UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	Docket No. ER22-1528

PROTEST OF CLEAN ENERGY AND CONSUMER ADVOCATES

Pursuant to Rule 211 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Rules of Practice and Procedure,[1] RENEW Northeast, Natural Resources Defense Council, Sierra Club, Conservation Law Foundation, Acadia Center, the Environmental Defense Fund, Sustainable FERC Project, Massachusetts Climate Action Network, PowerOptions, E2 (Environmental Entrepreneurs), and American Clean Power Association[2] (collectively, "Clean Energy and Consumer Advocates") respectfully submit this protest and comment on ISO New England Inc.'s ("ISO-NE" or "ISO") proposal under Section 205 of the Federal Power Act ("FPA") to adopt, after a two-year delay, buyer-side market power review and mitigation reforms (the "Delay Proposal") to its Transmission, Markets and Services Tariff ("Tariff").[3]

ISO-NE has failed to justify delaying long-overdue, necessary reforms to the region's Minimum Offer Price Rule ("MOPR"), which results in rates that are unjust, unreasonable, and unduly discriminatory.[4] The existing MOPR violates the FPA because it "distorts the market-clearing price" in the region's Forward Capacity Market ("FCM"), "forces customers to pay more than necessary to meet their capacity needs," "appears to act as a barrier to competition,

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[1] 18 C.F.R. §§ 385.211, 214.
[2] The views and opinions expressed in this filing do not necessarily reflect the official position of each of American Clean Power Association's individual members.
[3] Revisions to ISO Transmission, Mkts. and Servs. Tariff of Buyer-Side Market Power Review and Mitigation Reforms (Mar. 31, 2022) ("ISO Filing"), Accession No. 20220331-5296.
[4] *ISO-NE*, 178 FERC ¶ 61,050 (Jan. 21, 2022) (Glick & Clements, Chairman & Comm'r, concurring at P 2) ("Joint Concurrence").

insulating incumbent generators from having to compete with certain new resources that may be able to provide capacity at lower cost," and "increase[s] the costs of state policies."[5]

By leaving the existing MOPR in place for the region's 17th and 18th annual Forward Capacity Auctions ("FCA"), FCA 17 and FCA 18, the Delay Proposal would perpetuate unjust and unreasonable rates and lead to further harms. Clean Energy and Consumer Advocates urge the Commission to reject ISO-NE's unfounded and unduly discriminatory Delay Proposal and to exercise its authority under Section 206 of the FPA instead to require that ISO-NE implement a replacement Tariff proposal that would implement MOPR reforms without delay, starting in FCA 17, as ISO-NE previously committed to do in Docket No. AD21-10.[6] Specifically, Clean Energy and Consumer Advocates propose that the Commission require under Section 206 of the FPA that ISO-NE adopt and implement the proposal that it developed over eight months of discussions with New England Power Pool ("NEPOOL") stakeholders to implement MOPR reforms by FCA 17, and which was overwhelmingly endorsed by stakeholders at the NEPOOL Markets Committee on January 11, 2022 (the "Markets Committee Proposal").[7]

Our Protest is organized as follows. First, we discuss the standards of review under FPA Sections 205 and 206. Second, we provide important background on MOPR reform discussions in New England, including the development of ISO-NE's Delay Proposal and the alternative Markets Committee Proposal. Third, we discuss why MOPR reforms are essential in New

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[5] *Id.* (Glick & Clements, Chairman & Comm'r, concurring at PP 3–4).

[6] Pre- Conference Statement of ISO-NE, at 3, Docket No. AD21-10 (May 26, 2021) ("ISO will … begin outreach to the New England states and NEPOOL stakeholders, with the goal of developing a solution that is implementable, along with the elimination of the MOPR, in time for the seventeenth Forward Capacity Auction, for which qualification processes begin in March 2022."), Accession No. 20210526-4007.

[7] *See* Tariff Language Approved by the NEPOOL Markets Committee (2022) (attached hereto as Ex. D), https://www.iso-ne.com/static-assets/documents/2022/01/a02a_mc_2022_01_11-12_mopr_removal_iso_tariff_redlines_rev1.docx; ISO-NE Filing, Transmittal Letter at 75 (Mar. 31, 2022) ("Transmittal Letter"), Accession No. 20220331-5296; *id.* at 75.

England and why the Commission and ISO-NE must act to reform the existing unjust and unreasonable Tariff. Fourth, we explain why the ISO's Delay Proposal fails to adequately justify applying the MOPR to state-sponsored resources and why the Commission must reject this proposal as unjust and unreasonable. Finally, we explain why the Commission should use its Section 206 authority to require ISO-NE to implement the just and reasonable Markets Committee Proposal for MOPR reform instead and provide the rationale for doing so.

As we explain below, due to the limited time remaining before FCA 17, if the Commission agrees with Clean Energy and Consumer Advocates that ISO-NE's Delay Proposal is unjust and unreasonable and/or unduly discriminatory, it is critical that the Commission also require ISO-NE to implement the Markets Committee Proposal or a similar specific replacement rate, rather than leaving it to ISO-NE to develop a new just and reasonable replacement in the first instance. The latter approach would almost certainly lead to time-consuming further stakeholder proceedings that could leave consumers, investors, and the region still subject to the existing MOPR, which is an *even more* unjust and unreasonable rate than the Delay Proposal, in FCA 17 while occupying critical ISO-NE and stakeholder energies needed for other market reforms.

I. STANDARD OF REVIEW

FERC's authority over wholesale energy rates, charges, and any rules and regulations pertaining thereto is governed by two distinct but related sections of the FPA. While both Section 205 and Section 206 of the FPA require that such rates and charges be just, reasonable, and without undue preference or privilege,[8] the burden of proof and the roles of the utilities and the Commission shift between them.

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[8] 16 U.S.C. §§ 824d(a), (b); *id.* § 824e(a).

A. Section 205

Section 205 of the FPA requires that public utilities file notice regarding any proposed rate change with the Commission for approval at least 60 days prior to its proposed effective date.[9] Once filing parties submit a proposal, the Commission then must examine the rates, terms and conditions, and other tariff provisions that were filed and decide whether or not they are in fact "just, reasonable, and not unduly discriminatory,"[10] but the burden of establishing this lies with the filing utility.[11] Upon a finding that a tariff is not just or reasonable, FERC's authority in the Section 205 context is limited to rejecting the filing in whole or in part,[12] or with the filing parties' consent, the Commission may suggest "minor" modifications to a proposal, so long as such modifications are in line with the general scheme of the tariff.[13]

The requirement that rates be just, reasonable, and not unduly discriminatory is the same in both Sections 205 and 206 and Commission decisions in either context must be based on reasoned decision-making supported by substantial evidence.[14] As a general principle, the Commission has held that in "assuring just and reasonable rates, the Commission must strike a balance between setting a price that will provide an incentive to develop and retain a sufficient

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[9] *Id.*§ 824d(d).

[10] *Id.* § 824d(a)–(e); *Wisconsin Pub. Power, Inc. v. FERC*, 493 F.3d 239, 260 (D.C. Cir. 2007); *ISO*, 118 FERC ¶ 61,224, at P 12 (Mar. 19, 2007) ("The burden to provide a rationale and support for a proposed tariff revision in the first instance is on the Applicants and not the Commission" and rejecting applications based on unsupported assertions.).

[11] *See City of Winnfield v. FERC*, 744 F.2d 871, 874–75 (D.C. Cir. 1984).

[12] *See, e.g., NYPSC v. FERC*, 642 F.2d 1335, 1345 (D.C. Cir. 1980); *W. Res., Inc. v. FERC*, 9 F.3d 1568, 1574 (D.C. Cir. 1993); *Sea Robin Pipeline Co. v. FERC*, 795 F.2d 182, 183, 187 (D.C. Cir. 1986); *City of Winnfield*, 744 F.2d 871, 875, 876 (D.C. Cir. 1984).

[13] *W. Res., Inc.*, 9 F.3d at 1579; *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,043, at P 45 (July 17, 2020).

[14] 16 U.S.C. § 825*l*(b). *See also Emera Maine v. FERC*, 854 F.3d 9, 25 (D.C. Cir. 2017) ("Thus, while '[t]he 'just and reasonable' lodestar is no loftier under section 206 than under section 205,' *FirstEnergy*, 758 F.3d at 353, the showing required of FERC to exercise its section 206 authority to change an existing rate is different from anything required for FERC to approve a utility's proposed rate adjustment under section 205.").

level of capacity to ensure reliability, and protecting customers from overpaying for that capacity."[15] It must also balance the ability of states to pursue legitimate state policy goals.[16] In line with these principles, the Commission has rejected Section 205 proposals where they have failed to balance competing interests at issue, and where rate proposals are inconsistent with stated goals or lead to illogical results.[17] The Commission has also rejected rates that include transition mechanisms designed to delay impacts where such mechanisms lack a firm analytical basis and serve to delay efficient market signals.[18]

B. Section 206

Where the Commission has found—on its own motion or in response to a complaint—that a rate is unjust, unreasonable, or unduly discriminatory, Section 206 gives the Commission the authority to set the just and reasonable rate, rule, or practice.[19] As a result, a Section 205 proceeding may be transformed into a Section 206 proceeding and the Commission can impose a specific replacement rate if three conditions are met: (1) the proposed rate under Section 205 is determined to be unjust and unreasonable;[20] (2) the existing rate is unjust and unreasonable;[21] and (3) the replacement rate is just, reasonable, and supported by substantial evidence and

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[15] *ISO*, 158 FERC ¶ 61,138, at P 11 (Feb. 3, 2017); *see also New England Power Generators Ass'n, Inc*., 146 FERC ¶ 61,039, at P 52 (Jan. 24, 2014); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (evaluating whether end result of agency's balancing customer interests with utility's "legitimate concern with the financial integrity of the company" resulted in reasonable rates*)*.
[16] *ISO*, 155 FERC ¶ 61,023, at P 6 (Apr. 8, 2016) (citing *NESCOE*, 142 FERC ¶ 61,108 at P 35).
[17] *ISO*, 146 FERC ¶ 61,084, 61,354 (Feb. 11, 2014); *ISO*, 135 FERC ¶ 61,029, 61,146 (Apr. 13, 2011).
[18] *See, e.g., New York Indep. Sys. Operator, Inc*. ("NYISO"), 158 FERC ¶ 61,064, at P 55 (Jan. 27, 2017).
[19] 16 U.S.C. § 824e(a). *See also W. Res., Inc.*, 9 F.3d at 1579.
[20] *W. Res.*, 9 F.3d at 1579.
[21] *Id. See also Emera Maine*, 854 F.3d at 25 ("Section 206 therefore imposes a 'dual burden' on FERC. *FirstEnergy, 758 F.3d at 353.* Without a showing that the existing rate is unlawful, FERC has no authority to impose a new rate. *See Fla. Gas Transmission Co. v. FERC*, 604 F.3d 636, 640–41 (D.C. Cir. 2010) (examining similar requirement under the NGA); *Sea Robin Pipeline Co. v. FERC*, 795 F.2d 182, 187 (D.C. Cir. 1986) (same)").

reasoned rulemaking.[22] The Commission does not need to exercise its Section 206 authority in a separate proceeding since, as part of a Section 205 proceeding, it may discover facts that make changes pursuant to its Section 206 authority necessary.[23] Pursuant to its broad authority under Section 206, the Commission can implement reforms and amend tariffs based on what it determines to be just and reasonable rules and regulations.[24] Effectively, Section 206 puts the Commission in a more proactive position by leveraging its authority to reform tariffs on its own initiative.[25]

II. BACKGROUND

ISO-NE's MOPR has been controversial since its inception. New England states have long opposed the MOPR, including in their 2012 complaint that urged the Commission to reject the ISO's proposed Tariff provisions.[26] The states then as now have raised concerns that, by "exclud[ing] from the FCM new renewable resources developed pursuant to state statutes and regulations," the MOPR "will require electricity customers to purchase more capacity from the FCM than is necessary for resource adequacy," leading to excessive, unjust and unreasonable rates, and "unreasonably undermin[ing] legitimate public policies that are unrelated to the price

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[22] *W. Res.*, 9 F.3d at 1579–80 (citing *Tennessee Gas Pipeline Co. v. FERC*, 860 F.2d 446, 456 (D.C.Cir.1988)) (FERC must first determine "that the presumptively just and reasonable existing rate is no longer just and reasonable") (emphasis in original); *Sea Robin Pipeline Co.*, 795 F.2d at 184 (FERC must find "that the existing rate is unjust or unreasonable and the proposed new rate is both just and reasonable"); *ANR Pipeline Co. v. FERC*, 771 F.2d 507, 514 (D.C. Cir. 1985) (same).

[23] *Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656, 664 (D.C. Cir. 2017).

[24] Bethany Davis Noll & Burcin Unel, *Markets, Externalities, and the FPA: The Fed. Energy Regul. Comm'n's Authority to Price Carbon Dioxide Emissions*, 27 NYU Env't Law J. 1 (2019).

[25] Ari Peskoe, *A Challenge for Federalism: Achieving Nat'l Goals in the Elec. Indus.*, 18 Mo. Env't Law and Policy Review 209, 220–21 (2011).

[26] Compl. and Mot. to Consolidate Proceedings of the New England States Committee on Electricity ("NESCOE"), Docket Nos. EL13-34-000 and ER12-953-001 (not consolidated) (Dec. 28, 2012), https://nescoe.com/resource-center/fcm-re-exempt-dec2012/.

paid for capacity."[27] Over the last decade, the conflicts between the MOPR and states' public policies and consumers' interests have grown, as New England states have adopted increasingly ambitious state laws to address the dangers of climate change.[28] Both ISO-NE and the New England states now agree that the existing MOPR is unsustainable and must change.[29]

As ISO-NE's filing explains, the ISO has previously, though largely unsuccessfully, sought to accommodate state policy resources[30] alongside the MOPR, most recently through its adoption of its Competitive Auctions with Sponsored Policy Resources ("CASPR") rules, approved by the Commission in 2018.[31] CASPR replaced an earlier attempt to accommodate these resources in the market through a limited quantity Renewable Technology Resource ("RTR") exemption to the MOPR. The ISO recognizes in its filing that "both attempts maintained the MOPR in its original form, and were designed to permit entry of state-sponsored resources only to the extent doing so would not impact clearing prices in the Forward Capacity Auction. Perhaps as a result, neither mechanism has been viewed within the region as being

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[27] *Id.* at 1–2; *see also* NESCOE, *New England States' Vision for a Clean, Affordable, and Reliable 21st Century Reg'l Elec. Grid*, at 1–2 (Oct. 2020) ("The existing market structure is not fully compatible with certain state laws and mandates regarding resource adequacy and actions taken (e.g., longterm contracts) in pursuit of energy- and climate-related legal requirements. As a result, New England's wholesale markets fail to sufficiently value the legally-required clean energy investments made by the ratepayers they serve. Absent fundamental changes, as described below, the result of the existing market structure will be that some states' ratepayers will continue to overpay for electricity, constrained by a wholesale market not aligned with a rapidly transitioning resource mix and consumer investments in clean energy and decarbonization. That is not a sustainable outcome."), http://nescoe.com/resource-center/vision-stmt-oct2020/.

[28] Transmittal Letter at 33.

[29] *Id.* at 28 ("With the Continued Expansion of State Decarbonization Policies, the ISO's Long-Standing Buyer-Side Mitigation Rules Are No Longer Sustainable"); NESCOE, *New England States' Vision for a Clean, Affordable, and Reliable 21st Century Reg'l Elec. Grid*, http://nescoe.com/resource-center/vision-stmt-oct2020/.

[30] Generating resources receiving revenues from state government-regulated rates, charges, clean energy programs, etc. are currently defined as Sponsored Policy Resources under of the Tariff; the ISO's proposed revisions would amend this definition and expand it to include federal support. ISO Filing, Marked Tariff at § I.2.1.

[31] *ISO*, 162 FERC ¶ 61,205 (Mar. 9, 2018), reh'g denied by operation of law, *ISO*, 173 FERC ¶ 61,161 (Nov. 19, 2020).

particularly successful in accommodating state-sponsored resource entry into the market."[32] According to the ISO, "CASPR has not proven to date that it will facilitate" the entry of the significant levels of state policy resources now required under state laws.[33]

Recognizing that its existing MOPR is problematic and unsustainable, in May 2021, ISO-NE committed "to make a filing with the FERC to eliminate the MOPR in time for Forward Capacity Auction (FCA) 17."[34] Over the last year, ISO-NE's work on this effort was conducted in large part through the NEPOOL stakeholder process, in particular through the NEPOOL Markets Committee, which discussed and assessed "competitive capacity markets without a minimum offer price rule" during more than a dozen meetings over eight months, between June 2021 and January 2022.[35] For the vast majority of this effort, ISO-NE proposed, as it did in May 2021, to implement MOPR reforms by FCA 17. This resulted in the ISO's Markets Committee Proposal, which we describe further below, and which was overwhelmingly supported by stakeholders at the NEPOOL Markets Committee on January 11, 2022. On January 26, 2022, two weeks after the Markets Committee vote, ISO-NE announced in a memo to NEPOOL stakeholders that it had changed its position and no longer supported its originally stated goal of making a filing to eliminate the MOPR in time for FCA 17.[36] Instead, ISO-NE threw its support behind a Delay Proposal originally brought forward by incumbent gas entities, which would

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[32] Transmittal Letter at 5 (citations omitted).
[33] *Id.* at 6.
[34] ISO-NE, *Memo from Vamsi Chadalavada Re: Elimination of MOPR and Maintaining Competitive Pricing*, at 1 (May 17, 2021), https://www.iso-ne.com/static-assets/documents/2021/05/a0_memo_on_elimination_of_mopr.pdf.
[35] ISO-NE, *Competitive Capacity Markets without a MOPR* (June 8–9, 2021), https://www.iso-ne.com/static-assets/documents/2021/06/a05a_mc_2021_06_08_09_iso_presentation.pptx; Transmittal Letter at 75.
[36] ISO-NE, *Memo to NEPOOL Participants Committee re: ISO Support and Preference of Transition to Minimum Offer Price Rule (MOPR) Elimination*, at PDF p. 196 (Jan. 26, 2022), https://www.iso-ne.com/static-assets/documents/2022/02/npc-2022-02-03-composite4.pdf.

delay MOPR reforms for three years until FCA 19, two years later than the ISO had originally proposed. Below, we describe both the ISO's original Markets Committee Proposal and the Delay Proposal that ISO-NE has now filed with the Commission. In subsequent sections, we discuss in greater detail our concerns with both the existing MOPR and the ISO's Delay Proposal and explain why the Commission should take action under FPA Section 206 to direct ISO-NE to implement the Markets Committee Proposal instead.

A. ISO-NE's Original Markets Committee Proposal

The original MOPR reform proposal advanced by ISO-NE, and developed as part of an extensive NEPOOL Markets Committee process, included three proposed actions: (1) removal of the MOPR, including the Offer Review Trigger Price-related ("ORTP") design elements; (2) incorporation of a revised buyer-side market power review process; and (3) adjustment of the financial inputs used to calculate the Cost of New Entry ("CONE") and Net CONE, which are used in setting the FCA demand curve and other auction parameters, and an update to the FCM's Performance Payment Rate ("PPR") based on these updated values.[37] First, ISO-NE proposed, in its words, "removing MOPR and MOPR-related design elements," including the ORTP design, which ISO-NE indicated would eliminate the need for other market mechanisms intended to accommodate state policy resource entry, including CASPR's substitution auction.[38] Throughout

[37] ISO-NE Market Development, *Memo to Markets Committee re: Competitive Capacity Markets without a MOPR* (Jan. 5, 2022), https://www.iso-ne.com/static-assets/documents/2022/01/a02a_mc_2022_01_11-12_mopr_removal_iso_voting_memo.pdf.

[38] ISO-NE, *Competitive Capacity Markets without a MOPR: Discussion of ISO's proposal to remove MOPR and initial redlined market rules*, at 16 (Nov. 9–10, 2021), https://www.iso-ne.com/static-assets/documents/2021/11/a03b_mc_2021_11_09_10_iso_presentation_ccm_without_mopr.pdf. In its original proposal and its "Transition Mechanism," ISO-NE has framed the MOPR reform as MOPR removal. Because the proposed reforms involve changes to the MOPR and MOPR-related design elements, rather than actual elimination of the MOPR, it is more accurate to describe it as MOPR revision or redesign.

the NEPOOL Markets Committee process, ISO-NE consistently maintained that its plan was to file its MOPR proposal in time for the reforms above to take place in FCA 17.

As part of its original MOPR proposal, ISO-NE also proposed a revised buyer-side market power review process that would create three lanes of review: (1) a "no assessment" lane for two types of new capacity resources that would not be reviewed for buyer-side market power, namely those with a capacity equal to or less than five megawatts ("MW") and seasonal peak and on peak demand resources; (2) a "limited assessment" lane for certain new capacity resources that would undergo a limited assessment if they verified that they met one of two criteria, namely absence of any load serving entity relationship or arrangement, or meeting the definition of a "Sponsored Policy Resource," as defined under the Tariff;[39] and (3) a "full assessment" lane for all other new capacity resources, which would undergo a full buyer-side market power evaluation and be subject to a conduct an impact test (later changed to a conduct only test), and that would be allowed to demonstrate that they did not have an incentive to reduce the clearing price, in which case buyer-side mitigation would not be applied.[40]

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[39] The ISO's original Markets Committee Proposal and its filed Delay Proposal would both expand the definition of "Sponsored Policy Resource" under the Tariff to encompass federal as well as state policy resources. To date, concerns regarding the MOPR in New England have primarily centered around its exclusion of state policy resources, due to New England states' ambitious decarbonization policies. Likewise, in our comments, Clean Energy and Consumer Advocates generally refer to state rather than federal policy resources; however, we support expanding Sponsored Policy Resource to also cover federal policy resources and note that excluding federal policy resources under the MOPR would lead to the same inefficiencies and harms as we describe for state policy resources.

[40] ISO-NE, *Competitive Capacity Markets without a MOPR: Discussion of ISO's proposal to remove MOPR and initial redlined market rules*, at 4–12 (Nov. 9–10, 2021), https://www.iso-ne.com/static-assets/documents/2021/11/a03b_mc_2021_11_09_10_iso_presentation_ccm_without_mopr.pdf; *see also* ISO-NE Market Development, *Memo re: Overview of New Proposed Buyer-Side Market Power Mitigation Measures*, at 2–5 (Nov. 4, 2021) (revised edition of October 6, 2021 Memo), https://www.iso-ne.com/static-assets/documents/2021/11/a03b_mc_2021_11_09_10_iso_memo_bsm.pdf; ISO-NE Market Development, *Memo re: Competitive Capacity Markets without a MOPR (WMPP ID: 159) – Further Updates to Tariff Revisions* (Jan. 4, 2022), https://www.iso-ne.com/static-assets/documents/2022/01/a02a_mc_2022_01_11-12_mopr_removal_iso_memo_changes_since_december_mc_meeting_further_updates_to_tariff_revisions.pdf.

Finally, ISO-NE proposed to adjust certain financial inputs used to calculate CONE and Net CONE, namely the cost of debt, cost of equity, and debt weight, resulting in an 11 percent increase in CONE, from $12.400/kW-mo to of $13.791/kW-mo, and a 16 percent increase in Net CONE, from $7.468/kW-mo to $8.665/kW-mo, for FCA 17.[41] ISO-NE based these CONE and Net CONE adjustments on a 2021 report of its External Market Monitor ("EMM"), which observed that a material consequence of eliminating the MOPR is that future FCM prices may become more volatile, resulting in increased financial risk for merchant resource owners and developers. To address this risk, the EMM recommended the 16 percent increase in the Net CONE value for FCA 17 to reflect an increase in that cost of capital.[42] ISO-NE also proposed to increase the FCM's PPR by 16 percent, from $9,337/MWh to $10,833/MWh, based on the same EMM analysis.[43]

1. Stakeholder Discussions and Votes at the Markets Committee

ISO-NE's Markets Committee Proposal was discussed and developed with stakeholders over eight months, with the consistent aim of eliminating the MOPR in advance of FCA 17. At the January 11, 2022, meeting of the NEPOOL Markets Committee, stakeholders voted to recommend a motion that the NEPOOL Participants Committee support ISO-NE's proposal, with a 74.04 percent vote in favor.[44] At the same meeting, the NEPOOL Markets Committee also

[41] ISO-NE, *Competitive Capacity Markets without a MOPR – Continued Review of Tariff Redlines*, at 29 (Dec. 7–9, 2021), https://www.iso-ne.com/static-assets/documents/2021/12/a02a_mc_2021_12_07_09_iso_presentation.pptx.
[42] Potomac Econ., *Evaluation of Changes in the MOPR on Financial Risk in New England*, at 5–6, 48 (Nov. 2021), https://www.potomaceconomics.com/wp-content/uploads/2022/01/a00_nov_9_10_mc_meeting_materials_2nd_set.zip.
[43] ISO-NE, *Competitive Capacity Markets without a MOPR – Continued Review of Tariff Redlines*, at 29 (Dec. 7–9, 2021), https://www.iso-ne.com/static-assets/documents/2021/12/a02a_mc_2021_12_07_09_iso_presentation.pptx.
[44] Transmittal Letter at 75; Clean Energy and Consumer Advocates that are members of NEPOOL (i.e., Acadia Center, Conservation Law Foundation, Environmental Defense Fund, Natural Resources Defense Council, and PowerOptions) voted in favor of ISO-NE's proposal.

considered a proposal advanced by three incumbent gas entities—Dynegy Marketing and Trade, LLC, Calpine Energy Services, LP, and Nautilus Power LLC—to delay these MOPR reforms until FCA 19. Prior to the vote on this proposal, ISO-NE indicated that if there was "broad support" for delay from NEPOOL and if the majority of states were unopposed, ISO-NE planned to adopt the delay proposal, with potential conforming edits.[45] The delay proposal failed, with only 23.79 percent of NEPOOL stakeholders in favor.[46] Despite the lack of broad support—or even a majority—from NEPOOL, ISO-NE issued a memo fifteen days later, on January 26, 2022, in which it nevertheless expressed its preference for delaying MOPR reform until FCA 19, and its intent to adopt and file a delay proposal if it was supported by stakeholders.[47] ISO-NE's Delay Proposal, and stakeholder positions on the proposal, are discussed below.

B. ISO-NE's Delay Proposal

The ISO's Delay Proposal centers around a so-called "Transition Mechanism" that would maintain the existing MOPR and MOPR-related mechanisms for FCA 17 and FCA 18, and delay implementation of ISO-NE's proposed MOPR reforms for three years, until FCA 19 in 2025. According to ISO-NE, the primary driver for the proposed delay is its "concerns with the potential adverse reliability impacts of the MOPR's immediate elimination."[48] As discussed more fully in the testimony of Abigail Krich (attached as Exhibit A) and in Section IV, *infra*,

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[45] NEPOOL Mkts. Comm., *January 11–12, 2022 Meeting Minutes*, at 9 (2022), https://www.iso-ne.com/static-assets/documents/2022/02/a01a_mc_2022_02_08_minutes_jan_mc_draft_rev4.docx.
[46] Transmittal Letter at 75.
[47] ISO-NE, *Memo to NEPOOL Participants Comm. re: ISO Support and Preference of Transition to MOPR Elimination*, at PDF p. 196 (Jan. 26, 2022), https://www.iso-ne.com/static-assets/documents/2022/02/npc-2022-02-03-composite4.pdf.
[48] Transmittal Letter at 37.

ISO-NE has failed to substantiate the need for its two-year delay proposal, or the effectiveness of the proposed delay in achieving its purported reliability objective.[49]

ISO-NE's Delay Proposal differs in several ways from the original proposal approved by the Market Committee. First and foremost, despite eight months of stakeholder consultation and deliberation on the immediate removal of the MOPR in time for FCA 17, the ISO's Delay Proposal proposes that MOPR reforms not take effect until FCA 19, two years after FCA 17. Despite the ISO's proffered rationale for the two-year extension of the MOPR—its purported need to make certain other "market design enhancements" (including to its resource accreditation and ancillary service rules) in order to address concerns it believes will arise "with high renewables penetration"—the ISO's proposal provides no firm commitment to enact such reforms and "underscore[s] that the proposed package . . . is <u>not</u> contingent upon completion of either of those market reforms or filings" since "it is simply not possible to guarantee . . . [that they] will be completed for FCA 19."[50]

Second, the Delay Proposal would reinstitute the previously abandoned RTR exemption, this time in the amount of 300 MW for FCA 17 and 400 MW for FCA 18. As ISO-NE admits, the 700 MW value was originally proposed by the incumbent gas entity proponents of the so-called "Transition Mechanism" and was not the result of any independent analysis or review by the ISO. As ISO-NE describes, the incumbent gas entity proponents believed that the proposed

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[49] Throughout its filing, ISO-NE describes its two-year delay proposal as a "stepped" and "graduated" transition toward MOPR elimination, but there is nothing gradual or transitional about it. ISO-NE proposes RTR exemptions, but those only create the possibility of exemption from the effects of MOPR for certain qualifying resources. They do nothing to eliminate the MOPR. The fact is that the MOPR remains untouched and in effect until at least FCA 19.

[50] Test. of Vasmi Chadalavada on Behalf of ISO-NE Regarding the Need for a Transition to the MOPR's Elimination, at 46, 12–13 (Mar. 30, 2022) ("Chadalavada Direct"), Accession No. 20220331-5296; Transmittal Letter at 45.

RTR Exemption level was a “reasonable amount of capacity to exempt from the MOPR” for the two-year period between FCA 17 and FCA 19.[51]

Third, unlike the Markets Committee Proposal, ISO-NE’s Delay Proposal does not propose any specific changes to CONE, Net CONE, or PPR values based on the EMM’s analysis. Instead, ISO-NE indicates that it would intend to continue to work with the EMM, states, and stakeholders during the MOPR reform delay period to “monitor the impact of the MOPR’s elimination.”[52] Then, unless further analysis by the EMM suggests that a cost of capital adjustment for FCA 19 is unnecessary, ISO-NE would plan to propose such an adjustment to stakeholders for implementation with the full elimination of the MOPR for FCA 19.[53]

Fourth, the Delay Proposal retains CASPR’s substitution auction for FCA 17 and FCA 18 but would remove the test price rules that apply to that auction.[54] According to ISO-NE, the rationale for removing the test price is that doing so may be a way to facilitate more participation by existing resources in the substitution auction.[55] As ISO-NE acknowledges in its filing, there has been a lack of activity in the substitution auction: only 54 MW of demand (i.e., existing resources willing to accept payments to exit the market) entered the substitution auction for FCA 13; no demand entered the substitution auction for either FCA 14 or FCA 15; and while participation of demand in FCA 16 was more robust, the auction did not see any capacity obligations trading hands.[56] As a result, of the 900 MW of state policy resources that have

[51] Transmittal Letter at 42.
[52] *Id.* at 46.
[53] *Id.*
[54] *Id.* at 63.
[55] *Id.* at 68.
[56] *Id.* at 28.

attempted to enter the FCM over CASPR's four year history, only 54 MW have actually been able to do so.[57]

1. Stakeholder Discussions and Votes at the Participants Committee and New England States' Positions

As noted above, ISO-NE first expressed its preference for the Delay Proposal in a memo on January 26, 2022, reversing its support for the Markets Committee Proposal that it had developed with stakeholders over the previous eight months. This memo was provided to stakeholders just one week before the final stakeholder vote was scheduled to take place on February 3, 2022, at the NEPOOL Participants Committee. As noted in the minutes from the February 3 meeting, stakeholders opposed to the Delay Proposal expressed disappointment and frustration with the ISO's sudden change in position.[58] Some NEPOOL members argued that delaying MOPR reforms would extend a market construct that they viewed as an unjust and unreasonable barrier to entry for new renewable resources.[59] Opponents of the delay also argued that continuing CASPR for two more years would continue to provide discriminatory treatment to renewable resources by requiring owners of these resources to make payments to existing resources in order to have the opportunity to earn capacity revenues in the FCM.[60] Some opponents also argued that ISO-NE's reliability rationales for supporting the delay were opinions and conjecture that lacked quantitative analysis in support.[61] Ultimately, however, at the ISO's urging, on February 3, the NEPOOL Participants Committee approved an amendment offered by

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[57] Transmittal Letter at 27.
[58] NEPOOL Participants Comm., Suppl. Notice of March 3, 2022 NEPOOL Participants Comm. Teleconference Meeting, at PDF pp. 11–14 (Feb. 24, 2022), https://nepool.com/wp-content/uploads/2022/02/NPC_20220303_Composite4.pdf.
[59] *Id.*
[60] *Id.*
[61] *Id.*

incumbent gas entities to delay MOPR reforms from FCA 17 until FCA 19 with 61.49 percent of stakeholders voting in favor, on a 60 percent threshold vote.[62] Subsequently, the Participants Committee approved ISO-NE's Delay Proposal, incorporating the delay amendment, with 69.56 percent voting in favor.[63] Consistent with that vote, ISO-NE and NEPOOL jointly filed the Delay Proposal with the Commission on March 31, 2022.

The New England states have a clear stake in the outcome of MOPR reform, as outlined in ISO-NE's filing to the Commission.[64] Representatives of state agencies and of NESCOE, which represents the collective perspective of the states' governors, are invited to NEPOOL meetings and given an opportunity to express their views on NEPOOL matters. Because the states are not voting members of NEPOOL, however, ISO-NE, stakeholders, and the Commission must rely on statements and other representations by the states, individually and/or collectively, from both inside and outside of NEPOOL meetings, to understand their positioning on MOPR reform and other issues. New England state legislators also have a stake in ensuring that ISO-NE's wholesale market rules are compatible with and do not undermine their adopted state energy and decarbonization laws, though these legislators are not represented in ISO-NE's stakeholder process at NEPOOL.

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[62] *Id.* at PDF p. 14.

[63] The increase in support between the first vote on the delay amendment and the second and final vote on the Delay Proposal likely reflects the fact that, once the delay amendment passed, the Delay Proposal became the *only* proposal by which stakeholders could express support for MOPR reforms in a NEPOOL vote. In other words, some stakeholders opposed to the delay amendment may nevertheless have concluded that *some* version of MOPR reform, including the Delay Proposal, was better than none. Had ISO-NE wanted, it could also have asked for a separate vote on the Markets Committee Proposal; however, as the ISO no longer supported that proposal, it elected not to request such a vote. Procedurally, no other party was permitted to ask for such a vote at the Participants Committee. Clean Energy and Consumer Advocates that are members of NEPOOL (i.e., Acadia Center, Conservation Law Foundation, Environmental Defense Fund, PowerOptions, and Natural Resources Defense Council) voted in opposition to both the delay amendment and the final vote on ISO-NE's Delay Proposal. *Id.* at PDF pp. 15, 20–22.

[64] *See, e.g.*, Transmittal Letter at 12–21 (discussing "State Clean Energy Policies and Decarbonization Goals").

As discussed above, over the last decade, NESCOE and individual New England states have repeatedly expressed their concerns with and opposition to the MOPR and emphasized the need for reform. ISO-NE states that its Delay Proposal was "developed by stakeholders during the course of the NEPOOL stakeholder process in consultation with the ISO and the New England states" and that the "states contracting for these renewable resources are not opposed to this [700 MW] exemption value."[65] But without more information from state energy and environmental agencies or governors, it is difficult to know their exact positioning on ISO-NE's Delay Proposal. During the February 3, 2022, NEPOOL Participants Committee meeting, the individual states were silent on the Delay Proposal—there is no indication in the minutes that any views were expressed by any individual state. A representative of NESCOE noted that NESCOE "would not oppose" the two-year delay proposal.[66] After the Participants Committee meeting, NESCOE further issued a statement indicating that it had expressed the view that "it would not oppose the transition approach if it was adopted by ISO New England and supported by NEPOOL."[67] NESCOE also explained, however, that "it is inappropriate to apply the MOPR to state investments to meet clean energy mandates and that such markets are not sustainable over the long-term" and that "MOPR reforms should be enacted as soon as possible in a manner that supports system reliability."[68] While ISO-NE implies that New England states support its

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[65] *Id.* at 7, 42.
[66] NEPOOL Participants Comm., Suppl. Notice of March 3, 2022 NEPOOL Participants Comm. Teleconference Meeting, at PDF p. 12 (Feb. 24, 2022), https://nepool.com/wp-content/uploads/2022/02/NPC_20220303_Composite4.pdf.
[67] NESCOE, *NESCOE Perspective Communicated to NEPOOL and ISO New England on the Minimum Offer Price Reform* (Feb. 8, 2022), https://nescoe.com/resource-center/mopr-perspective-2022/.
[68] *Id.*

proposed delay, as one New England state official recently pointed out, in clarifying the NESCOE position, "[i]t's a long way from not opposing to supporting."[69]

In the instant docket, state and federal legislators from New England, including many state legislators responsible for adopting New England states' decarbonization policies and clean energy requirements into law, have expressed opposition to the Delay Proposal and have urged the Commission to require ISO-NE to implement MOPR reforms expeditiously.[70]

III. ISO-NE'S EXISTING MOPR IS UNJUST AND UNREASONABLE

A. New England's Clean Energy Transition Requires Reform of ISO-NE's Capacity Market

As ISO-NE points out, New England "is unquestionably on a path to a clean energy future" where a dramatic transition has shifted energy generation away from fossil fuels towards a grid with increased renewable intermittent resources and distributed generation.[71] The pace of this transition is driven by public policies geared toward addressing the environmental externalities associated with fossil fuel-based energy generation as well as technological advancements that are expanding the capabilities and lowering the costs of clean resources.[72]

As catalogued by the ISO-NE Filing, the New England states have some of the nation's most ambitious climate and clean energy and economy-wide decarbonization targets.[73] Four of

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[69] Jan Ellen Spiegel, *New England takes a detour on grid reform; griping ensues*, CT Mirror (Feb. 23, 2022), https://ctmirror.org/2022/02/23/new-england-takes-a-detour-on-grid-reform-griping-ensues/.
[70] Letter from U.S. Senators Edward J, Markey, Elizabeth Warren, and Bernard Sanders to Chairman Glick Docket, at 1 (Apr. 14, 2022) ("We urge FERC to reject ISO-NE's proposal to delay the MOPR elimination, and instead support its full and prompt repeal."), Accession No. 20220414-4005, https://www.markey.senate.gov/download/iso-ne-mopr-letter-to-ferc; Nat'l Caucus of Env't Legislators Letter, Docket No. ER22-1528-000 (April 20, 2022), Accession No. 20220420-5302.
[71] ISO-NE, *New England's Future Grid Initiative Key Project*: *Project Overview* at https://www.iso-ne.com/committees/key-projects/new-englands-future-grid-initiative-key-project/.
[72] *Id*; *see also* NESCOE, *New England States' Vision for a Clean, Affordable, and Reliable 21st Century Reg'l Elec. Grid* (Oct. 2020) (hereinafter "NESCOE Vision Statement"), https://yq5v214uei4489eww27gbgsu-wpengine.netdna-ssl.com/wp-content/uploads/2020/10/NESCOE_Vision_Statement_Oct2020.pdf.
[73] *Id.* § 2.

the states have 100% net-zero emission targets for their energy portfolios.[74] These electric sector targets, together with other public policies such as pollutant emission limits, significantly affect which resources enter and exit ISO-NE's markets.[75] As a result, state policies—not the FCM—are expected to be the principal driver of changes to the resource mix in New England over the next two decades.[76] ISO-NE's capacity market must evolve to rely on an increasing share of emerging resources like utility-scale wind, solar, battery storage, and distributed energy resources ("DERs"), including demand response and energy efficiency resources, which reduce demand for electricity and thereby help maintain resource adequacy.[77] However, it cannot do so efficiently or effectively with a Tariff that pushes many state policy resources out of the capacity market and forces consumers to buy unneeded capacity from fossil fuel resources.

As pointed out by Chairman Glick and Commissioner Clements:

> Over the last few years, the Commission cast aside its traditional balancing and adopted sweeping MOPR rules in all three Eastern RTOs/ISOs that made no effort to tailor mitigation to the risk of buyer-side market power, thereby abandoning its duty to weigh whether the benefits of mitigation outweigh the harms. As a result, MOPRs have transitioned from a rarely invoked tool for addressing a particular form of anti-competitive conduct to a comprehensive regime that mitigates the capacity offer of most new resources—regardless of market power—fundamentally distorting the market that it is nominally supposed to protect."[78]

[74] Transmittal Letter at 12–21. As part of these efforts, the region has already contracted for, or authorized procurement of, up to 10,622 MW of renewable resources. *Id.* at 21.

[75] *See, e.g.*, *id.* at 30 (noting that aggressive state decarbonization goals will intensify the need for additional renewable and clean resources to meet them and highlighting the change in the resulting transformation of New England's generation mix).

[76] *Id.; see also* Chadalavada Direct at 47 (state policy resources required to meet state environmental policy goals receiving financial support from outside of FCM are more likely than others to achieve commercial operation and expecting development to continue to increase rapidly, regardless of MOPR).

[77] *See* Kathleen Spees et al., The Brattle Group, *The Benefits of Energy Efficiency Participation in Capacity Markets*, at i (Apr. 2021), https://www.aee.net/hubfs/The%20Benefits%20of%20Energy%20Efficiency%20Participation%20in%20Capacity%20Markets1.pdf.

[78] *Statement of Chairman Glick and Comm'r Clements*, at P 9, Docket No. 21-2582-000 (2021), Accession No. 20211019-4001 (citing, in part: "*Md. People's Counsel v. FERC,* 761 F.2d 768, 779 (D.C. Cir. 1985) (stating that the law "demand[s] an articulation, in response to serious objections, of the

As discussed in further detail below, the harms caused by the expansive MOPR regime have already cost ISO-NE customers hundreds of millions of dollars and are poised to start costing customers *billions* of dollars for capacity that they do not need while also continuing to burden environmental justice and frontline communities with the environmental harms of fossil fuel plants that would otherwise retire. ISO-NE's Section 205 filing offers the Commission a chance to reconsider the unjust, unreasonable, and unduly discriminatory rates that have resulted from the string of Commission orders establishing ISO-NE's current Tariff and MOPR rules.[79] As the Commission is aware, the most recent of its major orders here—approving ISO-NE's CASPR rules—is on appeal before the D.C. Circuit Court of Appeal and has been held in abeyance until July 22, 2022,[80] in anticipation of this filing by ISO-NE.[81] Litigation involving a number of Clean Energy and Consumer Advocates members in that matter is linked to the outcome in this case, as the Commission's decision in this matter has the potential to moot the issues on appeal.[82] Arguments regarding the unjustness, unreasonableness, and undue discrimination that result from

Commission's reasons for believing that more good than harm will come of its action" (emphasis added)); *Edison Mission Energy, Inc. v. FERC*, 394 F.3d 964, 969 (D.C. Cir. 2005) (acknowledging that the seller-side market power mechanism at issue "may well do some good by protecting consumers and utilities against price increments caused by the exercise of market power" but may "also wreak substantial harm-in curtailing price increments attributable to genuine scarcity"). Although this case involved seller-side market power—which we explain later in this statement is appropriately addressed in a distinct manner from buyer-side market power—the discussion of the Commission's required balancing of potential benefits and harms to come from its actions is no less relevant in the buyer-side market power context.").

[79] *See, e.g.*, *NESCOE v. ISO-NE*, 142 FERC ¶ 61,108; *ISO-NE*, 162 FERC ¶ 61,205; *ISO-NE*, 169 FERC ¶ 61,013 (Oct. 7, 2019); *ISO-NE*, 173 FERC ¶ 61,161; *ISO-NE*, 175 FERC ¶ 61,195 (June 7, 2021).

[80] Order, *Sierra Club v. FERC, No.* 20-1333 (D.C. Cir. Oct. 25, 2021), ECF No.1919366.

[81] *See* Unopp. Mot. for Continued Abeyance, at 3–4, *Sierra Club v. FERC,* No. 20-1333 (D.C. Cir. Oct. 22, 2021), ECF No. 1919354.

[82] *Id.* Clean Energy and Consumer Advocates incorporate herein by reference the same expert and legal criticisms leveled against its application in ISO-NE by the members of Clean Energy and Consumer Advocates participating in that proceeding, review of which is pending before the D.C. Circuit Court of Appeals. *See, e.g.*, Protest of Clean Energy Advocates, Docket No. ER18-619-000, Accession No. 20180129-5431 (Jan. 29, 2018); Req. for Reh'g of Clean Energy Advocates, Docket No. ER18-619-000, Accession No. 20180409-5311 (Apr. 9, 2018); Req. for Reh'g of Nat. Res. Def. Council, Docket No. ER18-619-002, Accession No. 2021221-5365 (Dec. 21, 2021).

ISO-NE's current Tariff have been extensively discussed in the filings in the Commission's docket pertaining to CASPR, and Clean Energy and Consumer Advocates will not repeat them all here. Instead, we focus on key issues that demonstrate why the economic theory underpinning the MOPR has always been irredeemably flawed and why the Commission must decisively require its immediate and permanent reform to exclude application of the MOPR to state policy resources.

B. Application of the MOPR to State Policy Resources Is Based on Flawed Economic Logic

The expansion of the MOPR to circumstances beyond actual exercises of buyer-side market power, and the Commission's recent orders applying the MOPR to all state policy resources, do not reflect sound economic reasoning.[83] The economic theory underpinning this expansion of MOPR alleges that states with aggressive decarbonization mandates are incenting the development of large quantities of new zero- or low-carbon resources to meet system-wide transition deadlines through a variety of programs and contract solicitations that the Commission has described as "subsidies."[84] Because these activities can sometimes lower near-term capacity market prices and/or displace "non-subsidized" resources, proponents of the MOPR argue that intervention is necessary to "protect" wholesale capacity market prices. The allegation is that without intervention, market prices will be too low for merchant capacity suppliers (particularly fossil fuel resources) to earn adequate returns on investment and that, over time, these low

[83] Written Test. of Dr. Kathleen Spees and Dr. Samuel A. Newell, *Economic Impacts of the MOPR within the ISO-NE Capacity Market*, at 4 (April 21, 2022) (attached hereto as Ex. B) ("Brattle Aff.").
[84] *See, e.g.*, *ISO-NE*, 173 FERC ¶ 61,161, at P 131; Brattle Aff., Attach. A, Written Test, of Dr. Kathleen Spees and Dr. Samuel A. Newell, *Economic Impacts of the Expansive Minimum Offer Price Rule within the PJM Capacity Market* at 15, Docket No. ER21-2582-000 (Aug. 27, 2021), Accession No. 20210827-5205 ("Brattle PJM Aff.").

capacity market prices will lead to insufficient entry of new generating resources and exit of inefficient resources that will ultimately threaten reliability of the whole electric system.[85]

The proffered remedy is to negate any incentives provided to state policy resources by applying the MOPR to every capacity supply offer that receives even a negligible or indirect benefit pursuant to state policy. This would force resources benefiting from state policies to bid at administratively determined rates that would reflect the higher prices that would prevail in the absence of state decarbonization policies.[86]

As explained by the experts at the Brattle Group, who ISO-NE routinely employs for advice on its market designs and to assist with the implementation of the ISO-NE Tariff,[87] these theories rest on flawed economic logic.[88] Simply put, "there is no sensible economic rationale for applying MOPR to all policy resources."[89] Moreover, applying the MOPR to policy-supported resources pushes these resources out of the capacity market, with a number of undesirable consequences, namely: (1) policy resources are deprived of revenues commensurate with the capacity value they provide; (2) incentives are created for retaining and developing uneconomic excess capacity supply that is not needed for reliability; (3) market clearing prices are artificially inflated and disconnected from actual supply-demand conditions, which effectuates a wealth transfer from customers to incumbent suppliers; and (4) these distortions become unsustainable over time as states across the ISO-NE footprint pursue their clean energy

[85] *Id. See also ISO-NE*, 173 FERC ¶ 61,161, at P 129.
[86] Brattle PJM Aff. at 15.
[87] Drs. Spees and Newell have worked extensively for ISO-NE on its market design and tariff implementation, including with regard to the MOPR. *See* Brattle Aff. at 1–2.
[88] *Id.* at 4–5; Brattle PJM Aff. at 4,15–23.
[89] Brattle PJM Aff. at 4.

and other policy objectives, leaving behind a capacity market totally disconnected from the reality of the resources actually operating on the grid.[90]

A corrected economic analysis should consider the following fundamental economic principles:

1. <u>The Purpose Of A Capacity Market Is To Support Reliability *At Minimal Cost To Consumers* Through Price Signals Capable Of Guiding The Orderly Entry And Exit Of Resources</u>

Electricity capacity markets are a means to an end, not an end in themselves.[91] Their purpose is to protect the public from excessive costs for maintaining resource adequacy, which is the ability of the electric system to supply electrical demand at all times. In most of the United States, the electric system is considered "adequate" if the system has enough supply available to ensure that an involuntary loss of load (blackout) occurs no more than once every ten years.[92] Ensuring adequate resource capacity involves a complex combination of forecasting demand and providing sufficient incentives to ensure future supply will be online to meet that demand.

Capacity markets are just one of several non-exclusive approaches to maintaining resource adequacy. All competitive wholesale markets operated by RTOs/ISOs employ energy and ancillary service markets to provide electricity to customers on a short-term basis. These short-term markets reflect the marginal cost of system operations at granular locational levels and short time intervals.[93] These markets also provide incentives for long-term resource investment (retirement or new entry) by providing a basis for forward price expectations. The

[90] Brattle Aff. at 5–7; Brattle PJM Aff. at 4–5. The ISO itself has acknowledged these consequences. *See* Transmittal Letter at 29.
[91] *NYPSC v. NYISO*, 173 FERC ¶ 61,060 (Oct. 15, 2020) (Glick, Comm'r, dissenting at P 15).
[92] Johannes P. Pfeifenberger et al., *Resource Adequacy Requirements: Reliability and Econ. Implications*, The Brattle Group & Astrape Consulting, at iii (Sept. 2013), https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf.
[93] Devin Hartman, *Enhancing Market Signals for Elec. Resource Adequacy*, R Street Inst., at 5 (Dec. 2017), Policy Study No. 123.

revenues from marginal cost pricing, however, are often insufficient to cover the costs of resources at a level necessary to meet reliability standards.[94] RTOs/ISOs therefore employ a variety of approaches (including contracting, scarcity pricing, and capacity markets) to supplement the signals provided by the energy and ancillary services markets to facilitate new investment, retirement decisions, and participation by demand response.

Capacity markets are intended to employ a market-based approach to address the "missing money" that resources need to remain viable but are sometimes unable to earn solely by providing energy and ancillary services. Specifically, they provide price signals through a competitive capacity auction design that sets prices at the intersection of sellers' capacity market supply offers and the administrative demand curve. Under this framework, the market produces prices consistent with supply-demand conditions. The market produces low prices when there is more than enough supply to meet resource adequacy needs, and it produces high prices when capacity supply is scarce.[95] Capacity markets are thus a mechanism for attracting new investments and retaining supply in which private parties may respond to competitive pricing signals to enter the market when supply is tight (and prices are high) or exit the market when supply is long (and prices are low).

Efficient outcomes in capacity markets rely upon resources competing with each other to require as little capacity market revenue as possible to cover their going-forward costs. For the market to be truly competitive, resources must have the flexibility to reflect and bear the risk of their own expertise, experience, technology, risk tolerance, and whatever else might provide them with a competitive advantage in the quest to provide capacity at the lowest possible

[94] *Id.*
[95] Brattle PJM Aff. at 10.

cost.[96] Capacity sellers offer their resources into the market at the minimum price they are willing to accept to come online or stay in the market.[97] For any given resource, the minimum price they are willing to accept is driven by a number of factors including primarily: (a) costs associated with bringing new supply into the market or maintaining an existing facility that needs re-investment, minus (b) any anticipated net revenues that could be earned from energy markets, ancillary service markets, or other revenue sources (such as sales of renewable energy credits ("RECs"), steam, or gypsum).[98] Many sellers also adjust their capacity offer price based on any bilateral sales agreements for capacity or any co-products they may produce; as well as based on their long-term view of future energy and capacity prices.[99] Sellers that are able to pre-sell most of their capacity or energy through bilateral contracts would typically have their going-forward costs covered by their anticipated revenues and so, using the formula above, would offer into the capacity market at a zero price, as would most sellers that have already come online and have few going-forward capital investments.[100]

2. <u>The State Policies at Issue Address Well-Understood Market Failures Such as Environmental Externality Costs</u>

The theory that state policy resources receiving out of market support creates "market distortions"[101] is an overly simplistic and incomplete analysis that overlooks a well-understood fact that market forces often fail to account for negative externalities—i.e., negative side effects of production that adversely affect a party not involved in the transaction who has no influence on whether the transaction occurs, but is nevertheless harmed by it.[102] Absent intervention to

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[96] *NYPSC v. NYISO*, 173 FERC ¶ 61,060 (Glick, Comm'r, dissenting at P 5).
[97] Brattle PJM Aff. at 10.
[98] *Id*.
[99] *Id*.
[100] *Id*.
[101] *ISO-NE*, 173 FERC ¶ 61,161, at P 66; *ISO-NE*, 162 FERC ¶ 61,205, at P 21; Brattle PJM Aff. at 4.
[102] Brattle PJM Aff. at 16.

address them, neither the purchaser nor the seller pays the full costs associated with the negative externality.[103] When externalities are at play, markets fail to allocate resources efficiently and the current market price of that good is not the economically "correct" one, such that what looks like "market forces" are really market failures.[104]

Environmental externalities (for example, unregulated pollution emitted as a byproduct of fossil fuel electric generation) are a textbook example of market failures that have grievous harms such as asthma and early deaths.[105] Market pricing that does not account for such negative externalities would drive resource investments and operations toward an inefficiently large quantity of fossil-fuel fired power plants, imposing inefficiently high externality costs.[106]

As explained by Brattle, market externalities can be addressed in one of two ways: (1) command-and-control policies that directly regulate behavior, or (2) market-based policies that align private incentives with social efficiency.[107] In the case of electricity markets, environmental externalities can be addressed through policy mechanisms such as pollutant pricing mechanisms (e.g., carbon pricing) or through clean energy attribute payments paid directly to resources. These policies deliberately reward non-polluters and discourage polluters by forcing generators to internalize the environmental costs of their production, and both will have the effect of raising market prices for generators who pollute and lowering it for those who do not.[108] The Commission's brief line of cases that would nullify state policy actions that it deems to provide a direct benefit, while expressing support and accommodation for policy actions that impose a direct penalty (e.g., a carbon tax), ignores that these are two sides of the

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[103] *Id.*
[104] *Id*.
[105] *Id*.
[106] *Id.*
[107] *Id.* at 16–17.
[108] Brattle PJM Aff. at 17.

same economic coin with the same end result: narrowing the cost gap between non-emitting resources and fossil fuel resources.[109]

When viewed through the proper lens, payments made to non-polluting resources as "subsidies" are not subsidies in the traditional sense of the term of propping up an "economically inefficient" market player. Rather, the incentives provided by states in this context are more appropriately described as compensation provided for the environmental benefits these resources provide that are necessary to correct a market failure.[110] Compensation for the environmental value of policy-supported resources should not be considered an illegitimate distortion of markets that must be excluded, but rather a correction that is needed to achieve a more efficient outcome.[111]

3. The "Correct" Capacity Price Is the One that Aligns Supply with Demand (Not the Price That Would Prevail in the Absence of State Policies)

The "correct" capacity price in a competitive and efficient market is the one that accurately reflects underlying fundamentals of supply and demand and can accurately signal when and where capacity investments are needed (and when high-cost resources can retire).[112] When new resources are required to offer capacity at administratively-determined prices (i.e., offer price floors) that negate out-of-market revenues, it creates a systemic bias in favor of existing resources and curtails resources' incentive and ability to compete across all possible dimensions. This bias has a chilling effect on the development of new technologies and resources needed to satisfy state or federal public policies and slows the transition to a cleaner, more

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[109] *Id.* While carbon pricing is often touted as the most efficient means of addressing externalities related to greenhouse gases, it is not always effective at addressing the problem if issues like leakage cannot be controlled, nor is carbon pricing the only economically efficient means of doing so. *Id.*
[110] *Id.* at 16–17.
[111] *Id.* at 5–6, 17–18.
[112] Brattle Aff. at 4; Brattle PJM Aff. at 15.

advanced resource mix. Ignoring out-of-market revenues also undermines the integrity of the capacity market because the set of resources selected in market auctions do not reflect the lowest-cost or most efficient means of ensuring resource adequacy. The capacity market thus becomes a mechanism for propping up prices and protecting incumbent generators that tend to be old, inefficient, and highly polluting. Market rules that establish administratively-determined prices to negate out-of-market revenues are inefficient and anti-competitive. Advocates for applying the MOPR to state policy resources inaccurately characterize the low market prices of such resources as reflecting inappropriate "price suppression" that threatens the long-term capacity market supply and propose applying a MOPR to policy resources in order to "correct" market pricing signals.[113]

That the FCM consequently produces lower prices is not a system reliability alarm that needs to be corrected;[114] rather, the market's current low prices correctly reflect that there is an oversupply of capacity in the market and correctly signals that the least valuable resources in the market—in this case, expensive fossil fuel generators who will be utilized in the energy market with decreasing frequency—should retire.[115] In the face of years of excess supply in ISO-NE,[116] the argument that a MOPR is necessary now to prevent the possibility of insufficient capacity in

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[113] Brattle Aff. at 4; *ISO-NE*, 173 FERC ¶ 61,161, at P 56.

[114] As discussed further in Section IV.A.3.e below, to the extent there may be reliability concerns, particularly during the winter, in the ISO-NE market that are associated with gas resources lacking firm fuel supply, this is not due to low prices in the capacity market, which have persisted even with application of the MOPR, nor will they be cured by keeping state policy resources out of the capacity market. Rather, such a resource-specific problem should be handled with a resource-specific solution, rather than by overcharging customers for the entire capacity fleet and keeping out policy resources such as offshore wind, which perform well in winter. The MOPR in not an effective or efficient way of addressing the ISO's reliability concerns. *See* Brattle Aff. at 7–9.

[115] Brattle PJM Aff., at 18–20.

[116] For example, FCA 16 cleared an excess of 1,165 MW. Chadalavada Direct at 34. Excess capacity in 2021 was estimated to cost consumers $156 million. *See,* Grid Strategies, *Too Much of the Wrong Thing: The Need for Capacity Market Replacement or Reform* 6, App. A (Nov. 2019), https://gridprogress.files.wordpress.com/2019/11/too-much-of-the-wrong-thing-the-need-for-capacity-market-replacement-or-reform.pdf.

the future ignores the fundamental tenets of market theory, namely, that if supply becomes constrained in the face of increased demand, prices will rise to encourage greater investment.[117] The idea that the MOPR will "correct" the market by artificially raising the prices of the most competitive resources in the system in order to prop up the least valuable generators stands elemental market economics on its head. Instead, the MOPR forces policy resource prices higher and often out of the capacity market, even though ISO-NE acknowledges that state policy resources will be built and will operate on the system.[118] In doing so, it drives capacity prices higher, reflecting "a fictional 'need' for capacity, causing consumers to pay real money and frontline communities to face real environmental harms for real capacity resources to fill that fictional need."[119] This in turn sends the wrong signals to investors to retain costly existing resources that would otherwise retire, attracts additional resources that are not needed for reliability, and sends signals to customers to scale back on electricity use due to artificially high prices and fictional scarcity—all of which depart entirely from the fundamentals of supply and demand.[120]

The absurdly inefficient, unreasonable, and unsustainable nature of the MOPR becomes especially apparent when evaluated in the context of the ISO-NE footprint, where **90% of customer demand is within states that have adopted some of the most ambitious clean energy requirements in the nation and whose policy resources could be excluded partially or entirely by the MOPR.**[121] Continued application of the MOPR in ISO-NE would quickly turn the FCM into a "multi-billion-dollar-per-year parallel 'shadow market' that exists primarily

[117] Brattle PJM Aff., Attach. A at 19–20.
[118] Transmittal Letter at 5.
[119] Brattle PJM Aff. at 19.
[120] *Id.*
[121] *Id.* at 19. Ninety percent figure taken from Load Zone Breakdown set forth in the 2021 Forecast Itemization, https://www.iso-ne.com/static-assets/documents/2021/05/forecast_21_itmzd.xlsx.

as a means for customers to make duplicative payments to resources that are not needed for resource adequacy."[122] Such a result is the height of economic absurdity and paradigmatic of unjust and unreasonable rates.

Contrary to arguments used to support the MOPR, the "correct" price for capacity is one that aligns desired supply with actual demand, not the price and resource mix that would prevail in the absence of state policies.[123] As Drs. Spees and Newell point out:

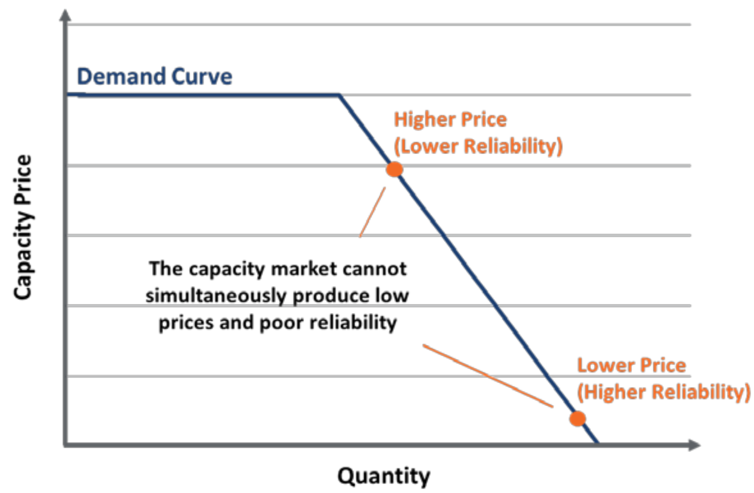
> [T]he MOPR offers a costly solution to a non-problem. The grievance from the standpoint of incumbent fossil generators is that they cannot compete and win against the clean resources that states and consumers prefer. As a consequence, fossil generation owners will earn lower revenues than they would in a world where emissions do not matter or where state policies favored their resources. Failing to earn a return on investment may be problematic for the owners of such assets, but this is not a problem that the wholesale markets can or should fix. The fix occurs when generators shift their investment portfolios toward the types of electricity resources that customers and states want to buy.[124]

4. <u>Capacity Markets with Sloping Demand Curves Cannot Simultaneously Produce Low Prices and Poor Resource Adequacy</u>

Concerns that low prices resulting from a growth in state policy resources will threaten reliability by discouraging investment are deeply misguided;[125] indeed, this concern is a mathematical impossibility.[126] By their very nature, capacity markets with downward sloping demand curves cannot simultaneously produce low prices and poor resource adequacy,[127] as reflected in the Figure 1 below:

[122] Brattle PJM Aff. at 19.
[123] Brattle Aff. at 4
[124] Brattle PJM Aff. at 19.
[125] *Id.* at 20.
[126] *Id.*
[127] Brattle Aff. at 4.

FIGURE 1: CAPACITY MARKETS WITH DOWNWARD-SLOPING DEMAND CURVES CANNOT SIMULTANEOUSLY PRODUCE LOW PRICES AND POOR RESOURCE ADEQUACY[128]



As discussed above, and reflected in the graphic above, if prices are low due to the entry of policy resources, this means that there is ample supply of capacity on the system. Low capacity prices signal that high-cost resources should retire and new entry is not needed; they do not reflect "price suppression" that demands imposition of a MOPR.[129]

Furthermore, the Commission has been abundantly clear that "low prices, in and of themselves, do not demonstrate that a market is not just and reasonable. For instance, such prices are justified in instances where a region contains substantial excess capacity unrelated to intentional uneconomic entry."[130] Low prices do not equal price suppression and should not be viewed as a problem unless they result from an exercise of market power.

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[128] Brattle PJM Aff. at 20.
[129] *Id.*
[130] *Midwest Indep. Transmission Sys. Operator, Inc.*, 153 FERC ¶ 61,229 (Nov. 20, 2015) (emphasis added).

5. Merchant Investors Operate in a Context that Includes Energy and Environmental Policies from Which They Should Not Expect to Be Indemnified

The financial woes that merchant generators and expansive MOPR proponents attribute to state policy resources resulting in lower-than-expected returns on investment, while unfortunate for them, is not a concern from a market design perspective.[131] Merchant generation investors operate in a market and regulatory context that has always required them to face uncertainties associated with energy and environmental regulations. Investors never should have expected to be indemnified against risks associated with these policies (nor should they be required to return revenues to customers when policy changes favor their investments).[132] Additionally, energy and environmental policies incentivizing a clean energy transition have been discussed in New England states for years; while some investors may have underestimated the speed and scale of this transition, no responsible investor in any power plant entering the ISO-NE capacity market can have made its investment and been unaware of the downside risks associated with states' energy and environmental policies.[133] A major purpose and oft-cited benefit of capacity markets is to shift the risk burden from consumers to investors, not the reverse, and there is no reason to indemnify investors who make poor decisions by imposing or maintaining a MOPR.[134]

Finally, recent auction results put to rest the idea that low prices and the participation of state resources will drive away merchant generator investment: despite the low clearing price ranging from $2.531 to $2.639 per kW-Month, the February 7, 2022, auction secured capacity commitments of 32,810 MW, which is 1,165 MW more than had been required to meet

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[131] Brattle PJM Aff. at 21–22.
[132] Brattle Aff. at 4.
[133] *Id.*; Brattle PJM Aff. at 21.
[134] Brattle PJM Aff. at 22.

reliability requirements, with only 256 MW of retirements and 2 MW of permanent delisting.[135] Investors unhappy with their returns can more accurately blame their merchant competitors for the low prices, rather than state policymakers. Finally, while FCA 16 did reflect a modest increase of 311 MW of new clean energy generation, the total penetration of variable resources (including demand resources) for 2025-2026 is only an extremely low 15%.[136] Even if policy resources entered the FCM without mitigation starting in FCA 17, a significant portion of capacity in ISO-NE will still be supplied by fossil resources for the foreseeable future.[137]

6. Application of the MOPR to Policy Resources Amplifies Regulatory Risks

MOPR proponents also argue that applying MOPR to policy resources is necessary to mitigate regulatory risk surrounding capacity investments.[138] They assert that "price distortions" resulting from state energy policies compromise the capacity market's "integrity" and create investor uncertainty because investors will not know whether their capital will be competing against resources that are offering into the market based on actual costs or on state subsidies, which may lead to "excessive costs to consumers as capacity sellers may include significant risk premiums in their offers."[139]

While elevated prices from a MOPR would offset some immediate issues, they "should not be conflated with less-risky prices . . . On the contrary, a market whose price is artificially inflated by a rule as controversial and economically inefficient as MOPR is unsustainable."[140]

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[135] ISO-NE, *New England's Forward Capacity Auction Closes with Adequate Power System Res. for 2025-2026*, at 1–2 (Mar. 9, 2022) ("ISO-NE FCA 16 Results Notice"), https://www.iso-ne.com/static-assets/documents/2022/03/20220309_pr_fca16_initial_results.pdf.
[136] *Id.* at 1.
[137] Analysis Group, *Pathways Study: Evaluation of Pathways to a Future Grid*, at slide 14 (Oct. 25, 2021), https://www.iso-ne.com/static-assets/documents/2022/03/fgrs_ag_2021-10-25_nepool_evaluation-of-pathways.pdf.
[138] *ISO-NE*, 173 FERC ¶ 61,161, at PP 33–39; *ISO-NE*, 162 FERC ¶ 61,205, at PP 24–25.
[139] *ISO-NE*, 173 FERC ¶ 61,161, at P 44–47.
[140] Brattle PJM Aff. at 22.

The pressure to eliminate or avoid MOPR is already well underway and will only increase as the sting of it reaches consumers already reeling from inflationary pressures, who will ask why they are paying so much for excess capacity. Investors are aware of and have expressed concerns around the uncertainty and unsustainability of ISO-NE's capacity market under the MOPR.[141] The failure of ISO-NE to accommodate state policy resources is simply unsustainable—from any perspective.[142]

As noted repeatedly by Chairman Glick, investor uncertainty that could doom capacity markets is far greater from the imposition of MOPR than it is without it.[143] Most ISO-NE state leaders view climate change as an existential threat that they must address.[144] Were ISO-NE to keep the MOPR, it would turn the capacity market into an impediment to achieving the majority of its states' widely supported and jurisdictionally permitted resource goals—a result that would actually engender far greater regulatory upheaval and investor uncertainty—and would be directly contrary to the purported desire of the Commission to foster and protect market competition.[145]

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[141] Tech. Conf. Tr. at 9, 2 (comments of Chairman Glick and Commissioner Christie regarding sustainability concerns). *See, e.g., id.* at 182–84 (Comments of Betsy Beck, Director of Regulatory Affairs – Central and Western U.S., Enel North America, Inc.); Comments of Mass. Mun. Wholesale Elec. Co., at 4–8, Docket No. AD21-10-100 (July 19, 2021); Comments of Dominion Energy Svcs. at 3–4, Docket No. AD21-10-100 (July 19, 2021).

[142] Brattle Aff. at 22–23. *See also,* NESCOE, *NESCOE Perspective Communicated to NEPOOL and ISO New England on the Minimum Offer Price Reform*, (February 8, 2022), https://nescoe.com/resource-center/mopr-perspective-2022/.

[143] *ISO-NE*, 173 FERC ¶ 61,161 (Glick, Dissenting at P 15) ("The irony, of course, is that it has been this Commission's embrace of the MOPR that has done more than anything to hasten its ultimate demise.").

[144] *See, e.g.*, NESCOE Vision Statement at 1–2*;* NESCOE Letter *New England's Regional Wholesale Elec. Mkt.s and Org. Structures Must Evolve For 21st Century Clean Energy Future*, http://nescoe.com/wp-content/uploads/2020/10/Electricity_System_Reform_GovStatement_14Oct2020.pdf; *ISO-NE*, 173 FERC ¶ 61,161 (Glick, Comm'r dissenting at P 8).

[145] Ongoing conflicts between the MOPR and state energy and environmental laws have led at least one New England energy official to question her state's participation in ISO-NE's capacity market. In January 2020, Katie S. Dykes, Commissioner of Connecticut's Department of Energy and Environmental

7. <u>MOPR Should Be Applied for Its Narrow Original Purpose of Mitigating Market Power Abuses, Not Repurposed to Undo the Effects of State Policies</u>

Clean Energy and Consumer Advocates do not dispute that the MOPR, in concept if not necessarily its current application, is an appropriate mechanism for its original purpose: prevention of manipulative price suppression by entities with buyer-side market power. But the valid rationale behind this limited form of MOPR does not apply in the context of policy-supported clean energy investments for a number of reasons: (1) state policies are pursued for the purpose of addressing a means to pursue environmental, public health, economic growth, or employment objectives, not in order to suppress market prices; (2) addressing environmental externalities is not "uneconomic"—it is a necessary market correction; and (3) applying the MOPR to state policy resources actually *causes* uneconomic behavior by incentivizing the retention of truly uneconomic, unnecessary resources.[146] As explained by Brattle:

> There is no sensible economic rationale for applying MOPR to all policy resources. States have many reasons to support capacity supply resources including to limit the harms of climate change, address environmental externalities, improve public health, create jobs, and support economic growth. The policy support awarded to such resources reflects their contributions to state policy objectives; they create environmental attributes or other benefits that states wish to buy and are remunerated for producing those benefits. Such resources are not "uneconomic" because their value is not derived from a scheme of manipulative capacity price suppression. Further, MOPR has not "leveled the playing field" because it fails to address the environmental and public health externalities that are the primary reason for most of the . . . states' policies in question. MOPR also does not attempt to undo the effects of all local, state, and federal policies that have always shaped the resource mix, including supporting

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Protection, wrote to ISO-NE's President and CEO Gordon van Welie and explained that due to the MOPR, Connecticut was "compelled to prepare contingency plans to ensure that Connecticut ratepayers and citizens are protected" including "investigating the potential options for extricating the state from the compulsory forward capacity auctions." Letter from Comm'r Katie S. Dykes to Gordon van Welie, RE: Connecticut Department of Energy and Environmental Protection, Integrated Resources Plan Proceeding, Technical Meeting (Jan. 15, 2020), https://www.iso-ne.com/static-assets/documents/2020/01/ct_deep_tech_conf_markets_jan_22_2020_isocomments.pdf.

[146] Brattle PJM Aff. at 23.

> the development of existing fossil plants and reducing the delivered cost of fossil fuels.[147]

In sum, MOPR advocates create a market solution in want of a problem, motivated primarily by a concern that incumbent fossil fuel generators may no longer expect to earn a satisfactory return on their investments.[148] While certainly a potential concern for some incumbents, low capacity prices are not a problem from a societal or market design perspective.[149] The real distortions of the FCM have come from its travels through the MOPR looking glass, not the presence of state policy resources in ISO-NE's capacity market.

C. MOPR Imposes Uneconomic Costs on ISO-NE Customers and Society As a Whole

Clean Energy and Consumer Advocates' experts analyzed the impact of applying the MOPR to state policy resources and determined that the overall effect excludes policy resources from clearing in the capacity market and has several adverse consequences, namely: (1) the MOPR will keep state policy resources from clearing the capacity market and induce the uneconomic retention of excess capacity resources; (2) the MOPR will impose costs on all ISO-NE consumers by causing them to pay higher capacity prices than is economically efficient and by requiring customers in states with policy resources to "pay twice" for capacity; (3) higher prices would effectuate a wealth transfer from customers to suppliers on the entire volume of capacity transacted in the market; and (4) supporting excess capacity results in excess societal costs or deadweight loss that benefits neither customers nor suppliers who bear the costs of maintaining the uneconomic excess supply.[150] Further, absent reform, the scale of these problems will grow along with the scope of the MOPR as New England states proceed toward

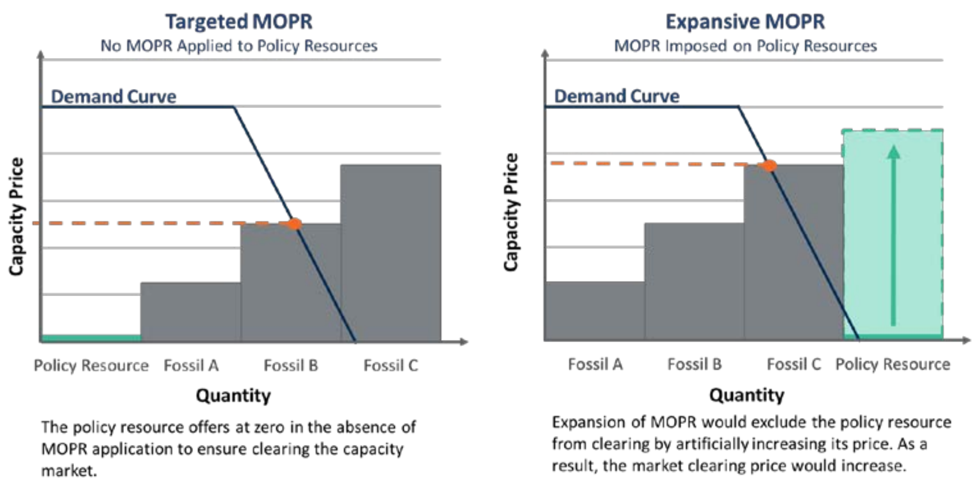
[147] *Id.* at 4.
[148] *Id.* at 19.
[149] *Id.*
[150] *Id.* at 24–25; *see also* Affidavit of Michael Goggin, at 6–7 (attached hereto as Ex. C) ("Goggin Aff.").

fulfilling their various clean energy mandates.[151] Failure to address these current and impending harms to consumers and to the ISO-NE capacity market results in rates that are unjust and unreasonable.

1. <u>Between 1,310 MW and 6,313 MW of Policy Resources Could be Excluded from Clearing the Capacity Market by 2030</u>

Applying the MOPR to state policy resources forces these resources to bid into the capacity market at administratively set prices designed to offset any benefits they receive as a result of state policies. The result is that capacity market prices increase for consumers and state policy resources are pushed out of the capacity market as depicted in Figure 2 below:

FIGURE 2: MITIGATION OF POLICY RESOURCES INCREASES THE CAPACITY CLEARING PRICE[152]



Based on a review of expected installations of capacity resources covered by New England state policies, without MOPR reform, Mr. Goggin estimates that under current state policies, **the total quantity of resources that fail to clear the FCA due to the MOPR ISO-NE-wide could be between approximately 1,310 MW and 6,313 MW of Qualified Capacity by 2030.**[153] Not all state policy resources will be precluded from clearing the capacity market.

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[151] Brattle PJM Aff. at 24–25.
[152] Brattle PJM Aff. at 13.
[153] Goggin Aff. at 10–12.

However, at default MOPR price levels, new offshore wind and imported hydropower are unlikely to clear the market.[154]

Worse yet, the FCM will seek to fill a (fabricated) gap in supply needs created by the failure of policy resources to clear by filling the fabricated gap with higher-cost Qualified Capacity from "marginal" resources that have offered at relatively high prices in the capacity market, would not otherwise clear the market, and are not needed for reliability.[155] Such excess capacity resources could be high-cost aging fossil plants that require substantial re-investments to continue operating, or they could be new gas-fired power plants that require substantial new investments to be built. Regardless of what type of capacity is built to fill the phantom supply gap, every dollar spent to bring such resources online or keep them in service is a dollar of economic waste, that leaves owners barely any better off (since every dollar earned must be spent to maintain the high-cost resource); and customers far worse off as they must pay for excess capacity that has no reliability value.[156]

2. MOPR Could Impose At Least $179 Million per Year in Excess Costs on Customers by 2030

Continuing to apply the MOPR without reform would impose a significant cost on customers across the ISO-NE region**, amounting to at least $829 million—and possibly as much as $4.1 billion—by 2030**.[157] These excess costs appear in two ways: (1) as an increase in capacity prices affecting all transactions; and (2) as an increase in contract payments to state

[154] *Id.* If some of these resources receive a lower ORTP price that allows them to clear the auction, then the true costs of MOPR could be mitigated from this estimate.
[155] Brattle Aff. at 5; Brattle PJM Aff. at 28.
[156] Brattle PJM Aff. at 28–29; Goggin Aff. at 6.
[157] Goggin Aff. at 7–11.

policy resources because they are deprived of capacity market revenues that go instead to unnecessary substitute resources.[158]

3. MOPR Imposes Excess Costs on Consumers in all States, with and without Substantial Policy Mandates.

Customers in every state across the ISO-NE footprint would bear a portion of the costs caused by continuation of the MOPR, with the largest costs imposed on customers in states whose policies support the largest MW of Qualified Capacity volume of resources excluded from clearing the auction, who will pay both higher costs for capacity purchased from the FCM and will "pay twice" for having to pay both for capacity mandated by state requirements and excluded from the FCM due to the MOPR and the excess capacity purchased to fill the "fabricated gap."[159] But even in states with no policy resources excluded, customers would face excess costs from the increased costs of capacity within the FCM due to the MOPR.[160]

4. MOPR Could Induce a Wealth Transfer from Customers to Capacity Sellers

Incumbent capacity sellers are the primary beneficiaries of the MOPR, whose excess capacity payments represent a transfer of wealth from customers. However, the net benefits that these incumbent entities would enjoy from maintaining an unreformed MOPR are below the $179 to 862 million per year by 2030 increases in costs imposed on customers, due to the deadweight losses spent to maintain aging fossil assets that would otherwise retire.[161] Thus even the net benefits to capacity suppliers as a result of the MOPR are lower than the costs to consumers.

[158] *Id.* at 6.
[159] Brattle PJM Aff. at 28.
[160] Brattle Aff. at 5–6; Goggin at 10–12. *See also*, Transmittal Letter at 29.
[161] Brattle Aff. at 5–6.

In sum, continued application of the MOPR would harm consumers more than it benefits suppliers, stands fundamental economic principles on their head, and threatens the viability of ISO-NE's capacity market. In order to ensure just and reasonable rates, as well as salvage the FCM itself, ISO-NE must abandon the decade-plus of ever-expanding MOPR application and return to the sole justifiable use of it as a narrowly focused tool whose sole function is to mitigate and prevent *actual* buyer-side market manipulation.[162]

D. The Continued Application of MOPR to State Policy Resources Threatens to Undermine the Future of Competitive Wholesale Electricity Markets

Continued application of the MOPR threatens to undermine the benefits and, eventually, the very existence of the eastern capacity markets.[163] Rates cannot justifiably ignore the connection between state policy requirements for supply and the mandatory reliability requirements of the capacity market (demand). Rates that impose the MOPR on state policy resources in order to encourage delayed exit or new entry of fossil fuel generators, while prematurely forcing out and blocking entry of the clean energy resources necessary to meet state policy requirements, disconnect the capacity market from the demand of its customers or their desired supply, and are inherently unjust and unreasonable. As explained by Brattle:

> Eventually, the scope and scale of an MOPR would become so great that it could exclude the large majority of all resources from participating, especially in states with the most ambitious climate goals. At the same time, the capacity market would continue to produce the high prices that would be necessary to retain excess capacity resources consistent with a fictional scenario as though the states' policies did not exist. This outcome is nonsensical and unsustainable. Rather than force customers to endure persistent, growing, and unnecessary excess costs, state policymakers would be forced to exit the capacity market entirely.[164]

[162] *Id.* at 7.
[163] Brattle PJM Aff. at 32–34.
[164] *Id.* at 33; *see also* ISO-NE Transmittal Letter at 31.

If capacity markets are to survive, ISO-NE and FERC must accommodate state policies that are not designed or implemented to manipulate FERC wholesale markets, but rather to accomplish legitimate state objectives.

E. There Is Widespread Agreement That ISO-NE's Tariff Must Change

There has been widespread acknowledgment from ISO-NE, New England states, the region's stakeholders, and several FERC Commissioners that ISO-NE's existing Tariff must be reformed to accommodate state policy resources and bring to an end the years of delayed auctions and litigation between ISO-NE, New England states, stakeholders, and FERC regarding the inexorable creep of its MOPR—a saga that threatens only to get worse as the vast majority of New England states transition to clean energy portfolios.

Chairman Glick and Commissioner Clements have been clear in a number of public statements and filings that existing tariffs applying mitigation policies to state policy resources are unjust and unreasonable, opining that overly broad minimum offer price rules that apply to anything besides the actual exercise of buyer-side market power "*hurts* competition" and "can lead to uneconomic price signals" with results that "distort[] the market-clearing price, and forces customers to pay more than necessary to meet their capacity needs."[165] In response to a recent ISO New England filing on FCA 16, Chairman Glick and Commissioner Clements wrote

[165] Joint Concurrence (Glick & Clements, Chairman & Comm'r, concurring). *See also* Tr. of Technical Conference on Res. Adequacy in the Evolving Elec. Sector, at 33–34, 9 (Comments of Chairman Glick), 2, 22 (Comments of Comm'r Christie), 29–30 (Comments of Comm'r Clements regarding the unworkability of the expansive MOPR), Docket No. AD21-10 (Mar. 23, 2021). *See also* Statement of Comm'r Christie, at P 2 FERC Docket No. ER21-2582-000 (Oct. 19, 2021) ("I agree that the current PJM MOPR structure needs to be replaced or significantly modified. Whatever its merits or demerits in terms of economics, I believe the incumbent PJM MOPR is simply unsustainable.").
[165] Tech. Conf. Tr. at 9.

that the existing ISO-NE Tariff "appears to be unjust and unreasonable" and admonished ISO-New England to "move expeditiously" beyond the MOPR, [166] stating:

> Such overbroad barriers are the antithesis of market competition, in that they divorce "capacity market clearing prices from the actual net going forward costs of would-be capacity suppliers" and serve "only to prop up capacity prices, protect incumbent generators, and increase the costs of State policies." The end result "is doubly bad for consumers, as they will be forced to pay for more capacity than is actually needed, and to do so at a higher price than they should, because the MOPR will allow a relatively high-cost resource to set the capacity price for the entire set of resources procured through ISO-NE's capacity market."[167]

ISO-NE's own filing provides powerful evidence of the injustice and unreasonableness of its existing Tariff. ISO-NE and its experts echo the fundamental economic tenets discussed above and repudiate the continued application of the MOPR to state policy resources. ISO-NE acknowledges that a market that precludes the entry of capacity that contributes to resource adequacy—such as state policy resources—leads to "substantial inefficiencies" resulting from inaccurate price signals regarding entry and exit necessary to maintain resource adequacy.[168] ISO-NE also acknowledges that applying the MOPR to state policy resources will price these resources out of entering the FCM and require consumers to pay twice for capacity—or what the ISO refers to as inefficient overbuild.[169] The ISO acknowledges that this inefficiency, and the resulting costs to consumers, "can threaten to overwhelm any benefit that is obtained from the de facto preclusion of higher-cost state-sponsored resources from the market" which it describes as "precisely the position New England finds itself in *today*."[170]

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[166] Joint Concurrence at P 5.
[167] *Id.* at P 4 (citations omitted).
[168] Transmittal Letter at 21–22, 27.
[169] *Id.* at 5, 21–22, 27.
[170] *Id.* at 29 (emphasis added).

Furthermore, as the last few years in particular have demonstrated, ISO-NE's various attempts to let a few state policy resources into the FCM while keeping most of them out have not improved things. As Clean Energy and Consumer Advocates and a number of parties predicted at its inception, CASPR does not actually work.[171] Even ISO-NE and its Internal Market Monitor ("IMM") admit that CASPR has failed to achieve its intended results.[172] In the four auctions since CASPR has gone into effect, only 54 MW of state policy resources having been able to gain entry, out of the over 900 MW that have attempted to enter.[173] Nor is there any expectation that CASPR's performance will improve over time or that a return to the previous limited RTR exemption would address the inefficient overbuild problem that ISO-NE identifies, given aggressive state decarbonization policies.[174] This is because, by the ISO's own admission, both the RTR exemption and CASPR were designed to preventing any impact on clearing prices in the FCM as a result of admitting state policy resources.[175] But attempting to use a minimum offer price rule as a means to prevent impacts on the FCM from state policies "is a fool's errand"[176] since "[e]lectricity markets are, and always have been, the product of public policy" and "[p]retending otherwise or trying to mitigate our way to a market free from the effects of certain public policies will only harm customers, create needless federal-state tensions, and undermine faith in the regional markets whose development has been this Commission's crowning achievement."[177]

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[171] *See, e.g.*, *ISO-NE*, 173 FERC ¶ 61,161, P 61; *ISO-NE*, 162 FERC ¶ 61,205 (Powelson, Comm'r, dissenting).
[172] Transmittal Letter at 5, 12, 28. 33.
[173] *Id.* at 28.
[174] *Id.* at 6, 12 ("[I]nefficient overbuild problem will grow and ultimately threaten[] to overwhelm the capacity market—outweighing the efficiency gains that may be obtained from application of the MOPR to state-sponsored resources.").
[175] *Id.* at 5.
[176] *ISO-NE*, 173 FERC ¶ 61,161 (Glick, Comm'r, dissenting at PP 1-2).
[177] *Id.*

In a searing indictment of its current MOPR rules, ISO-NE acknowledges that state policy resource procurements are only likely to intensify and that under the current MOPR rules a majority of the capacity in ISO-NE will be excluded from entry into the FCM.[178]

> Simply put, this situation is no longer sustainable. If the current buyer-side mitigation construct remains in place, the evidence is clear that consumers will be forced to pay for a substantial quantity of capacity twice—once 'in market' to achieve the region's resource adequacy objectives, and a second time 'out of market' for additional resources developed to meet state decarbonization policies. Given that the latter set of resources are capable of serving both objectives, it is the definition of market inefficiency to sustain a market construct that administratively precludes them from doing so."[179]

The detour away from the MOPR's original purpose has demonstrated that efforts to limit state policy impacts on the FCM only make the market less competitive, less efficient, and more costly for consumers, while also creating perpetual strife among ISO stakeholders and failing in the end to achieve the intended results. Having readily admitted the failures of the RTR exemption and CASPR to work the first time around, there is no justification for continuing to use them. That other aspects of the market may also need reform as the resource mix gradually changes to high levels of renewable penetration is undisputed,[180] but such other potential future reforms are no basis for continuing to perpetuate the MOPR's unjust, unreasonable, and unduly discriminatory pricing policies that burden consumers and frontline communities *today*. Rather,

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[178] Transmittal Letter at 30–31.

[179] *Id.*

[180] To the extent that the ISO bases its assertion that a transition period is necessary to prepare the market for high levels of penetration, it is noteworthy that ISO-NE's system currently has low levels of renewable penetration (approximately 15% including demand response), which are not anticipated to change significantly over the next decade, giving the ISO several years to prepare for a high renewable future without needing to hold up MOPR reforms. *See, e.g.*, ISO-NE FCA 16 Results Notice; Todd Schatzki, Analysis Group, *Pathways Study: Evaluation of Pathways to a Future Grid*, at 10 (Apr. 26, 2022), https://www.iso-ne.com/static-assets/documents/2022/04/ag-pathways-april-final.pdf; Evolved Energy Research, *Energy Pathways to Deep Decarbonization: A Tech. Report of the Massachusetts 2050 Decarbonization Roadmap Study*, at 6 (Dec. 2020) (noting no expectation of change in regional gas turbine fleet by 2030 in most pathways).

the complexity of the work ahead "is all the more reason to begin putting those structures in place now, rather than searching for ways to keep MOPR-based approaches on life support."[181]

IV. ISO-NE'S PROPOSAL TO DELAY MOPR REFORMS IS UNJUST AND UNREASONABLE

Unfortunately, while ISO-NE's existing MOPR is unjust and unreasonable, the ISO's proposed Delay Proposal is not a just and reasonable solution. ISO-NE proposes to keep in place its existing unjust and unreasonable MOPR for two additional capacity auctions, FCA 17 and FCA 18, and only to adopt meaningful reforms to this rule in FCA 19, which will take place in 2025 and cover the 2028–2029 capacity year. Yet as discussed below, ISO-NE fails to substantiate the need for this delay or to make a clear and convincing case as to why MOPR reforms cannot be implemented sooner, by FCA 17 in 2023 as it originally proposed. Despite MOPR's harms to consumers, ISO-NE has also failed to evaluate the consumer impacts of its proposed delay, which would continue to force consumers to pay too much for excess capacity and raise the costs of achieving state decarbonization policies in the region through at least the year 2028. Finally, ISO-NE's proposal to provide a "transition" to its eventual MOPR reforms in FCA 19 fails to meet Commission standards for approving transition mechanisms.

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[181] *ISO*, 173 FERC ¶ 61,161 (Glick, Comm'r, dissenting at PP 1-2). *See also N.Y. Pub. Serv. Comm'n v. NYISO*, 158 FERC ¶ 61,137 (Feb. 3, 2017); Order on Compliance and Paper Hr'g, 173 FERC ¶ 61,022 (Oct. 7, 2020) (Glick, Comm'r, dissenting at P 6) ("In short, I believe that buyer-side market power mitigation rules that are not limited only to market participants with actual buyer-side market power are per se unjust and unreasonable and should be abandoned *immediately*." (emphasis added)); Statement of ISO-New England, Modernizing Electricity Market Design: Resource Adequacy in the Evolving Electricity Sector, at P 3, Docket No. AD21-10 (Mar. 19, 2021) ("*Most immediately*, the evolution of FCM necessitates examination of the Minimum Offer Price Rule (MOPR). Given the states' more active role in resource procurement and the resulting shift in the resource mix, New England must address concerns about FCM's failure to account for the capacity provided by sponsored resources that do not clear the market as a result of the application of the MOPR." (emphasis added)).

A. ISO-NE Fails to Substantiate the Need for a Delay

ISO-NE contends that reforming the MOPR in time for FCA 17 would risk the reliability of electric service in New England.[182] At the same time, the ISO acknowledges that the MOPR results in "inefficient overbuild" where state policy resources that come online and provide service cannot be counted towards the region's resource adequacy picture.[183] Because ISO-NE is asking to keep in place what is an otherwise unjust and unreasonable rate,[184] it is essential that the ISO make a well-supported case that maintaining the MOPR for the next two auctions is necessary for reliability. In other words, ISO-NE must meet its burden of proof that the Delay Proposal is necessary for capacity rates in FCA 17 and FCA 18 to be just and reasonable. It has not done so.

Reliability is important, but that does not mean that a utility receives deference on any assertion that some particular rate is needed to ensure reliability—it must provide evidence to support such assertions. Likewise, for the Commission to engage in reasoned decision-making, it cannot accept such claims at face value.[185] Here, ISO-NE has failed to provide evidence that its proposed two-year delay in reforming the MOPR is necessary for reliability. Despite the ISO's substantial analytical capabilities and unique access to data—all funded by ratepayers—the ISO's case for reliability needs contained in its filing is limited to extremely general and

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[182] Transmittal Letter at 35–36.
[183] *Id.* at 5–6.
[184] *See supra* Section III.
[185] *See TransCanada Power Marketing, Ltd. v. FERC*, 811 F.3d 1, 13 (D.C. Cir. 2015) ("'[W]hen [the Commission] chooses to refer to non-cost factors in ratesetting, it must . . . offer a reasoned explanation of how the [relevant] factor[s] justif[y] the resulting rates.'") (citing *Farmers Union Cent. Exchange v. FERC*, 734 F.2d 1486, 1502 (D.C. Cir. 1984); *PJM Interconnection, LLC*, 155 FERC ¶ 61,157 (May 10, 2016) (Bay, Comm'r, dissenting at P 94) ("[T]he talismanic invocation of reliability is, by itself, inadequate to establish reasoned decision making and just and reasonable rates. The question is not whether reliability may have improved – after all, if billions are spent on a problem, there ought to be some improvement – but whether the resulting rates are just and reasonable.").

speculative concerns about capacity accreditation, retirement of existing resources, and potential commercial-operation delays applicable to all new entry in the region. The ISO admits that its proposed package ... is not contingent upon completion of either of those market reforms or filings" since "it is simply not possible to guarantee…[that they] will be completed for FCA 19."[186] If the proposal is not contingent on these changes, then the claim that they are needed for reliability does not hold. Further, ISO-NE's concerns are so vague and so unsubstantiated that they could easily be renewed in two years' time to further delay full reform of MOPR. Accepting a reliability case that is this amorphous would set a dangerous precedent that would prevent the New England region from moving towards a decarbonized grid consistent with the adopted laws and policies of the overwhelming majority of New England states.

Finally, we note that the ISO overlooks how the existence of a temporary transition mechanism could shape market participants' behavior in ways that exacerbate the very resource adequacy problems it claims exist.

1. ISO-NE Has Not Established That There Will Be Reliability Problems Without A Two-Year Delay In Reforming The MOPR

a. ISO-NE Presents No Analysis In Support Of Its Reliability Assertions

ISO-NE has not presented any analysis sufficient to support its assertion that immediate MOPR reforms would result in reliability issues due to "inefficient retirements."[187] Instead, ISO-NE claims that such an analysis cannot be done with "any level of accuracy." According to ISO-NE Executive Vice President and Chief Operating Officer Vamsi Chadalavada, it is not "possible to quantify the risk of inefficient retirements, in terms of the likely capacity that would

[186] Chadalavada Direct at 45:1–4, 14–15; Transmittal Letter at 41.
[187] The concept of inefficient retirements itself evades definition—inefficient retirements are simply retirements of resources that ISO-NE believes are valuable to the system today, or might be off in the future, but do not actually earn sufficient revenue to justify continuing to operate. *See infra*.

retire and specific adverse reliability events that would ensue with those retirements."[188] It boggles the mind that an organization with the resources of ISO-NE, and which has warned of the "inefficient retirement" problem—under one name or another—for the last decade,[189] is incapable of any sort of analysis of the risk of retirements or the adverse reliability events that might ensue. This assertion elides the fact that ISO-NE has done numerous studies in recent years that examine the reliability impacts of the changing resource mix, none of which have shown that the kinds of state policy resources that would be excluded by the MOPR heighten reliability risks.[190] ISO-NE does not explain why any of these other tools or models would not be adequate to examine the question at hand.

The first element one would expect from the ISO is a description of the characteristics of plants that might inefficiently retire, or some substantiation that these resources are particularly vulnerable to retirement. Dr. Chadalavada states that because the ISO does not have access to the information that informs the complex and idiosyncratic decisions by generation resources to retire, it cannot "estimate with any degree of accuracy the likely timing or pace of individual resources' retirement decisions."[191] If this is so, then the ISO cannot credibly assert, as it does, that "[a]llowing significant quantities of state-sponsored resources to enter the market

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[188] Chadalavada Direct at 17–18.
[189] *See, e.g.*, *ISO-NE*, 164 FERC ¶ 61,003, at P 2 (July 2, 2018) ("…[ISO-NE's] Tariff fails to address specific regional fuel security concerns identified in the record that could result in reliability violations as soon as year 2022."); *see also*, ISO-NE, *Operational Fuel-Security Analysis* ("OFSA"), at 6 (Jan. 17, 2018) ("ISO-NE OFSA"), https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf ("On multiple occasions in recent winters, the ISO has had to manage the system with uncertainty about whether power plants could arrange for the fuel—primarily natural gas—needed to run."); ISO-NE, *NEPOOL Participants Committee Report*, at 13, 15 (Apr. 2022) https://nepool.com/wp-content/uploads/2022/03/NPC_2022.04.07_5a_COO_Report_Full.pdf.
[190] *See* Test. of Abigail Krich on Behalf of Acadia Center, Conservation Law Foundation, Environmental Defense Fund, Natural Resources Defense Council, Renew Northeast, Sierra Club, and Sustainable FERC Project, at 34:3–10, 26–28 (Apr. 21, 2022) ("Krich Direct") (discussing OFSA and NEWIS studies) (attached hereto as Ex. A).
[191] Chadalavada Direct at 18.

unmitigated is, in the short-term, likely to impact the clearing price in a manner that could lead to the premature retirement of resources that have important reliability benefits for the region."[192] The ISO cannot assert a risk of inefficient retirement as the basis for a two-year delay in eliminating a market rule that it admits results in inefficient overbuild, and then claim ignorance as to the mechanisms or extent of the problem that it asserts exists.

There are several reasons why immediate MOPR reforms, implemented in FCA 17, are unlikely to cause the degree of retirements that ISO-NE is apparently concerned about. For example, in the same filing, ISO-NE describes their plans to implement within two years new day-ahead ancillary services and a significantly altered capacity accreditation scheme, both of which are intended to better compensate resources for their reliability value.[193] A generation plant that is well-maintained, has consistent access to fuel, and is generally economic to run will stand to gain from these market rule changes, and may reasonably choose to weather a couple of years of lower FCM revenues for those improved prospects. ISO-NE also suggests that capacity prices could go up in some zones as a result of MOPR elimination, after an initial wave of retirements.[194] This suggestion comports with the well-understood dynamic that prices tend towards an equilibrium in forward capacity markets. Thus, relatively efficient resources (presumably the ones ISO-NE would rather not retire) are again likely to wait out a low period of revenues for an anticipated rebound in prices after other less-efficient plants retire. ISO-NE ignores all of these dynamics in its simplistic assumption that resources it deems desirable (from a reliability perspective) will necessarily retire as a result of temporarily lower prices. Nor does ISO-NE address the possibility that the resources that would choose to exit may be those that

[192] Transmittal Letter at 36.
[193] *Id.* at 41.
[194] *Id.* at 44 n.163.

offer relatively little reliability benefit during the critical winter peak events due to dependence on limited availability pipeline gas deliveries.[195] Other resources that might retire are those that are older and more prone to breaking down under extreme conditions due to reduced maintenance and upkeep. ISO-NE offers absolutely nothing to suggest that the resources that would retire are those "whose flexibility, dependability, and/or sustainability may be far more valuable in the future."[196]

Finally, ISO-NE offers no assessment of the quantity of "inefficient" retirements that it deems concerning. The ISO's transition proposal includes a 700 MW RTR exemption that it defends as acceptable to merchant generators and, implicitly, to states.[197] But ISO-NE does not explain whether or how the retirements that may result from this 700 MW of entry would affect reliability—and why the corresponding level of retirements is acceptable, but not a megawatt more. At one point, Dr. Chadalavada asserts that "gaps" caused by (assumed) commercial-operation delays for the 700 MW represented by the RTR exemption would be "manageable" given the projected surplus for FCA 16.[198] Given that the surplus is over 1,200 MW, ISO has articulated no *reliability* basis for limiting the RTR exemption to 700 MW, nor reconciled its assessment that 700 MW is manageable with its overarching hand-wringing about any retirement of existing resources.

[195] Chadalavada Direct at 24:6–7 (describing winter reliability changes that would arise "[i]f a rapid entry of state-sponsored resources displaces existing generation that is able to operate in extended cold conditions") and 23 (acknowledging problems with gas fleet that isn't available on the coldest days).
[196] *Id.* at 12:21–22.
[197] Transmittal Letter at 42 ("The ISO understands that representatives of many of the generating companies that rely on wholesale markets and deploy private capital affected by the entry of these resources, have generally agreed with the proposed quantity of resources in the renewed renewables exemption, and that the states contracting for these renewable resources are not opposed to this exemption value.").
[198] Chadalavada Direct at 34–36.

Rather than analysis, ISO-NE ultimately rests its reliability case on the idea that it lacks all confidence in its capacity accreditation framework.[199] For instance, Dr. Chadalavada states that he cannot quantify with accuracy the impact of any retirement decision on reliability because the "ISO does not currently have in place the necessary tools to comprehensively perform this analysis" given that it lacks a methodology to assess the reliability contributions of different resources.[200] If this is so, then ISO-NE has no factual basis to assert that MOPR cannot be fully eliminated until capacity accreditation is reformed.[201] As discussed further in Section IV.A.2, below, ISO-NE's reliance on any potential errors in its capacity accreditation framework do not support delay of MOPR reforms.

b. ISO-NE's Inefficient Retirements Theory Lacks A Factual Basis And Is Fundamentally Incompatible With Competitive Markets

ISO-NE asserts that increased state policy resource entry would result in "inefficient retirements," which it describes as "the premature retirement of resources that have important reliability benefits for the region" as a result of the lower prices that would attend market entry of state policy resources.[202] The ISO views these retirements as inefficient because the units that are retiring may be more valuable in resource adequacy terms than the units that replace them, or

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[199] *Id.* at 11:5–9 (need for transition mechanism is driven by "concern[] that the immediate entry of large quantities of state-sponsored resources could pose an unacceptable risk to the existing resources upon which the region currently relies, prompting the retirement of these resources before the point at which we are in a position to fully ascertain and account for the relative reliability benefits of the retiring resources and the new resources replacing them.").

[200] *Id.* at 18.

[201] Indeed, if ISO-NE contends that its capacity accreditation is so erroneous that it cannot permit its Forward Capacity Market to enable new entry and exit, then the obvious implication is that the entire FCM is unjust and unreasonable. ISO-NE attempts to thread this needle by asserting that the capacity market has not been under-procuring capacity under its existing rules, and that "the concern with capacity accreditation arises primarily with the shift to higher concentrations of intermittent or 'just in time' resources," which MOPR reform would facilitate. Transmittal Letter at 41 n.147. ISO-NE does not explain how high the concentrations of variable resources must be before its current accreditation framework tips over from acceptable to unacceptable, nor relate such a threshold to the changes that would occur in the resource mix if MOPR reform were achieved for FCA 17 rather than FCA 19.

[202] Transmittal Letter at 36.

may have qualities that will be needed for reliability in the future but that are presently undervalued. This concept of "inefficient retirements" rests entirely upon unfounded assumptions about the resource adequacy value and flexibility of the resources that will retire. ISO-NE's view of the problem posed by "inefficient retirements" extends well beyond the two years of its proposed transition period and the ISO contends that elimination of MOPR must be "thoughtfully implemented, so as to avoid the inefficient loss of resources that may well be necessary to reliably operate the system well into the future, as part of the transforming resource mix."[203] In support, ISO-NE also points to its 2050 Transmission Study to assert that in all examined scenarios under one of the decarbonization pathways,[204] "the dispatch of fossil-fueled generation would be necessary to achieve a load-generation balance."[205] ISO-NE's facile argument seems to be that because some (unspecified) quantity of fossil-fueled generation might be needed in 2050, it would be risky to allow any of the existing fossil-fueled resources to retire now. This is the kind of argument one would expect to hear from a vertically integrated utility seeking to continue rate recovery for a dubiously economic generation plant—not from the operator of a competitive wholesale electricity market. Simply because the system may need some kind of firm generation in 30 years' time (which could be many resource types besides fossil), does not mean that the particular plants on the system today are the only option (or that all of the existing plants will be needed for future reliability). In a competitive market, plants unable to earn sufficient revenues in the present, but with a prospect of future increased

[203] Chadalavada Direct at 17:13–15; *see also id.* at 12:19–23 ("At its core, the risk is that, without the current MOPR construct in place, entry from state-sponsored resources with low-priced offers could prompt the premature retirement of resources whose flexibility, dependability and/or sustainability may be far more valuable in the future, with high renewables penetration, than the wholesale markets currently remunerate.").
[204] Krich Direct at 32.
[205] Chadalavada Direct at 17:8–9.

revenues, may delay retirement in hopes of capturing future profits. If those prospects are too remote, the existing resources may retire and new resources that can be profitable given market design and the system needs of the future grid will enter. It is backwards reasoning—to put it mildly—to make market rules today to preserve resources that could provide services that *might* be needed nearly 30 years in the future. The role of the capacity market is to ensure resource adequacy, not to procure attributes like flexibility, which are more efficiently procured and compensated through more granular and locational markets like energy and operating reserves.[206]

In sum, while the ISO's last-minute change of position as to whether a delay in MOPR reform was needed may partially explain the utter lack of a record to support its allegation of reliability issues, it certainly does not excuse it.[207] Because the ISO did not advocate for or independently analyze such a delay during the first eight months of its stakeholder process, there was no opportunity for stakeholders to evaluate any facts or to test the ISO's assumptions.[208] Instead of rigorous analysis, ISO-NE has presented the Commission with insinuations and hand-wringing over reliability that are insufficient to meet its burden under Section 205. This cannot be sufficient to meet ISO-NE's burden to support its filing with substantial evidence.

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[206] *See, e.g.*, Tr. of the October 12, 2021 Technical Conference Regarding Energy and Ancillary Markets at 75:2–6, Docket No. AD21-10 (Oct. 12, 2021) ("We don't see that the right answer is to focus on capacity market compensation for flexibility because it's just not at the right time when we need it, and it's hard at that point to match sort of performance with what it is that was purchased.") (Dr. Nicole Bouchez, Principal Economist, Market Design for NYISO speaking).

[207] *See supra* Section IV.A.3.

[208] To the extent the ISO weighed in in writing on incumbent gas entities' delay proposal during the NEPOOL Markets Committee process, prior to its endorsement of the Delay Proposal in the January 26, 2022, memo, the ISO did so skeptically: "Transition mechanisms generally require detailed rules across multiple time periods which presents challenges given the expedited timeline . . . Implementation concerns exist as the conceptual approach would impact many ISO systems." ISO-NE, *Competitive Capacity Markets without a Minimum Offer Price Rule (MOPR): Feedback on several stakeholder conceptual approaches*, at slide 10 (Aug. 31, 2021), https://www.iso-ne.com/static-assets/documents/2021/08/a2a_iso_presentation_providing_feedback_on_stakeholder_proposals.pptx.

Finally, we note that it is highly ironic that ISO-NE would cite to the extreme weather events caused by climate change as a basis to discriminate against, and slow market entry by, the very resources that states have required the procurement of in order to reduce carbon emissions from the electric sector.[209] By trying to forestall retirements of existing resources that are primarily fossil-fueled, ISO-NE is perpetuating the very status quo that exacerbates extreme weather patterns.

2. <u>The Need For Accreditation Reform Does Not Justify Delay In Reforming The MOPR</u>

ISO-NE asserts that delays in MOPR reforms are needed because "the reliability attributes of the capacity that might exit the system, and upon which the region heavily relies and will continue to rely under a changing resource mix, are not necessarily available from the new resources that will enter the system with the MOPR's elimination."[210] According to ISO-NE, its proposed delay would enable it to develop and implement a new capacity accreditation approach over the next two years, to be implemented by FCA 19 when its proposed MOPR reforms would then finally kick in.

While Clean Energy and Consumer Advocates agree that capacity accreditation in New England needs eventual reform, this does not justify delaying MOPR reforms, which are themselves needed to address an unjust and unreasonable rule that is harming both the region's consumers and its markets.[211] ISO-NE's argument that capacity accreditation reform needs

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[209] *See* Chadalavada Direct at 23:16–24:2 ("While New England has been able to manage through the operational challenges presented during past extreme weather events, climate change presents the potential for more frequent and extreme weather conditions, including extended cold weather spells, that will further challenge the system's reliability. The increased likelihood of more frequent and extreme weather events, when paired with the retirement of the Mystic station in 2024 with on-site fuel necessitates a measured approach to major market changes to try and protect against rapid and inefficient retirements.").
[210] Transmittal Letter at 37.
[211] *See supra* Section III.

justify delaying MOPR reforms is premised on a view that particular clean energy resources are over-accredited under its current rules—and uniquely so. It also assumes that some existing resources are under-accredited. These assumptions are unsupported or in other cases, demonstrably false.

The primary effect of the MOPR reform delay would be to impede market entry by offshore wind resources, but there is no basis for asserting that offshore wind is over-accredited. A 2010 study by ISO-NE—the New England Wind Integration Study ("NEWIS")—sought to understand whether "the ISO's heuristic approach to determining qualified capacity value for onshore and offshore wind was a reasonable approximation to the effective load carrying capacity ("ELCC") value of these resource types."[212] The NEWIS study concluded that wind resources were actually under-valued (relative to an ELCC approach) at low levels of penetration—up until about 5,200 MW (nameplate) of wind was installed.[213] As explained in the Krich testimony, this means that about 3,700 MW more wind (over today's 1,500 MW installed) could become operational, while still remaining under-valued.[214] The NEWIS study further determined that the current approach to capacity accreditation would give an "overall reasonable" approximation up until 8–10 GW of wind were installed.[215] This study by ISO-NE contradicts its assertion that offshore wind is necessarily overvalued under the current accreditation at the levels that might enter in FCA 17 and FCA 18.

Importantly, offshore wind performs very well during the exact times when the New England grid is currently the most stressed—the winter. In its 2018 OFSA, ISO-NE found that

[212] Krich Direct at 26.
[213] *Id.* at 27.
[214] *Id.* at 28.
[215] *Id.* at 28–29.

renewable energy growth can enhance reliability by reducing reliance on gas.[216] Only four of the scenarios examined in that analysis did not result in any load shedding—"the common factor was an increase in the amount of supply that was not dependent on gas pipelines—i.e., either new renewables, new imports, more LNG, or some combination of these."[217] One of the best-performing cases was the one "that included a modest 1,370 MW (nameplate) of new offshore wind and 1,000 MW of new imports."[218] A follow up analysis examining sensitivities proposed by stakeholders showed that "additions of imports and wind to the grid appear to be some of the most beneficial actions the region could take to improve winter reliability."[219]

In a December 2018 memo, ISO-NE analyzed the ability of offshore wind to provide energy security and economic benefits during a late December 2017 to early January 2018 cold spell during which the region experienced "a temporary, but dramatic spike in the price of natural gas in New England, which in turn triggered heavy use of oil for electricity production and high wholesale electricity prices."[220] During this period, the ISO found that a 1,600 MW offshore wind farm would have performed at 71% of its nameplate capacity (which is higher than offshore wind would likely be accredited in the capacity market[221]), saved the region $80 million to $85 million in energy production costs, lowered average day-ahead LMPs by $11 to

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[216] ISO-NE OFSA at 5, 48.
[217] Krich Direct at 25.
[218] *Id.*
[219] *Id.* at 26.
[220] ISO-NE, *High-Level Assessment of Potential Impacts of Offshore Wind Additions to the New England Power System During the 2017-2018 Cold Spell*, at 1 (Dec. 17, 2018) ("ISO-NE Offshore Wind Analysis"), https://www.iso-ne.com/static assets/documents/2018/12/2018_isone_offshore_wind_assessment_mass_cec_production_estimates_12_17_2018_public.pdf.
[221] ISO-NE assumed a capacity factor of 30.34% for offshore wind in its recent update of Offer Review Trigger Prices for FCA 16. Joint Filing of ISO-NE and NEPOOL Regarding Offer Review Trigger Prices, Attach. I-1e, Danielle S. Powers Concentric Energy Advisors, Inc. on Behalf of ISO-NE, at 27, Docket No. ER21-1637 (Apr. 7, 2021).

$13/MWh, and displaced the need for 20% of the gas used to produce electricity during the period (as well as 4% of coal and 7% of oil use).[222]

Moreover, ISO-NE's instant filing and its statements and other filings over the years make painfully clear that most of its urgent reliability problems center around over-reliance on the gas system.[223] ISO-NE has recently indicated its intention to address the capacity value of thermal resources as part of the upcoming accreditation reform discussions.[224] This is critical because gas-only resources present possibly the most significant error in ISO-NE's current accreditation scheme. The system has 9,000 MW of gas that is solely dependent on pipeline deliveries of fuel, and as the ISO has recently explained, it cannot rely on as much as 3,700 MW of this gas-only capacity during winter events.[225] ISO-NE confirms this vulnerability in the present filing as well, noting that "gas-only resources are susceptible to unavailability of natural gas during the coldest days."[226]

Thus, it is deeply misguided for ISO-NE to assert that it must be vigilant in preventing clean energy resources like offshore wind from causing the retirement of existing resources

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[222] ISO-NE Offshore Wind Analysis at 2–6.
[223] *See, e.g.*, Chadalavada Direct at 24–25 (describing a January 2022 event in which an LNG terminal that supplies the New England region lost power); ISO Newswire, *Harsh Weather Conditions Could Pose Challenges to New England's Power System This Winter*, ISO-NE (Dec. 6, 2021) (stating that "For the past two decades, ISO New England has raised concerns about fuel supply issues and their impact on electricity supply during periods of extreme cold weather. Constraints on the natural gas pipeline system limit the availability of fuel for natural gas-fired power plants, as heating customers are served first through firm service contracts," and reporting that, during winter conditions "[n]atural-gas-fired generating capacity at risk of not being able to get fuel when needed: more than 3,700 MW."), https://isonewswire.com/2021/12/06/harsh-weather-conditions-could-pose-challenges-to-new-englands-power-system-this-winter/.
[224] *See* ISO-NE, *Updated 2022 Annual Work Plan*, at 5 (Apr. 7, 2022), https://nepool.com/wp-content/uploads/2022/03/NPC_2022.04.07_6_2022_awp_update_for_04_07_22_pc.pdf.
[225] ISO-NE, *ISO-NE's 2021/2022 Winter Outlook* (Dec. 2021), https://www.iso-ne.com/static-assets/documents/2021/12/2021-22-winter-outlook.pdf*; see also*, NEPOOL, *November 3, 2021 NEPOOL Participants Committee Meeting*, at 41 et seq., ISO-NE New England Winter Outlook 2021/2022, https://nepool.com/wp-content/uploads/2021/10/NPC_20211103_Composite4.pdf.
[226] Chadalavada Direct at 23.

because of uncertainty in their accreditation. The ISO has presented zero evidence that such a change in the resource mix will reduce reliability, rather than improve it. ISO-NE paints its skeptical approach to new entry as inherently conservative and protective of reliability, but there is no evidence to support this belief. The proposed two-year delay in reforming the MOPR is most likely to delay market entry for offshore wind and potentially imported hydropower, yet these resources have some of the strongest winter reliability contribution of any resource types.[227] As illustrated in the NEWIS, OFSA, and other studies described above, the ISO-NE system may very well be stronger as a result of swapping existing resources (either gas resources without firm gas supplies or older steam units that have sluggish response times and are frequently on outage) for these new resource types.

The events of March 29, 2022, confirm that the most pressing risks to reliability come not from entry by state policy resources, but instead by the existing gas-only generation fleet. On that day, cooler-than-expected morning temperatures led to 500 MW higher load than forecasted, yet nearly 1,100 MW of gas capacity was declared non-dispatchable and ineligible to provide real-time reserves due to a lack of scheduled gas.[228] Shortly thereafter, 840 MWs of this capacity was "directed offline by gas pipeline operators," and an additional 985 MW of non-gas supply related outages and reductions occurred, requiring ISO system operators to take "action to commit additional fast-start generation and curtail export transactions in order to maintain adequate system reserves."[229] While this is only one operational incident, it illustrates the

[227] Krich Direct at 24 ("ISO-NE's own studies show that these resources provide some of the best reliability value to the system during the cold winter conditions in which the region appears to face its greatest reliability concerns").
[228] ISO-NE, *NEPOOL Participants Committee Report*, at slides 13, 15 (Apr. 2022) https://nepool.com/wp-content/uploads/2022/03/NPC_2022.04.07_5a_COO_Report_Full.pdf.
[229] *Id.*

immediacy of the problems with gas capacity that ISO-NE overlooks in its haste to paint state policy resources as the primary source of risk on the system.

3. Concerns About Delayed New Entry Do Not Support Delaying MOPR Reform

Separate from its amorphous concerns about inefficient retirements, ISO-NE also justifies its MOPR transition on the possible "adverse impacts to reliability from delays in the development of replacement state-sponsored resources."[230] Not only does ISO-NE overstate the risks of delays in commercial operation for offshore wind projects, but it also ignores the implications of a fact it readily admits[231]—that delays in development can occur for *all* new resources, not just sponsored policy resources. ISO-NE also fails to evaluate how market mechanisms intended to prevent and address commercial operation delays would ameliorate any risk here.

a. ISO-NE Overstates The Risk Of Delays In Commercial Operation By Offshore Wind Facilities

ISO-NE's reliability concerns rely upon the improbable assumption that as much as 4,700 MW of offshore wind nameplate capacity would simultaneously fail to achieve commercial operation in time to meet its capacity supply obligations corresponding to FCA 17. The ISO's sole basis for this assertion is that no wind turbine installation vessels are currently available to support construction of the projects.[232] However, as explained in the Krich Direct, the ISO is incorrect that only Jones Act-qualified vessels can be used for wind turbine installation. As she explains, "[t]here are construction methods that legally allow a foreign-flagged installation vessel to be used for construction of an offshore wind project in the United States," which "was the

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[230] Transmittal Letter at 38.
[231] Chadalavada Testimony at 28.
[232] Transmittal Letter at 29.

method used for the two operating offshore wind projects in the United States."[233] Furthermore, "[s]hipbuilding of the turbine installation vessel for [the Revolution Wind] project has already reached the halfway mark and is on schedule to be completed by December 2023."[234]

The FCA 17 commitment period begins in June 2026, which is a full two years after Vineyard Wind's latest construction schedule shows the project will be complete, and a year after Revolution Wind is scheduled to be complete.[235] Even if some delays in these schedules are possible, it is improbable that not a single new offshore wind project will be operational by the middle of 2026.

b. Commercial-Operation Delays Do Not Affect Just State Policy Resources, So Using MOPR As A Tool To Slow Entry By Offshore Wind Is Discriminatory And Ineffective

To its credit, ISO-NE does not pretend that only state policy resources are subject to commercial-operation delays. As Dr. Chadalavada states: "[w]e have seen an unmistakable trend in New England toward opposition to the development of new energy infrastructure, whether they are large renewable resources, combined-cycle resources, or transmission projects."[236] The Commission has just recently addressed the application of ISO-NE's market rules to the delays in development of a new gas-fired plant in Killingly, Connecticut.[237]

[233] Krich Direct at 14 n.30.
[234] *Id.* at 21:14–15.
[235] *Id.* at 21:11–22:6.
[236] Chadalavada Direct at 6:11–14.
[237] *See ISO*, 178 FERC ¶ 61,130 (Feb. 23, 2022) (denying rehearing of order terminating the capacity supply obligation for the NTE Killingly power plant after the developer failed to meet critical path milestones).; *see also* John Castelluccio, *Federal regulators OK delay for Footprint Power at Salem Harbor*, The Salem News (Dec. 9, 2014), https://perma.cc/H75S-GB6D (describing delays in development of the Footprint Power, gas-fired plant, in Salem, Massachusetts); Robert Walton, *ISO-NE asks FERC to cancel capacity contract with Invenergy, putting plant at risk*, Utility Dive (Sept. 24, 2018), https://perma.cc/C63Q-QNEV (describing ISO-NE's request to FERC to cancel the capacity supply obligation of Invenergy's planned Clear River Energy Center because of delays in development).

Any <u>forward</u> capacity market presents a risk that resources which obtain supply obligations—especially new ones—will not be operational at the beginning of the commitment period. For this reason, ISO-NE's capacity market rules contain numerous provisions to address and minimize this risk, discussed further below in Section IV.A.3.c.

If these rules are inadequate to address the risks of delayed operation—which ISO-NE has not shown—then a broader solution that addresses all new entry, not just that of state policy resources, is needed to effectively tackle this problem.[238] A narrow solution that addresses concerns about only some new entry is unduly discriminatory, in contravention of Section 206 of the Federal Power Act, which prohibits undue discrimination or preference in FERC jurisdictional rates, terms or conditions. Whether discrimination or preference is undue turns on whether the relevant classes of entities are similarly situated, meaning that any differences among them are "[im]material to the inquiry at hand."[239] Here, the ISO has not articulated or supported any differences between state policy resources and non-state-policy resources in terms of the likelihood that such resources will experience commercial-operation delays, or the harms that such delays might cause, that would justify different treatment. The fact that entry by state policy resources can be easily delayed simply by postponing long-overdue reforms to the MOPR is not a material difference in terms of the risk or harms of commercial-operation delay.

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[238] Using the MOPR as a patch to address commercial-operation delays is also discriminatory among state policy resources, as it does not prevent resources like solar and battery energy storage from clearing the FCA notwithstanding application of the MOPR. *See* Krich Direct at 35:1–4 ("[T]he FCA 17 ORTP values for onshore wind, solar PV, and battery energy storage are $0.00, $0.00, and $0.789/kW-month, respectively. Onshore wind and solar are guaranteed to be able to clear their offers in FCA 17 regardless of the MOPR extension, as the clearing price cannot fall below their $0.00/kW-month ORTP. While technically it is possible that the MOPR could limit battery energy storage projects from clearing in FCA 17, in practice this appears implausible given that the lowest price at which any FCA has cleared to date is $2.001/kW-month, more than two and a half times the battery ORTP value. In short, these Sponsored Policy Resources can be confident that their offers will not be mitigated in FCA 17.").

[239] *NYISO*, 162 FERC ¶ 61,124, at P 10 (Feb. 15, 2018) (citing *Iberdrola Renewables, Inc. v. Bonneville Power Admin.*, 137 FERC ¶ 61,185 at P 62 (2011), *reh'g denied*, 141 FERC ¶ 61,233 (2012)).

Two other facts cut against the arguments the ISO offers to support its unduly discriminatory proposal to slow offshore wind entry rather than addressing the broader set of market rules that fail to discourage premature entry by all resource types. First, to the extent that the ISO is concerned about development delays in new resources, it ignores the fact that a delay or cancellation of a large, proposed gas resource with a capacity supply obligation is likely to be significantly more impactful on and problematic for the market than would be caused by such a delay in an offshore wind resource. In New England, a typical offshore wind project will be qualified for 200–300 MW of summer capacity, compared to 600 MW or more for a new gas plant. Thus, if one offshore wind project is delayed, it will leave behind a smaller reliability gap than if one large gas generator is delayed or fails.

Second, ISO-NE acknowledges in its filing that state policy resources are actually *more likely* to enter commercial service because of their state policy support and the revenues they receive from outside the FCM.[240] While this does not eliminate the possibility of project delays, procurement contracts for state policy resources may also have performance incentives or penalties that incentivize timely completion. For example, a draft power purchase agreement for a Massachusetts offshore wind procurement includes a provision for significant ”delay damages” to be paid to the utility buyer should the project not achieve commercial operation by the guaranteed commercial operation date.[241] In contrast, a new gas resource that clears the FCM but lacks other contractual obligations to come online may be less likely to reach commercial operation, leaving both a larger and potentially longer-lasting hole in the market.

[240] Chadalavada Direct at 47:7–17.
[241] *See* Mass. Clean Energy, *83C Documents: Draft PPA (National Grid)*, at § 3.2, https://perma.cc/J2GC-CD5L (last visited Apr. 20, 2022).

c. *ISO-NE Does Not Establish That Delayed Entry Of Offshore Wind Would Result In Material Resource Adequacy Problems*

Setting aside the discriminatory nature of ISO-NE's plan to address delayed development with a pricing rule, ISO-NE's explanation of how delayed commercial operation of offshore wind resources would cause resource adequacy problems relies on a strained assumption that nevertheless, contrary to the ISO's assertions, would yield a manageable and acceptable resource adequacy situation. ISO-NE explains:

> Should the MOPR's immediate elimination prompt entry into the FCM for FCA 17 of the roughly 4,700 MW (or 1,269 MW in qualified capacity) of offshore wind projects that have been awarded long-term contracts and are in various stages of development, prompting retirement of a similar quantity (in qualified capacity) of existing resources in the same timeframe, and should those new projects face delays of even a single year beyond the date at which the existing resources will retire, the existing forecasted capacity surplus from FCA 16 of 1,165 MW could result in a capacity deficit, or negative planning margin, of roughly 104 MW.[242]

These 4,700 MW of offshore wind include 1,600 MW for which contracts have not yet been approved by the Massachusetts Department of Public Utilities.[243] It is unlikely that these 1,600 MWs of offshore wind would seek to offer in FCA 17, which is to be held in less than 11 months and for a commitment period beginning in mid-2026.[244] Thus, ISO-NE's example significantly overstates the potential influx of offshore wind that could occur in FCA 17—a far more realistic estimate is 3,100 MW nameplate or 837 MW in qualified capacity, which is less than the ISO's forecasted capacity surplus. It is worth remembering as well that this surplus capacity is excess capacity above the ISO's required planning margin, which includes a buffer above the region's projected demand and is the standard around which the market and grid are

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[242] Transmittal Letter at 38.

[243] Krich Direct at 6:1–7–7:14–20, 20:1–15; Transmittal Letter at 20, Table: Pending DPU Review; *see also* Mass. Clean Energy, *83C III*, https://perma.cc/ZZ9Y-NW37 (most recent update for the 83C III procurement indicates that contract negotiation is underway) (last visited Apr. 20, 2022).

[244] Krich Direct at 20:9–19; *see also id.* at 33 (discussing ISO-NE's role in assessing whether a project is likely to meet the milestones in the critical path schedule as part of the qualification process).

planned. That is to say, none of the forecasted capacity excess of 1,165 MW is required to meet the region's resource adequacy requirement.

Even the unrealistic "worst-case scenario" offered by ISO-NE, in which all of the contracted-for offshore wind were to clear in FCA 17, and then experience delays, shows only a 104 MW shortfall.[245] On a system that recently cleared nearly 33 GW of capacity,[246] this shortfall would amount to less than a third of a percent of the overall amount of committed capacity. This is well within the range of auction outcomes that the Commission has deemed permissible—the installed reserve margin is a target, not a mandatory minimum.[247] Thus, it does not by itself establish the kind of obvious and urgent reliability problem necessitating the maintenance of an otherwise unjust and unreasonable rate.

d. ISO-NE Ignores Its Own Market Design Mechanisms To Avoid And Address The Impacts Of Commercial-Operation Delays

ISO-NE's concerns about delays in commercial operation for state policy resources are further unjustified because the ISO neglects to mention its own role in ensuring that projects will be able to meet their capacity supply obligation before offering into an FCA. As explained in the Krich testimony, new resources must demonstrate to ISO-NE that they will meet critical path milestones prior to being permitted to offer into the auction. As Ms. Krich explains, "ISO-NE is not a passive bystander that must simply watch and accept as proposed resources prematurely take on Capacity Supply Obligations for which they are unlikely to be able to deliver." She

[245] Transmittal Letter at 38.
[246] *See* ISO-NE, *New England's Forward Capacity Auction Closes with Adequate Power System Resources for 2025 –2026*, https://perma.cc/W3PU-8G5V (last visited Apr. 20, 2022).
[247] *See, e.g.*, *ISO*, 147 FERC ¶ 61,173 (May 30, 2014) ("We disagree with parties that suggest that meeting the 1-in-10 LOLE standard on average over time is unjust and unreasonable and that the demand curve must be designed to meet the 1-in-10 LOLE standard in all years."); *see also*, supra note 243 (describing the net installed capacity requirement and noting that "[t]he auction rules allow the region to acquire more or less capacity.").

"recommend[s] that ISO-NE rely on these tariff provisions to mitigate its concerns regarding project delays, rather than use the transition mechanism to preemptively exclude Sponsored Policy Resources from participating in the FCM."

ISO-NE also has mechanisms already built into its Tariff to address a potential shortfall of capacity due to commercial-operation delays, most of which it fails to mention in its filing[248] ISO-NE can terminate the capacity supply obligation of a resource if it fails to meet critical path milestones.[249] Any resulting gaps can be addressed through the ISO's Annual Reconfiguration Auctions ("ARAs").[250] As ISO-NE's website explains: "Reconfiguration auctions provide an auction-based mechanism for resources to acquire, increase, or shed all or part of their capacity supply obligations (CSOs) for the entire capacity commitment period (CCP)."[251] The ARAs "allow the ISO to procure or release capacity on behalf of load by using sloped demand curves in the auction."[252] With the sloped demand curve, a shortfall of capacity would lead to higher ARA clearing prices that would help attract either new resources with relatively short construction timelines, or existing resources that had statically or dynamically de-listed in the corresponding FCA. For example, many of the clean resources now entering the market have very short construction timelines,[253] or may be able to accelerate their development if the ARA price is right. Likewise, demand side resources such as demand response and energy efficiency—which already make up a meaningful portion of the FCA cleared capacity—are

[248] ISO-NE's filing addresses only its authority to delay the retirement of existing resources, noting that it can only be used in the case of defined local transmission security issues. Transmittal Letter at 37 n.137.
249 *See ISO-NE*, 178 FERC ¶ 61,130 (denying rehearing of order terminating the capacity supply obligation for the NTE Killingly power plant after the developer failed to meet critical path milestones).
[250] ISO-NE, *Reconfiguration Auctions*, https://perma.cc/PH4C-23Q3 (last visited Apr. 20, 2022).
[251] *Id.*
[252] *Id.*
[253] All 311 MW of new capacity that cleared in FCA 16 was small solar, batteries, or a combination of the two. ISO-NE FCA 16 Results Notice at 1.

relatively quick-to-develop and could obtain a commitment through an ARA to help fill any gap. In FCA 16, 1,540 MW of capacity dynamically de-listed.[254] A high ARA price could encourage some of these to re-enter the market and obtain a supply obligation to fill the gap.

As noted in ISO-NE's example discussed above, the potential shortfall that occurs even in a worst-case scenario with no MOPR transition is only about 100 MW. That could be easily satisfied from the supply of quick-to-develop supply and demand-side resources, and de-listed existing resources. ISO-NE's failure to discuss the potential for reconfiguration auctions to address this situation provides an incomplete picture to the Commission. ISO-NE also fails to acknowledge that in previous years, the Installed Capacity Requirement has also shrunk as the commitment period approached, due to load over-forecasting.[255] While it is uncertain whether a similar dynamic would play out in any future year, this could further diminish (or possibly eliminate) any gap caused by commercial-operation delays.

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[254] ISO-NE, *Forward Capacity Auction (FCA) 16 Results*, at 1 (May 2018), https://perma.cc/R4ZQ-246L.

[255] Historically, the final Installed Capacity Requirement ("ICR") and Net ICR for ISO-NE's capacity commitment periods have nearly always been lowered as the capacity commitment period approaches and the region's actual capacity need has come into focus—i.e., between the time that the original FCA is run 3 years in advance to the time when the final ARA is conducted just prior to the commitment period. This has been true for 11 out of the 13 capacity commitment periods for which a final ARA has been conducted thus far. The only exceptions have been for the capacity commitment periods associated with FCA 3 (2012–2013) and FCA 7 (2016–2017), which saw small increases in ICR of 108 MW and 224 MW and in Net ICR of 45 MW and 184 MW in between the FCAs and final ARAs for those periods, respectively. On average, over the 13 commitment periods for which an FCA and final ARA have been conducted (including FCA 3 and FCA 7), ICR and Net ICR both dropped by about 800 MW between the initial FCA and the final ARA, reflecting the tendency of ISO-NE's load forecast to overestimate regional capacity needs at the time of the original FCA. Most recently, in the third and final ARA for the upcoming June 1, 2022, to May 31, 2023, commitment period, ICR and Net ICR both dropped by 1,495 MW compared to the original FCA 13 values. *See* ISO-NE, *Summary of Historical Installed Capacity Requirements and Related Values* (Jan. 5, 2022), https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx.

e. More Effective And Less Discriminatory Solutions Exist To Target The Commercial-Operation Delay Problem

If there is a resource adequacy problem in the next five years (which ISO-NE has not described with any level of precision), then the remedy lies not in the "square peg" tool of delaying MOPR reform, but in changes to its qualification rules and other forward market design features to address risks of delayed entry of new projects.[256]

Most fundamentally, ISO-NE could shorten the forward period of its auction to ensure that resources that obtain supply obligations are much closer to commercial operation. This forward period made sense when ISO-NE also offered a five- or seven-year rate lock on the price in the first auction in which a resource cleared. Under those circumstances—developers were more likely to make decisions about whether to build based on whether they cleared the auction; without the price lock, developers rely more on their own long-term forecasts of market revenues, which do not depend on clearing in a specific auction prior to beginning construction.

More modest steps that would incent resources to enter the market only when ready are also available and already under discussion in New England. For example, stakeholders have been developing a proposal to modify the Non-Commercial Capacity Financial Assurance rules in order to provide a stronger incentive for resources not to enter an FCA prematurely.[257] Broader changes to the qualification rules to make them more strenuous would also help to reduce the risk of projects obtaining a capacity supply obligation that will not ultimately be able to deliver in time. ISO-NE could also eliminate the three-year capacity time out rule, which

[256] *See, e.g.*, Brattle Aff. at 7–8.
[257] *See, e.g.*, RENEW Northeast, *Concerns with the CPV Performance Based FA for Non-Commercial Capacity proposal*, at PDF p. 244 (Mar. 2, 2022), https://perma.cc/4BUG-96R4.

provides another incentive for resources to prematurely enter the FCA in order to avoid losing their place in the interconnection queue.[258]

Notably, any or all of these measures would address potential commercial operation delays that ISO-NE acknowledges can affect all resource types,[259] rather than ISO-NE's unduly discriminatory MOPR Delay Proposal, which bluntly targets only state policy resources—in particular offshore wind—and effectively assumes that these resources *will* be delayed rather than creating market rules and assurances to reduce or eliminate potential delays.

4. ISO-NE's Proposed "Solution" Doesn't Address Its Purported Reliability Concerns And May Be Counterproductive To Addressing Such Concerns

As explained above, because the problems that ISO-NE asserts require delay of MOPR reforms implicate all types of new entry, the proposed transition mechanism would not fully ameliorate the problems that ISO-NE contends exist. Likewise, because ISO-NE misapprehends the most significant shortcomings of its capacity accreditation rules, its continued application of the MOPR as a tool to block market entry of new state policy resources portends continuation of ISO-NE's dangerous overreliance on gas-only resources.

Even if one takes ISO-NE at its word regarding the reliability concerns, there are reasons to believe that the proposed transition mechanism could, perversely, actually accelerate retirements by resources that ISO-NE believes are needed for reliability. ISO-NE has sought to limit entry by state policy resources to only 700 MW through the RTR exemption and touts the "certainty" that this would provide current market participants.[260] But this ignores the fact that

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[258] *See, e.g.*, RENEW Northeast, Letter from Francis Pullaro, Executive Director, to NEPOOL Participants Committee Members and Alternates, at 5–6 (PDF pp. 1279–1280) (Feb. 2, 2022), https://perma.cc/889V-U9FE.
[259] Chadalavada Direct at 6:9–17.
[260] *See, e.g.*, *id.* at 12:6–12; Test. of Ryan McCarthy on Behalf of ISO Regarding the Transition Mechanism, at 9:17–10:1 (Mar. 31, 2022), Accession No. 20220331-5296.

the substitution auction could permit considerably more entry over FCA 17 and FCA 18.[261] While the ISO is correct that the substitution auction has largely failed to enable such entry to date, ISO-NE proposes to eliminate CASPR's substitution auction test price in FCA 17 and FCA 18 as part of the Delay Proposal. This test price was not in place during the first substitution auction held as part of FCA 13—the only one where a transaction occurred in the substitution auction. Because the test price creates an obstacle to existing resources to participate as demand in the substitution auction, elimination of the test price may increase the number of existing resources that are able to enter the substitution auction and thus increase the odds that existing generators that have obtained a supply obligation in the primary FCA will then exit through the substitution auction.[262] Under the ISO's Delay Proposal, any such transactions would be subtracted from the amount of the RTR exemption available during FCA 18, but it is possible that these transactions in FCA 17 could exceed the FCA 18 RTR exemption amount, and/or that significant additional substitution auction transactions could occur during FCA 18.[263]

Clean Energy and Consumer Advocates would view such transactions as positive from the perspective of consumers as they could reduce or eliminate the inefficient overbuild problem (though this would still come at the cost of state policy resources having to pay existing resources to exit the market, so would not fully eliminate the MOPR's consumer harms). Such

[261] *See* Krich Direct at 35 ("No cap exists on the number of megawatts that may transact in the Substitution Auction and any such transactions would carry with them precisely the same concerns the ISO describes as the basis for the delay.").
[262] *Id.* at 38.
[263] *Id.* (noting that the proponents of eliminating the test price in order to "facilitate additional CASPR participation" are three companies that collectively own 6.6 GW of qualified natural gas capacity, 1.3 GW of which is dual fuel, built between 1993 and 2004); *id.* at 39:8–13 ("In FCA 16, just over 1 gigawatt of existing generation elected to submit a Substitution Auction Demand Bid and just shy of 4 gigawatts of new SPRs elected to submit Substitution Auction supply offers. Though none of these transactions cleared in FCA 16, the interest appears to be there. If the test price is removed, the volumes that could clear in the Substitution Auction during the delay period could eclipse the RTR exemption cap, leading to the same outcome that ISO-NE stated a desire to avoid.").

transactions could also be positive from a reliability perspective if the resources exiting through the substitution auction are currently over-accredited. However, these transactions would be problematic according to ISO-NE's theory of inefficient retirement. Yet, ISO-NE's Delay Proposal not only fails to prevent these retirements but actually incentivizes them, since it creates a short window of time—before CASPR would then expire at the end of FCA 18 and be replaced by broader MOPR reforms in FCA 19—where existing generators can get a payment to exit. Thus, marginally economic resources that might have otherwise decided to remain operational (with a supply obligation or not), to see how their revenues might increase with the coming market reforms might instead decide to take their opportunity for a quick payout now in the substitution auction. If the resources that make this decision are the same resources that the ISO claims are needed to ensure reliability, then the ISO's Delay Proposal would not help to achieve reliability, but instead be counter-productive to it.

ISO-NE's Delay Proposal is counter-productive in a second way—it creates a strong incentive for some state policy resources to enter in FCA 17 even if they might have been targeting FCA 18 and are uncertain of their ability to achieve commercial operation by the FCA 17 commitment period. As the ISO acknowledges, the ORTPs for solar and batteries are so low for FCA 17 as to no longer present a barrier to these resources in that auction. However, under the ISO's Delay Proposal, there is no certainty about what those ORTP values will be in FCA 18; should any of the index values that the IMM uses to update the ORTPs in interim years rise over the next year, these resources could once again be subject to limiting ORTPs in FCA 18.[264] A reasonable solar or battery developer looking to enter the market might choose to enter early in

[264] Furthermore, because of ISO-NE's rule that resources lose a portion of their capacity interconnection rights if they don't clear an auction within three years, resources that may be blocked from clearing in FCA 18 have a particularly strong incentive to try to clear in FCA 17.

FCA 17 based on an aggressive project schedule to be assured of the lower ORTP value. Doing so would then enable that resource to participate in FCA 18 as an existing resource that would not be subject to the MOPR and a potentially higher ORTP value in that auction.[265] This is the wrong incentive when one of the ISO's core concerns is new resources entering the market prematurely and then not being able to deliver on time. In contrast, prompt reform of the MOPR would avoid creating this incentive for state policy resources to obtain a capacity supply obligation relatively early in the development process; as with the limited-time offer of compensation for exit, the MOPR delay proposal distorts the incentives of market participants in ways that could worsen the dynamics that ISO-NE believes hinder reliability.

In conclusion, the MOPR has already lost its conceptual mooring by moving from a tool to address buyer-side market power to a tool to mitigate lower offers due to out-of-market revenues from state decarbonization policies that are not exercises of buyer-side market power. ISO-NE now proposes to leave the MOPR in place on the basis that it slows new entry and covers up for an allegedly inadequate accreditation scheme. But the MOPR is an inappropriate and inadequate solution to this problem. Such a makeshift approach to reliability and market-based ratemaking does not result in rates that are just and reasonable. Rather, it harms consumers and competition, all because ISO-NE has procrastinated on broader reforms to its market that would address the root of these problems.

B. Harms to Consumers

ISO-NE's Delay Proposal is also unjust and unreasonable because it would perpetuate harms to consumers by forcing consumers to continue to pay too much for unneeded capacity

[265] If such a solar or battery resource found itself unavailable by the FCA 17 delivery year, it could seek to trade out of its FCA 17 obligation in a reconfiguration auction while still being able to participate in FCA 18 as an existing resource.

and by increasing the costs of states' decarbonization policies. ISO-NE acknowledges that these consumer impacts are one of the primary reasons that MOPR reforms are needed:

> Exclusion of state-sponsored resources from the capacity market is detrimental to consumers, as it forces them to effectively pay for capacity twice—once to meet the resource adequacy objectives of the FCM and a second time to meet the clean energy and decarbonization objectives of the states. Of course, the resources that achieve the latter objective could also serve the former objective, but for the existing buyer-side mitigation rules.[266]

Yet inexplicably and without supporting evidence (in fact, contrary to the evidence that the ISO does provide) the ISO claims that such harms to consumers have yet to materialize,[267] and that protecting consumers requires that the ISO *delay* reforms to the existing rules that force customers to "effectively pay for capacity twice."[268]

ISO-NE fails to provide any estimate of the cost to consumers of delaying MOPR reforms. Given the ISO's acknowledgement that the MOPR at least has the potential to force consumers to pay twice for capacity, the ISO's failure to provide such an estimate is inexcusable. As Michael Goggin explains in his testimony, the cost of the ISO's Delay Proposal is significant. He calculates that delaying MOPR reforms could cost consumers between $197 million and $1.35 billion across FCA 17 and FCA 18, depending on the level of state policy resources that seek to enter over the next two auctions and the potential ORTP levels for these resources.[269] ISO-NE argues that MOPR reform's cost implications for consumers may be more complicated and that delaying entry by state policy resources "limits the impacts to consumers . . .and

[266] Transmittal Letter at 21–22.
[267] *Id.* at 5.
[268] *Id.* at 22 ("Of primary importance, the Filing Parties are proposing a two-year transition to the MOPR's elimination, which is intended to help prevent adverse impacts to reliability that could result with the MOPR's immediate elimination, and prevent accompanying harms to investors and consumers.").
[269] Goggin Aff. at 8–9.

avoiding the potential for costly resource adequacy and reliability issues."[270] As Clean Energy and Consumer Advocates have explained above, the ISO has failed to substantiate these reliability concerns and as a result its claim that the Delay Proposal will avoid costs to consumers is unsupported and speculative. ISO-NE further argues that cost decreases as a result of MOPR reform are "not the only possible outcome" and that some capacity zones could see price increases if certain resources retire.[271] This argument too is speculative as the ISO has provided no analysis or evidence that entry of new state policy resources would lead to such outcomes or that new state policy resources might not, instead, displace higher cost capacity in those same zones. To the extent that certain zones are import constrained, the ISO's existing rules also already require the market to clear at a separate, higher price in those zones if the capacity within them approaches or drops below the Local Sourcing Requirement.[272] The price separation increases as the amount of local capacity falls, providing a strong incentive for capacity to remain (or enter) in that zone. This provides a higher FCA price to resources within import constrained zones, making retirements of existing resources less likely when they are needed to support reliability in the zone.

ISO-NE also calls into question whether the existing MOPR has caused consumer harms to date, ostensibly as justification for its proposal to delay the rule's reform further.[273] Yet the ISO's own filing provides evidence that the MOPR has prevented substantial levels of state policy resources from being able to participate in the market, which has almost certainly affected FCA prices and consumers' capacity payments, including by forcing consumers to pay for both

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[270] Transmittal Letter at 44.
[271] *Id.* at 44 n.163.
[272] Clean Tariff—Effective May 30, 2022, §§ III.12.2, III.12.4 (Mar. 31, 2022), Accession No. 20220331-5296.
[273] Transmittal Letter at 5 ("while there is no evidence that this potential inefficiency has harmed consumers to date, that result is clearly looming").

the excess capacity that the FCA clears and the state policy resource capacity that the market excludes. ISO-NE's filing states that in the four years that CASPR has been in place, 900 MW of state policy resources have attempted to enter the market through the substitution auction yet only 54 MW have been able to do so.[274] The ISO provides no estimate or analysis of the effect of the remaining 846 MW of resources' exclusion from the market on consumers, but it is certainly not zero. By one estimate from the New England Power Generators Association, excluding the Vineyard Wind offshore wind project alone from FCA 13 under the MOPR may have resulted in a capacity clearing price that was $0.667/kW-month higher, which will cost consumers more than $270 million in the upcoming June 1, 2022, to May 31, 2023, capacity year.[275] Even the 54 MW that was able to clear the substitution auction in FCA 13 indicates an additional cost to consumers, as this capacity likely could have brought down the FCA clearing price had it been permitted to bid into the auction without mitigation.

In sum, the MOPR's ongoing harms and the Delay Proposal's anticipated harms to consumers are real. There is evidence that the MOPR has already forced consumers to pay at least hundreds of millions of dollars more than they should have for capacity and that delaying MOPR reforms under the ISO's proposal would lead to further consumer harms of this magnitude or greater in FCA 17 and FCA 18. While consumer impacts are not the only element of the Commission's just and reasonableness review, it is unacceptable for ISO-NE to have ignored consumer impacts in its evaluation of the Delay Proposal. The ISO's attempt to deflect from this glaring omission by claiming that consumers may actually benefit from delaying MOPR reforms is wholly unsupported, speculative, and contrary to the evidence presented by

[274] *Id.* at 27.
[275] Answer of the New England Power Generators Association, Inc., at 4-5, Docket No. ER19-570-000 (Feb. 5, 2019), Accession No. 20190205-5160.

both Clean Energy and Consumer Advocates and the ISO itself. ISO-NE must be held to a higher standard when it comes to evaluating consumer impacts, and the Commission cannot find that the Delay Proposal is just and reasonable based on the faulty record and arguments that the ISO provides.

C. The Delay Proposal Fails to Meet Commission Standards for Transition Mechanisms

ISO-NE's proposed transition mechanism does not meet the standards that the Commission has articulated when approving market reform proposals that include transition mechanisms. In those cases, discussed further below, the applicant provided a reasoned analysis, supported by modeling or other evidence, to justify the proposed transition mechanism, and the purpose for such transition mechanism was to give notice to the market participants who would be directly harmed by the reform and/or to avoid market volatility to the benefit of all market participants. As also discussed below, where these criteria have not been met, the Commission has rejected proposed transition mechanisms and found such proposals to be unjust and unreasonable and/or unduly discriminatory.[276] In the case of the Delay Proposal, as discussed above, ISO-NE has provided vague and unsubstantiated claims about reliability that lack evidentiary support. ISO-NE has also failed to establish that its Delay Proposal would provide market benefits and has failed to consider at all the substantial costs that delaying MOPR reforms would impose on consumers. Consistent with prior practice, the Commission should therefore reject ISO-NE’s proposed MOPR reform delay, which is unjust, unreasonable, and unduly discriminatory.

[276] *PJM Interconnection, LLC*, 175 FERC ¶ 61,084, at P 17 (Apr. 30, 2021); *NYISO*, 158 FERC ¶ 61,064, at P 56.

Prior cases illuminate the conditions under which transition mechanisms can be appropriate pathways to broader market reforms. In *PJM Interconnection, LLC*,[277] the Commission found that a transition was appropriate because it was designed to protect participants who would be harmed. At the Commission's direction, PJM sought to define the types of demand response resources that would be adversely impacted by PJM's new notification rules, which were changed to require curtailments after a 30-minute notification, rather than two hours. Recognizing that some demand response resources that agreed to a capacity supply obligation under the previous notification could not perform with only 30-minutes notice, PJM devised a transition mechanism that would exempt these resources for a specified time period.

Next, in *ISO New England Inc.*,[278] the Commission approved a transition mechanism that would phase out, rather than abruptly terminate, the RTR exemption to the MOPR as part of ISO-NE's CASPR rule changes. ISO-NE demonstrated that a quantifiable amount of carryover MWs under the existing RTR exemption remained and, therefore, proposed to continue to make those exemption MWs available over the next three FCA cycles, from FCA 13 to FCA 15, or until the remaining exemption MWs were exhausted, whichever occurred first. In approving the RTR exemption transition mechanism, the Commission found that because "investors may have made decisions based on the continuation of the RTR exemption, the transition period will mitigate some of the negative impacts that could have resulted from abrupt termination."[279]

Similarly, in another *ISO New England Inc.* decision,[280] which the Commission issued after rejecting a previous ISO-NE filing that sought to implement pay-for-performance rules, the Commission approved an ISO-NE proposed transition mechanism that phased in a capacity

[277] *PJM Interconnection, LLC*, 149 FERC ¶ 61,264 (Dec. 19, 2014).
[278] *ISO*, 162 FERC ¶ 61,205.
[279] *Id.* at P 100.
[280] *ISO*, 147 FERC ¶ 61,172 (May 30, 2013).

performance rate. In its proposal, ISO-NE sought to link capacity revenues to resource performance during reserve deficiencies using a two-settlement process, comprised of a capacity base payment and capacity performance payment, which would be negative or positive depending upon whether the resource provided its share of capacity during scarcity conditions. In accepting ISO-NE's proposal, the Commission determined that the transition mechanism would benefit all market participants.

ISO-NE claims that the Commission's decision in *ISO New England Inc. & NEPOOL Participants Committee*,[281] is analogous to the transition mechanism in the instant proceedings. We disagree. In the *NEPOOL* case, pursuant to a Commission-initiated FPA Section 206 proceeding, ISO-NE sought to revise its FCA demand curves. As part of its proposal, ISO-NE included a transition mechanism requiring the FCA to use a demand curve that was a hybrid of the then-existing demand curves and the revised demand curves for at least three FCA cycles. ISO-NE argued that the transition mechanism was necessary for developers who had already begun developing projects based on expected values from the then-existing demand curves. Based on ISO-NE's models and assumptions evaluating the impact to the market, it determined that abruptly switching to the new demand curve would cause significant shifts in the market price from $0 to $121 million in FCA 11, from $0 to $83 million in FCA 12, and from $0 to $44 million in FCA 13.[282]

In contrast, here, ISO-NE's transition mechanism to delay reform of the MOPR for state policy resources is not supported by any analysis, modeling, or other evidence, and would be detrimental to consumers and certain market participants, namely Sponsored Policy Resources. According to the Krich Testimony, ISO-NE is solely relying on the "inefficient retirement"

[281] *ISO*, 155 FERC ¶ 61,319 (June 28, 2016).
[282] *Id.* at P 60.

theory to demonstrate that continuing to exclude state policy resources, particularly offshore wind, will make its capacity market more reliable. However, as Ms. Krich concludes, the transition mechanism will cause, rather than cure, potential resource adequacy risks,[283] making that aspect of ISO-NE's filing unjust and unreasonable. Moreover, the Krich testimony also demonstrates that ISO-NE's proposal is discriminatory as it seeks to bar renewable resources from eligibility to offer and clear in FCA 17 and FCA 18 and presumes deficiencies, such as project delays, that other resource types are permitted to cure through ISO-NE's qualification process, among others.[284]

Thus, ISO-NE's delayed MOPR transition mechanism is more akin to previous transition mechanisms that the Commission has rejected. In *PJM Interconnection L.L.C.*,[285] for example, the Commission rejected PJM's proposal to assign minimum or floor capacity values to resources whose capacity values are derived from an effective load carrying capability ("ELCC") model. The Commission held that PJM's proposal was unjust, unreasonable, and unduly discriminatory in part because the transition mechanism would discount the capacity value for newer ELCC resources despite the fact that existing ELCC resources are similarly situated.

In *New York Independent System Operator*, the Commission rejected NYISO's proposal to use a static percentage, rather than the results of a power flow analysis, to account for exports using a Locality Exchange Factor. NYISO proposed the Locality Exchange factor to address an issue that its Market Monitor identified: A generator that exports capacity from a locality is treated by NYISO's capacity market auction as being out of service, which arbitrarily increases capacity prices. Using a power flow analysis to determine the percentage of capacity from other

[283] Krich Direct at 19–21, 32–33.
[284] *Id.* at 22, 32.
[285] *PJM Interconnection, L.L.C.*, 175 FERC ¶ 61,084.

localities that it can use to replace the capacity exported from an import constrained locality, NYISO calculated a Locality Exchange Factor for each capacity zone. However, for the G-J locality, NYISO proposed a one-year transition period, during which the Locality Exchange Factor for exports from that locality to ISO-NE would be fixed at 80 percent. NYISO asserted that the transition mechanism was a result of a shareholder motion and broad stakeholder support, similar to the justification that ISO-NE uses here to argue in support of its Delay Proposal. In rejecting NYISO's transition mechanism, the Commission reasoned that the static 80 percent figure was unsupported and inconsistent with the power flow results.[286]

Likewise, Clean Energy and Consumer Advocates respectfully request that the Commission reject ISO-NE's delayed MOPR transition mechanism as it is unsupported by substantial evidence, inconsistent with Commission precedent, and unjust, unreasonable, and unduly discriminatory. Unlike in prior cases in which the Commission has approved a transition mechanism, ISO-NE's Delay Proposal is not supported by convincing evidence or equitable considerations. Given that the ISO threw its support behind the Delay Proposal only at the very end of the region's stakeholder process, after having spent eight months focused instead on developing its Markets Committee Proposal, which would implement MOPR reforms without delay, it is perhaps unsurprising that ISO-NE's Delay Proposal lacks supporting evidence or a convincing rationale. But the ISO has failed to meet its responsibility under Section 205 to demonstrate that the Delay Proposal is just and reasonable and the Commission should therefore reject it.

[286] *NYISO*, 158 FERC ¶ 61,064, at P 55.

V. REQUESTED RELIEF

A. In Order to Address Extant and Increasing Harms from Currently Unjust and Unreasonable Tariff Rates, FERC Must Direct ISO-NE to Implement MOPR Reforms by FCA 17

ISO-NE's existing Tariff provisions implementing the MOPR in New England's forward capacity market are fundamentally unjust and unreasonable. As discussed in Section III, *supra*, and in Dr. Kathleen Spees and Dr. Samuel A. Newell's and Michael Goggin's testimonies, ISO-NE's MOPR has already caused significant harm to both investors and consumers. Absent reform, as discussed in Section IV.B, *supra*, and in Michael Goggin's testimony, the MOPR will lead to still greater harms in the years ahead as states continue to implement their decarbonization laws and as the MOPR continues to result in a capacity market that ignores the reliability contributions of clean energy resources that are being brought online in accordance with these laws. The result is a market that undermines efficiency and forces consumers to pay too much for excess capacity. New England states have been raising these concerns for a decade, speaking out on behalf of their consumers and raising alarm at the growing disconnect between ISO-NE's capacity market and state laws, which is "impeding those states' legal requirements to decarbonize."[287] After multiple failed attempts to minimize the MOPR's harms, ISO-NE now

[287] NESCOE, *New England States' Vision for a Clean, Affordable, and Reliable 21st Century Reg'l Elec. Grid*, at 2 (Oct. 2020), https://yq5v214uei4489eww27gbgsu-wpengine.netdna-ssl.com/wp-content/uploads/2020/10/NESCOE_Vision_Statement_Oct2020.pdf; *see also* Compl. and Mot. to Consolidate Proceedings of NESCOE, Docket Nos. EL13-34-000 and ER12-953-001 (not consolidated), (Dec. 28, 2012), https://nescoe.com/resource-center/fcm-re-exempt-dec2012/.

concurs.[288] The ISO, New England states, and majorities of the region's stakeholders agree that the current MOPR is unsustainable and must change.[289]

Unfortunately, however, while ISO-NE acknowledges the need for MOPR reforms, it is unjustly and unreasonably proposing to delay these reforms for another three years—until 2025. As explained in Section IV, *supra*, and in Abigail Krich's testimony, the ISO has failed to substantiate and support its Delay Proposal, which would needlessly perpetuate the MOPR's harms. As Michael Goggin testifies, by keeping the MOPR in place and continuing to ignore the resource adequacy contributions of state policy resources, ISO-NE's Delay Proposal could saddle New England consumers with $197 million to $1.35 billion in excess capacity costs over the next two capacity auctions.[290]

Clean Energy and Consumer Advocates urge the Commission to reject ISO-NE's unjust, unreasonable, and unduly discriminatory proposal to delay MOPR reforms, and to exercise its Section 206 authority to direct the ISO to move forward instead with necessary, just and

[288] *See, e.g.*, Transmittal Letter at 31–32 ("Under the current buyer-side mitigation construct, it is possible, indeed likely, that a majority of the capacity in the current interconnection queue will be excluded from entry into the market. . . . Simply put, this situation is no longer sustainable. If the current buyer-side mitigation construct remains in place, the evidence is clear that consumers will be forced to pay for a substantial quantity of capacity twice—once 'in market' to achieve the region's resource adequacy objectives, and a second time 'out of market' for additional resources developed to meet state decarbonization policies. Given that the latter set of resources are capable of serving both objectives, it is the definition of market inefficiency to sustain a market construct that administratively precludes them from doing so.").

[289] *See id.* at 28 ("With the Continued Expansion of State Decarbonization Policies, the ISO's Long-Standing Buyer-Side Mitigation Rules Are No Longer Sustainable"); NESCOE, *New England States' Vision for a Clean, Affordable, and Reliable 21st Century Reg'l Elec. Grid*, at 1–2 (Oct. 2020) ("Absent fundamental changes . . . the result of the existing market structure will be that some states' ratepayers will continue to overpay for electricity, constrained by a wholesale market not aligned with a rapidly transitioning resource mix and consumer investments in clean energy and decarbonization. That is not a sustainable outcome."), https://yq5v214uei4489eww27gbgsu-wpengine.netdna-ssl.com/wp-content/uploads/2020/10/NESCOE_Vision_Statement_Oct2020.pdf; Transmittal Letter at 75 (discussing NEPOOL stakeholder votes in support of MOPR reforms at the Markets Committee and Participants Committee).

[290] Goggin Affidavit at 8–10.

reasonable MOPR reforms expeditiously, in time for FCA 17 in 2023. The ISO has acknowledged that "MOPR elimination for FCA 17 is feasible."[291] As explained in Section II.A, *supra*, ISO-NE has already developed a Tariff proposal—the Markets Committee Proposal—to accomplish such changes, and this proposal was overwhelmingly endorsed by NEPOOL stakeholders at the Markets Committee on January 11, 2022. Clean Energy and Consumer Advocates urge the Commission use its Section 206 authority *sua sponte* to direct ISO-NE to implement the Markets Committee Proposal, which has already been developed and vetted through eight months of stakeholder process in the region, as the replacement rate for the current MOPR instead of the ISO's Delay Proposal.

Under the standard articulated by the D.C. Circuit in *Western Resources*,[292] the Commission is empowered to direct ISO-NE to adopt such a replacement rate provided that three conditions are met: (1) the Commission determines that ISO-NE's proposed rate (the Delay Proposal) is unjust and unreasonable;[293] (2) the Commission determines that the ISO's existing rate (the MOPR) is unjust and unreasonable;[294] and (3) the Commission establishes that its replacement rate (the Markets Committee Proposal) is just, reasonable, and supported by substantial evidence and reasoned rulemaking.[295] As we explain further below, each of these

[291] ISO-NE, *Memo to NEPOOL Participants Comm. re: ISO Support and Preference of Transition to MOPR Elimination*, at PDF p. 200 (Jan. 26, 2022), https://www.iso-ne.com/static-assets/documents/2022/02/npc-2022-02-03-composite4.pdf.
[292] *W. Res., Inc.*, 9 F.3d at 1579–80.
[293] *Id.* at 1579.
[294] *Id. See also Emera Maine*, 854 F.3d at 25 ("Section 206 therefore imposes a 'dual burden' on FERC. *FirstEnergy, 758 F.3d at 353.* Without a showing that the existing rate is unlawful, FERC has no authority to impose a new rate. *See Fla. Gas Transmission Co. v. FERC,* 604 F.3d 636, 640–41 (D.C. Cir. 2010) (examining similar requirement under the NGA); *Sea Robin Pipeline Co. v. FERC,* 795 F.2d 182, 187 (D.C. Cir. 1986) (same)").
[295] *W. Res., Inc.*, 9 F.3d at 1579 ("*See Tennessee Gas Pipeline Co. v. FERC,* 860 F.2d 446, 456 (D.C.Cir.1988) (FERC must first determine "that the presumptively just and reasonable existing rate is no longer just and reasonable") (emphasis in original); *Sea Robin Pipeline Co. v. FERC,* 795 F.2d at 184 (FERC must find "that the existing rate is unjust or unreasonable and the proposed new rate is both just and reasonable"); *ANR Pipeline Co. v. FERC,* 771 F.2d 507, 514 (D.C.Cir.1985) (same)").

criteria can be met. As discussed in Section I, *supra*, the Commission does not need to exercise its Section 206 authority in a separate proceeding since, as part of the current Section 205 proceeding created with the ISO's filing of its Delay Proposal, the Commission may discover facts that make changes pursuant to its Section 206 authority necessary.[296]

1. <u>ISO-NE's Proposal to Delay MOPR Reforms Until FCA 19 Is Unjust and Unreasonable</u>

As explained in Section IV, *supra*, ISO-NE's proposal to delay MOPR reforms until FCA 19 is unjust and unreasonable. Clean Energy and Consumer Advocates agree with ISO-NE that the existing MOPR is unsustainable and that reforms are needed.[297] However, we strongly oppose the Delay Proposal that ISO-NE has filed as its replacement, which would maintain the region's existing, unjust, unreasonable, and unduly discriminatory MOPR for a further three years, until FCA 19 in 2025. Because the ISO's FCM secures resources more than three years in advance, delaying MOPR reforms until FCA 19 would unjustly and unreasonably perpetuate the MOPR's ongoing and growing harms until nearly the end of the decade: under the Delay Proposal, ISO-NE's capacity market would continue to ignore the reliability contributions of state policy resources such as offshore wind until the 2028–2029 capacity year.

ISO-NE has failed to meet its burden under Section 205 to show that its Delay Proposal is just and reasonable. As explained in Section IV, *supra*, and in Abigail Krich's testimony, ISO-NE claims that its delay is justified because of reliability concerns, yet the ISO has failed to produce any actual or specific analysis of the purported reliability harms that could be caused by implementing MOPR reforms "too soon." As Ms. Krich explains, the ISO's reliability claims are both poorly substantiated and implausible. Moreover, ISO-NE's proposed "solution" of delaying

[296] *Advanced Energy Mgmt. All.*, 860 F.3d at 664.
[297] Transmittal Letter at 31.

MOPR reforms may even be counterproductive to its reliability concerns because the ISO's proposed changes to CASPR could actually hasten retirements by incumbent fossil fuel resources that the ISO seeks to maintain in its market for reliability.[298]

To the extent that ISO-NE's filing identifies potential reliability problems in its markets—which might separately render the existing Tariff unjust and unreasonable—related to capacity accreditation and the timely completion of new capacity resources, it has failed to substantiate any of the following: (1) that such problems are caused by or would be exacerbated by implementing MOPR reforms sooner than FCA 19; (2) that such problems are unique to the state policy resources that would be able to participate in the FCM as a result of MOPR reforms; or (3) that the ISO's Delay Proposal would address or reduce these reliability problems.

As explained in Section IV, *supra*, and in Abigail Krich's testimony, the ISO's concerns about the failure of its capacity accreditation rules to properly value the resource adequacy contributions of individual resources are neither unique to clean energy nor, principally, a clean energy issue.[299] A pending complaint before the Commission, for example, alleges that the ISO's accreditation rules are unduly preferential and discriminatory because the rules improperly treat gas-only resources as nonintermittent, despite well-documented wintertime fuel constraints and outages at these units.[300] As a result, the ISO's existing rules over-accredit and overpay gas-only resources during the winter for reliability contributions that they are unable to provide.[301]

In the context of its Delay Proposal, the ISO raises alarms that unmitigated state policy resources could replace resources in the FCM that may have higher, but currently unrecognized

[298] Krich Direct at 37–40.
[299] *Id.* at 23–29.
[300] Compl. and Req. for Expedited Consideration, at 1–5, Docket No. EL22-42-000 (Mar. 15, 2022), Accession No. 20220315-5286; *see also* Comments of Public Interest Organizations, at 1–2, 19, Docket No. EL22-42-000 (Apr. 14, 2022), Accession No. 20220414-5132.
[301] *Id.*

(by the ISO's markets) reliability value. But as explained in Section IV.A.2, *supra*, and by Ms. Krich, the ISO has not substantiated this concern and fails to show that this would be the case. In fact, if offshore wind resources, which the ISO's own analysis show provide greater capacity value during the winter, precisely when New England's grid is most constrained, were to replace over-accredited existing gas-only resources, with their well-documented performance failures during the winter, as a result of MOPR reforms, it is entirely possible that regional reliability would increase as a result of implementing such MOPR reforms immediately.

The ISO further argues that its Delay Proposal is justified because new state policy resources may experience construction delays that could interfere with their timely entry and availability in the market. Yet as explained in Section III.C, *supra*, and in Ms. Krich's testimony, the ISO's argument is both overly narrow and paints with too broad a brush. The argument is too narrow because the ISO proposes to penalize and slow the entry of renewable energy resources only, even though the ISO itself acknowledges that *all* large energy infrastructure projects face potential risks of delay.[302] In fact, in recent years, the region has experienced several delays and cancelations of proposed new fossil capacity that had cleared in the FCM yet failed to be completed on time or at all.[303] Unlike for renewable energy, however, ISO-NE proposes no limits on the entry of new fossil resources in the FCM over the next two years.

The ISO's argument is also too broad because to support its reliability claims, ISO-NE must argue that *all* of the proposed offshore wind projects in New England will enter the market too soon and be delayed. As Ms. Krich explains, the likelihood of this occurring is remote, particularly since some of these projects are expected to come online well before FCA 17's 2026–2027 capacity year, which already provides a development buffer, since these resources

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[302] Transmittal Letter at 38.
[303] *See supra* Section IV.A.3.b.

have thus far been kept out of the market by the MOPR.[304] ISO-NE also fails to acknowledge the Tariff's existing mechanisms to address project failures and delays. Such mechanisms include a rigorous qualification process for new capacity resources and the fact that capacity auctions are conducted more than three years in advance of the delivery year, with Annual Reconfiguration Auctions ("ARAs") in subsequent years that enable new resources to come in or existing resources to bid in excess capacity to address potential shortfalls.[305]

ISO-NE attempts to soften its unjust and unreasonable Delay Proposal by proposing to allow a limited quantity of state policy resources to enter the market over the next two years—up to 300 MW in FCA 17 and 400 MW in FCA 18—under a resurrected RTR exemption. But this proposal would still unjustly and unreasonably exclude hundreds to thousands of MWs of new state policy resources from the FCM in those years. As Michael Goggin's testimony explains, excluding these resources from the market could cost consumers between $197 million and $1.35 billion in excess capacity payments in those years.[306]

In sum, the ISO's Delay Proposal is poorly justified and poorly conceived. It is unclear that the proposed delay would provide any actual reliability benefits, even as it would provide clear consumer costs. ISO-NE incorrectly blames renewable resources and potential MOPR reforms for reliability problems that are created and occur under the ISO's existing Tariff *with the MOPR in place*, and then proposes "solutions" that unfairly target and attempt to slow new renewable energy entry only, even as new and existing gas resources appear to raise the same or even greater reliability concerns. Accordingly, the Commission should reject the ISO's Delay Proposal, which is both unjust and unreasonable and unduly discriminatory and preferential.

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[304] Krich Direct at 20–22.
[305] *Id.* at 22.
[306] Goggin Affidavit at 8–10.

2. ISO-NE's Existing MOPR Is Unjust and Unreasonable

As discussed in Section III, *supra*—and undisputed by the ISO—the region's current MOPR is also unjust and unreasonable. Clean Energy and Consumer Advocates agree with ISO-NE that the region's existing MOPR is unsustainable and that previous attempts to reform the region's buyer-side mitigation rules to address their failures have been unsuccessful.[307] In particular, the ISO's adoption of CASPR, and concurrent phase out and elimination of the region's prior RTR exemption to the MOPR, has unfortunately been a step backward for the region and exacerbated the MOPR's unjust and unreasonable outcomes. The original RTR exemption facilitated entry of up to 200 MW of new state-sponsored renewables per year and, had it remained in place, may have enabled up to 800 MW of additional new renewable energy resources to enter the FCM over the past four years (FCA 13 to FCA 16). Unfortunately, CASPR did away with the RTR exception and in its place has enabled entry of only 54 MW of state policy resources over the last four years.[308] As quoted by the ISO, the IMM has concluded that "it is clear that CASPR does not provide a certain and steady rate of sponsored resource entry in the same way as the Renewable Technology Resource exemption did previously."[309]

ISO-NE further acknowledges that under the current MOPR rules, "the evidence is clear that consumers will be forced to pay for a substantial quantity of capacity twice—once 'in market' to achieve the region's resource adequacy objectives, and a second time 'out of market' for additional resources developed to meet state decarbonization policies," even though state

[307] Transmittal Letter at 5.
[308] The original RTR provided exemption space for 200 MW of new renewable resources annually. If fewer than 200 MW of renewable resources used the exemption in a given year, the remaining MWs from that year's exemption were also carried forward and made available for up to two years. Under CASPR, these carried forward RTR exemption MWs from pre-FCA 13 auctions continued to be made available until they were exhausted, but no additional annual exemption MWs were provided after FCA 12, resulting in eventual exhaustion and phase out of the RTR exemption in FCA 15.
[309] Transmittal Letter at 28 (quoting IMM Spring 2021 QMR at 15).

policy resources "are capable of serving both objectives."[310] Clean Energy and Consumer Advocates agree with ISO-NE that "it is the definition of market inefficiency to sustain a market construct that administratively precludes [state policy resources] from doing so."[311] As Mr. Goggin testifies, failing to reform the MOPR would cost consumers between $830 million and $4.1 billion over the next five capacity auctions, from FCA 17 (2026–2027) to FCA 21 (2030–2031).[312]

As ISO-NE, New England states, Clean Energy and Consumer Advocates, and numerous other stakeholders agree, ISO-NE's current MOPR must be reformed to avoid these unjust and unreasonable impacts. As explained in Section III, *supra*, and in Dr. Kathleen Spees and Dr. Samuel A. Newell's and Michael Goggin's testimonies, the MOPR's unjust and unreasonable impacts have occurred—and absent reform will continue to occur—because the rule is based on flawed economic logic that violates the basic principles of supply and demand, resulting in inflated capacity prices and uneconomic costs being borne by consumers and by society as a whole. By attempting to counteract state policy choices, the MOPR leads to *less* efficient outcomes, including the failure of the market to account for environmental externalities that state policies were designed to address.

While Clean Energy and Consumer Advocates agree with ISO-NE's conclusion that the MOPR must be reformed and largely agree with its observations on the MOPR's failures, we disagree with ISO-NE's unsupported assertion that "there is no evidence that this potential inefficiency has harmed consumers to date."[313] As we explain in Section IV.B, *supra*, ISO-NE's MOPR has already prevented clean energy resources from entering the market in previous

[310] *Id.* at 31–32.
[311] *Id.* at 32.
[312] Goggin Affidavit at 10–12.
[313] Transmittal Letter at 5.

capacity auction years, resulting in higher FCA prices and consumer costs than had these clean energy resources been allowed by market rules to displace other higher cost resources and avoid the MOPR's double payment problem. By the ISO's own calculations, in the four years that CASPR has been in place, 900 MW of state policy resources have attempted to enter the market via CASPR's Substitution Auction, yet only 54 MW of these resources have actually been able to do so.[314] It does not takes a great leap of imagination to believe that, without the MOPR in place over the last four years, many if not all the remaining 846 MW of state policy resources would have been able to enter the market, displaced other new or existing resources procured by the FCM instead, and reduced consumer costs. As a specific example, excluding the Vineyard Wind offshore wind project under the MOPR in FCA 13 is expected to cost consumers more than $270 million.[315]

For all of these reasons, ISO-NE's existing MOPR is unjust and unreasonable and must be reformed. Given this reality, merely rejecting the ISO's Delay Proposal under Section 205 would be insufficient, as this would still leave in place the region's existing MOPR which would continue to cause unacceptable harms to the market and to consumers. Accordingly, as discussed below, Clean Energy and Consumer Advocates urge the Commission not just to reject the ISO's Delay Proposal, but also to act under its Section 206 authority to ensure that ISO-NE adopts instead meaningful MOPR reforms that *are* just and reasonable by FCA 17.

3. FERC Should Require ISO-NE to Implement MOPR Reforms by FCA 17, as Endorsed by the NEPOOL Markets Committee

Clean Energy and Consumer Advocates strongly oppose ISO-NE's Delay Proposal and, for the numerous reasons discussed above, believe that the ISO's proposal is unjust and

[314] *Id.* at 27.
[315] Answer of the New England Power Generators Association, Inc., at 2–3, Docket No. ER19-570-000 (Feb. 5, 2019), Accession No. 20190205-5160.

unreasonable, in violation of Section 205 of the Federal Power Act. ISO-NE's existing MOPR, however, is *even more* unjust and unreasonable, and thus simply rejecting the ISO's proposal but leaving in place the existing MOPR is untenable. For example, whereas the Delay Proposal would enable a limited quantity of up to 700 MW of state-sponsored renewable energy to enter the market under the RTR Exemption over the next two auction years and implement broader MOPR reforms beginning in FCA 19, the status quo MOPR may not enable *any* new state policy resources to enter the market in FCA 17 and FCA 18 and, absent Tariff revisions, has no expiration date.

Thus, if the Commission rejects the Delay Proposal, it is essential that the Commission also ensure, using its Section 206 authority, that ISO-NE adopts and implements a replacement MOPR reform rate that addresses the region's unjust and unreasonable status quo. To avoid the perverse outcome of rejecting the ISO's proposal but arriving at an even worse outcome for consumers, the market, and the region, it is further essential that ISO-NE's replacement rate be implemented in time for FCA 17. Rejecting the Delay Proposal but then waiting until FCA 18 to adopt replacement reforms would mean that the region suffers from another year of the current MOPR in FCA 17 and misses out on even the modest 300 MW of state-sponsored renewable energy that the Delay Proposal would potentially enable under the RTR Exemption in that year. Accordingly, we urge the Commission to not simply reject the ISO's Delay Proposal filing but to issue a Section 206 order *sua sponte* that requires ISO-NE to adopt and implement the Markets Committee Proposal as its replacement rate for the ISO's current, unjust and unreasonable MOPR in time for FCA 17, and that provides for the necessary compliance deadlines to ensure that this implementation is achieved.

Unlike the Delay Proposal, the Markets Committee Proposal was extensively reviewed during ISO-NE's stakeholder process at NEPOOL and would be a just and reasonable path forward for the region. We have included the specific Tariff language needed to implement the Markets Committee Proposal, as developed by ISO-NE with input from stakeholders and presented at the January 11, 2022, NEPOOL Markets Committee meeting, as Exhibit D. As discussed in Section II.A, *infra*, the Markets Committee Proposal was put forward by the ISO during the NEPOOL stakeholder process and was refined over eight months of stakeholder discussions and development in the NEPOOL Markets Committee between June 2021 and January 2022. This proposal, namely the Tariff language proposed by ISO-NE and included in Exhibit D, was overwhelmingly endorsed by 74.04% of NEPOOL stakeholders, at the NEPOOL Markets Committee on January 11, 2022.[316]

Consistent with the commitment that ISO-NE made to the Commission prior to the Commission's May 25, 2021, technical conference on Modernizing Electricity Market Design, the Markets Committee Proposal requires implementation of a just and reasonable package of MOPR reforms by FCA 17.[317] As discussed in Section II.A, *infra*, the Markets Committee Proposal consists of three parts: (1) removal of the Tariff's existing MOPR and MOPR-related elements; (2) incorporation of a revised buyer-side market power review process, which would enable Sponsored Policy Resources' participation in the FCM; and (3) adjustment of the CONE

[316] Transmittal Letter at 75.

[317] Pre-Conference Statement of ISO New England, at 3, Docket No. AD21-10-000 (May 21, 2021) ("ISO will . . . begin outreach to the New England states and NEPOOL stakeholders, with the goal of developing a solution that is implementable, along with the elimination of the MOPR, in time for the seventeenth Forward Capacity Auction, for which qualification processes begin in March 2022."), Accession No. 20210526-4007; *see also*, ISO-NE, Memo to NECPUC, NESCOE, and NEPOOL on Elimination of MOPR and Maintaining Competitive Pricing (May 17, 2021) ("The ISO has stated that it will work with the New England states and NEPOOL stakeholders to make a filing with the FERC to eliminate the MOPR in time for Forward Capacity Auction (FCA) 17."), https://www.iso-ne.com/static-assets/documents/2021/05/a0_memo_on_elimination_of_mopr.pdf.

and Net CONE values used in setting the FCA 17 demand curve and other auction parameters and an update to the FCM's Performance Payment Rate based on these updated values.

As discussed below, the Markets Committee Proposal is a just and reasonable framework that would address the region's existing problematic MOPR. Consistent with *Western Resources*,[318] Clean Energy and Consumer Advocates urge the Commission to exercise its Section 206 authority *sua sponte* to direct ISO-NE to adopt the Markets Committee Proposal as its replacement rate for ISO-NE's unjust and reasonable Delay Proposal and to require that ISO-NE implement the Markets Committee Proposal's MOPR reforms in time for FCA 17.

a. The MOPR Reforms Endorsed by the NEPOOL Markets Committee Are Just and Reasonable

Unlike the Delay Proposal, the Markets Committee Proposal is a just and reasonable solution to the existing MOPR's harms. The principal difference between the two proposals is that the Markets Committee Proposal would remove and replace the region's existing MOPR starting in FCA 17—next year—whereas the Delay Proposal would keep the existing unjust and unreasonable MOPR in place for three more years, delaying removal and replacement of the MOPR until FCA 19. In other words, while the Markets Committee Proposal would promptly address and eliminate the MOPR's harms in 2023, the Delay Proposal would perpetuate these harms until 2025.

Because the Markets Committee Proposal's MOPR reforms in FCA 17 are largely the same as the reforms proposed in the Delay Proposal for FCA 19, the rationale for adopting and approving the Markets Committee Proposal is largely the same as the arguments put forward by the ISO in support of the reforms that it proposes to *eventually* implement. As in the Delay Proposal, the Markets Committee Proposal would remove the existing MOPR and MOPR-related

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[318] *W. Res., Inc.*, 9 F.3d at 1579–80.

elements from the Tariff and replace them with a new just and reasonable buyer-side mitigation construct. The removal of the existing MOPR provisions and proposed replacement buyer-side mitigation construct is the same under both proposals, except for the proposed implementation dates of FCA 19 under the Delay Proposal and FCA 17 under the Markets Committee Proposal.

Under the Markets Committee Proposal, the ISO would continue to have authority to evaluate FCA bids to identify potential exercise of buyer-side market power and to mitigate bids if needed to address such buyer-side market power. Clean energy resources developed under states' decarbonization laws, however, would be exempt from this review because development of these resources is not an exercise of buyer-side market power. These resources are being developed for legitimate state policy goals, including decarbonization, not for the purpose of lowering FCA prices.

As ISO-NE recognizes, New England states' adopted clean energy policies and mandates "are, expressly by their terms, intended for the purpose of achieving state decarbonization mandates."[319] Because states' decarbonization laws are not "expressly intended to reduce prices in the Forward Capacity Market,"[320] subjecting resources built in accordance with these laws to buyer-side market power mitigation is not only economically suspect but also ineffective. States' procurements of clean energy have increased in recent years in spite of the MOPR, and New England states are likely to continue adopting even more ambitious decarbonization goals, requiring further clean energy resource builds in the years ahead, to address climate change.[321] While excluding state policy resources from the FCM under the MOPR will not prevent New

[319] Transmittal Letter at 34.
[320] *Id.*
[321] *Id.* at 33.

England states from exercising their FPA-recognized authority over the generation mix, doing so has led—and would continue to lead—to consumer and other market harms.

The ISO's filing notes that excluding state policy resources from the market under the MOPR and ignoring their capacity contributions leads to "inefficient overbuild": "As these [state policy] resources will ultimately be built regardless to achieve the region's decarbonization goals, the inefficient overbuild problem will grow and ultimately threatens to overwhelm the capacity market."[322] Excluding these resources that "nonetheless contribute[] to the resource adequacy objectives of the region"[323] from the FCM causes "attendant harm to consumers, as well as to the market,"[324] including "forc[ing] consumers to pay the cost for unneeded capacity" from other sources and a market that "fail[s] to send accurate price signals about the need for new capacity and the need to maintain existing capacity."[325] Accordingly, exempting state policy resources—which are not an exercise of buyer-side market power—from buyer-side market power review is a sensible approach to protect both consumers and the market. Clean Energy and Consumer Advocates agree with ISO-NE that the proposed new buyer-side mitigation construct, including the exemption for state policy resources (referred to as Sponsored Policy Resources under the Tariff)—though not the ISO's proposal to delay its implementation until FCA 19—is "a just and reasonable balancing of consumer and investor interests"[326] that "strike[s] a reasonable balance between undermitigation and over-mitigation of new capacity resource offers in the FCM."[327]

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[322] Transmittal Letter at 6.
[323] *Id.* at 29.
[324] *Id.* at 33.
[325] *Id.* at 29.
[326] *Id.* at 32.
[327] *Id.* at 48.

As with the Delay Proposal, the Markets Committee Proposal would revise the Tariff's current definition of Sponsored Policy Resources "to ensure that the term continues to remain current as state decarbonization policies change over time, ensuring that state-sponsored resources are not inadvertently excluded from the exemption as policies change."[328] The Tariff's current definition of Sponsored Policy Resources is too narrow, including in its restriction that Sponsored Policy Resources can only result from state policies in effect on January 1, 2018. Revising this definition, including by removing the current definition's arbitrary date restriction, is necessary to "better accommodate the range of state-sponsored resources in existence today and anticipated in the future."[329] Clean Energy and Consumer Advocates agree with the ISO that the revised definition, which is the same under both the Markets Committee Proposal and the Delay Proposal, will better "encompass all federal and state-sponsored resources receiving support from federal and New England state decarbonization programs that have the force of law, both now and in the future."[330] This definition is "narrowly crafted to extend only as far as necessary to address the inefficient overbuild issue and to respect the New England states' policy choices about generation facilities that are aimed at protecting the health and welfare of their residents."[331]

The Markets Committee Proposal also contains the same adjustments to the Qualification Determination Notification requirements; adjustments to the pre-auction information filing requirements; and change to the FCA's treatment of new capacity resources that fail to provide sufficient cost workbook information when required for the IMM's buyer-side review, that are included in the Delay Proposal, but again implemented starting in FCA 17 rather than FCA

[328] Transmittal Letter at 32.
[329] *Id.* at 57.
[330] *Id.* at 58.
[331] *Id.* at 59.

19.[332] Clean Energy and Consumer Advocates agree with the ISO's rationale for including these changes, though disagree that such changes should be delayed until FCA 19 instead of implemented in time for FCA 17. We urge the Commission to direct ISO-NE to adopt these changes sooner, consistent with the Markets Committee Proposal, and as needed to justly and reasonably replace ISO-NE's existing problematic MOPR.

b. Adjustments to CONE, Net CONE, and PPR

In its Delay Proposal filing, ISO-NE notes that it may propose a future adjustment to the Net CONE value, which is used in establishing FCA demand curves and other parameters in the FCM, to account for a potentially higher cost of capital for new merchant resources in the FCM without the MOPR.[333] The ISO bases this projected need on an analysis performed by the EMM, which recommended that if MOPR reforms were implemented in FCA 17, Net CONE should increase by 16 percent in FCA 17 to account for the change in rules.[334] Apparently because the EMM's analysis focused on adjustments needed for MOPR reforms in FCA 17 (as ISO-NE originally was proposing) rather than for FCA 19, and because no similar analysis has been performed by either the ISO or the EMM for FCA 19, ISO-NE has not proposed a specific adjustment to Net CONE as part of its the Delay Proposal. In the Delay Proposal, the ISO has instead said only that it may propose a Net CONE adjustment in the future, based on as-yet performed analysis.[335]

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[332] *See generally*, Potomac Economics, *Evaluation of Changes in the MOPR on Financial Risk in New England* (Nov. 2021) ("EMM Report") (attached hereto as Ex. E), https://www.iso-ne.com/static-assets/documents/2021/11/a03a_mc_2021_11_09_10_ccm_without_mopr_emm_presentation.docx.
[333] *Id.* at 46.
[334] *Id.* at 6.
[335] Transmittal Letter at 46.

In contrast, the Markets Committee Proposal directly incorporates an adjustment to Net CONE based on the EMM's FCA 17 analysis and recommendation.[336] In its analysis, the EMM recommended a 16 percent increase in Net CONE by for FCA 17, as well as a similar increase in the FCM's PPR, to account for potentially increased financial risk for new merchant generation in an FCM without a MOPR.[337] According to the EMM, "This recommended increase in the cost of capital will allow the capacity market to facilitate investment and retirement decisions that will satisfy New England's resource adequacy needs."[338] As Ms. Krich explains in testimony, these EMM-recommended adjustments were presented to and discussed with stakeholders over several months during the NEPOOL stakeholder process.[339] The adjustments are further supported and explained by the EMM.[340] The ISO directly incorporated the EMM's recommendations into its Markets Committee Proposal, resulting in proposed adjustments to CONE, Net CONE, and PPR. These proposed adjustments to market parameters, together with the rest of the ISO's Markets Committee Proposal, were endorsed by NEPOOL stakeholders at the Markets Committee on January 11, 2022.

If the Commission concludes that there is value in requiring a replacement rate that closely tracks the broadly supported Markets Committee Proposal, then it should include the proposed FCA 17 CONE, Net CONE, and PPR adjustments as part of this rate. We have included the EMM's report supporting these adjustments as Exhibit E to our filing.

Should the Commission have concerns about including the proposed CONE, Net CONE, and PPR adjustments as part of a Section 206 order to ISO-NE, however, Clean Energy and

[336] Markets Committee Proposal §§ III.13.2.4.2 (Interim Year Adjustments to CONE and Net CONE) and III.13.7.2.5 (Capacity Performance Payment Rate) (attached hereto as Ex. D); *see also* EMM Report at 6.
[337] EMM Report at 6.
[338] *Id.* at 15.
[339] Krich Direct at 45–46.
[340] *See generally* EMM Report.

Consumer Advocates would also endorse the Commission issuing a 206 order to ISO-NE that omits the CONE, Net CONE, and PPR adjustments in FCA 17 and believe that such an order would be just and reasonable. ISO-NE's existing Tariff already includes a requirement that the ISO update CONE and Net CONE at least once every three years and PPR "as needed."[341] ISO-NE most recently updated its CONE and Net CONE values for use in FCA 16, FCA 17, and FCA 18 in 2021.[342] Thus, if the Commission declines to order specific adjustments to CONE, Net CONE, and PPR as part of a Section 206 order, there are processes already established under the Tariff to ensure that these parameters will be updated in the future as necessary to account for changes in market conditions, including potential changes as a result of MOPR reforms in New England.

Under the current Tariff, the CONE and Net CONE values used in the FCM must be updated again no later than FCA 19. As the Tariff only requires that ISO-NE update CONE and Net CONE every three years, it is normal and to be expected that changes in market conditions, including changes in state and federal policies, in broader economic conditions or trends, or to provisions of the Tariff itself, will occur between updates (in this case, between FCA 16 and FCA 19). Such changes inevitably affect market economics in the intervening period between updates, but the Commission has nevertheless accepted updates to CONE and Net CONE once every three years and to PPR as needed as just and reasonable practices.[343] Should the Commission order ISO-NE to implement the bulk of the Markets Committee Proposal by FCA 17, but decline to order the ISO to adopt the proposal's CONE, Net CONE, and PPR values in

[341] Ex. D §§ III.13.2.4.2 (Interim Year Adjustments to CONE and Net CONE) and III.13.7.2.5 (Capacity Performance Payment Rate).
[342] *ISO*, 175 FERC ¶ 61,172 (May 28, 2021).
[343] *See, e.g.*, *id.* (order accepting, in part, subject to condition and directing compliance filing on ISO-NE's proposed 3-year updates to CONE and Net CONE and update to PPR).

advance of that auction, there is nothing in the Tariff that would prevent ISO-NE from filing a proposal with the Commission under Section 205 seeking to update these parameters sooner than required, should the ISO decide to do so on its own accord or at the urging of stakeholders.

c. The Markets Committee Proposal Is Achievable by FCA 17, and FERC Should Require Its Implementation Without Delay

As Abigail Krich explains in her testimony, it is feasible for ISO-NE to implement the Markets Committee Proposal by FCA 17.[344] ISO-NE has also stated that "MOPR elimination for FCA 17 is feasible."[345] ISO-NE's FCA schedule involves multiple deadlines in the year leading up to the auction itself, including deadlines for existing resources to notify the ISO of proposed retirements and delists, for submission of new capacity resource qualification packages, and for ISO review of these filings. Due to delays in FCA 16 related to litigation around FERC's approval of the ISO's termination of the Killingly Energy Center's Capacity Supply Obligation, ISO-NE has already requested—and the Commission has approved—authority for the ISO modify its FCA 17 schedule and deadlines.[346] As a result of this authority, the ISO has announced a revised FCA 17 schedule that pushes back several deadlines and will result in FCA 17 being conducted on March 6, 2023, one month later than originally planned.[347] It is possible that, if accepted by the Commission, the ISO's Delay Proposal might also require further adjustments to the FCA 17 calendar, due to changes that the Delay Proposal would make to FCA 17, though the ISO has not yet signaled whether this would be required.

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[344] Krich Direct at 40–42.

[345] ISO-NE, *Memo to NEPOOL Participants Comm. re: ISO Support and Preference of Transition to MOPR Elimination*, at PDF p. 200 (Jan. 26, 2022), https://www.iso-ne.com/static-assets/documents/2022/02/npc-2022-02-03-composite4.pdf.

[346] *ISO*, 179 FERC ¶ 61,003 (Apr. 1, 2022).

[347] ISO-NE, Forward Capacity Auction 17 Schedule (Mar. 23, 2022), https://www.iso-ne.com/static-assets/documents/2020/02/fca-17-market-timeline-2-4-2020.pdf.

In her testimony, Ms. Krich notes the delays that the ISO has already made to the FCA 17 schedule mean there is more time to finalize auction rules and accommodate rule changes in FCA 17, such as those that would be required if the Commission were to direct ISO-NE to implement the Markets Committee Proposal.[348] Ms. Krich notes that these changes are possible "while minimizing any resulting auction schedule impact."[349] Specifically, she testifies that if the Commission were to issue an order in this docket on May 27, 2022, directing ISO-NE to file Tariff changes consistent with the Markets Committee Proposal by July 28, 2022, and if the Commission accepted the ISO's filing by September 26, 2022, "ISO-NE could use the revised tariff to conduct FCA 17."[350] Ms. Krich notes that this schedule would likely require some flexibility to allow existing resources to reflect the potential Tariff changes in their permanent and retirement delist bids.[351] However, the region experienced a similar situation last year in FCA 16 with regard to the ISO-NE and NEPOOL ORTP jump ball filing (Docket No. ER21-1637), in which the IMM allowed resources to submit flexible, contingent bids based on different potential outcomes on that filing, "so a successful model for this type of flexibility is already in place."[352] In fact, Ms. Krich notes that there is more time in the FCA 17 schedule to implement MOPR reforms through such a flexible process than there was in the FCA 16 schedule to address the ORTP filing last year, so timing should not be a barrier.[353]

Ms. Krich also explains that there is sufficient time for new resource qualification in FCA 17 under the Markets Committee Proposal, provided that the ISO's compliance filing includes "a one-time provision for FCA 17" that would allow new resources to submit "certifications and

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[348] Krich Direct at 40–42.
[349] *Id.* at 40.
[350] *Id.*
[351] *Id.* at 40–42.
[352] *Id.* at 41.
[353] *Id.* at 43–45.

demonstrations that would otherwise normally be submitted along with the qualification package" by October 3, 2022 (i.e., within one week of the Commission's potential acceptance of the ISO's compliance filing on September 26, 2022). Ms. Krich notes that this one-time provision, which would be needed to accommodate the Markets Committee Proposal's new buyer-side mitigation review process, could be carried out by the ISO, IMM, and market participants "with little impact on the auction schedule" and in time for FCA 17 to take place as scheduled on March 6, 2023.[354]

Notably, there could also be substantially more time available to implement the Markets Committee Proposal changes in time for FCA 17 if the Commission were to order an expedited process under Section 206. Given that the Markets Committee Proposal is a fully developed Tariff proposal that was originally proposed by ISO-NE and has already been substantially vetted through the NEPOOL stakeholder process and endorsed by the NEPOOL Markets Committee, there should be little need for an extensive ISO-NE compliance filing in response to a Section 206 order. While an ISO compliance filing would likely still be needed to propose potential minor adjustments to the FCA 17 schedule, as discussed above, the Commission could otherwise direct ISO-NE to simply adopt the Tariff changes proposed under the Markets Committee Proposal, which have already been developed and should not require extensive time or process at the ISO to begin implementation in response to a Commission Section 206 order.

Accordingly, if the Commission agrees with Clean Energy and Consumer Advocates that the Markets Committee Proposal is a just and reasonable alternative to the unjust and unreasonable Delay Proposal and to the unjust and unreasonable existing MOPR, we suggest

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[354] Kirch Direct at 44.

requiring under its Section 206 order that ISO-NE submit a compliance filing quickly, in order to avoid further unnecessary delays in the FCA 17 schedule.

VI. CONCLUSION

For the foregoing reasons, Clean Energy and Consumer Advocates respectfully urge the Commission to (1) reject ISO-NE's Delay Proposal, which is unjust and unreasonable in violation of Section 205 of the Federal Power Act; (2) find, *sua sponte*, under its Section 206 authority that ISO-NE's Tariff is unjust and unreasonable due to the existing MOPR; and (3) direct ISO-NE under Section 206 to amend its Tariff consistent with the Markets Committee Proposal discussed above and to submit a limited compliance filing, as needed, to propose adjustments to the FCA 17 schedule to ensure that the Markets Committee Proposal rule changes are implemented in time for FCA 17.

List of Attachments:

- Exhibit A: Testimony of Abigail Krich, Boreas Renewables/RENEW Northeast on Reliability Impacts
- Exhibit B: Testimony of Dr. Kathleen Spees and Dr. Samuel A. Newell
- Exhibit C: Testimony of Michael Goggin
- Exhibit D: Tariff Language Approved by the NEPOOL Markets Committee
- Exhibit E: EMM Report

Dated: April 21, 2022. Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that the foregoing has been served in accordance with 18 C.F.R. § 385.2010 upon each party designated on the official service lists in these proceedings listed above, by email.

Dated: April 21, 2022.

/s/ Gabriela Rojas-Luna
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<u>EXHIBIT A</u>

Testimony of Abigail Krich, Boreas Renewables/RENEW Northeast on Reliability Impacts

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
ISO New England Inc.	)	Docket No. ER22-1528
	)	

TESTIMONY OF ABIGAIL KRICH

ON BEHALF OF

RENEW NORTHEAST, NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB, CONSERVATION LAW FOUNDATION, ACADIA CENTER, THE ENVIRONMENTAL DEFENSE FUND, SUSTAINABLE FERC PROJECT, MASSACHUSETTS CLIMATE ACTION NETWORK, POWEROPTIONS, E2 (ENVIRONMENTAL ENTREPRENEURS), AND AMERICAN CLEAN POWER ASSOCIATION ("CLEAN ENERGY AND CONSUMER ADVOCATES")

APRIL 21, 2022

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I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and company description.

A. My name is Abigail Krich.[1] I am the founder and president of Boreas Renewables, LLC ("Boreas"), a consulting practice serving renewable energy resource developers, owners, operators, and advocates including RENEW Northeast ("RENEW" or "RENEW-Northeast"). Founded in 2008, Boreas specializes in helping developers navigate their way through the Independent System Operator ("ISO") New England interconnection process, participate in the Forward Capacity Market ("FCM"), and register to sell into the New England wholesale electricity markets. Boreas works with energy resource owners and operators to understand how existing and upcoming market rules and compliance requirements factor into their day-to-day operations. In addition to following the evolving markets, Boreas actively advocates within the New England Power Pool ("NEPOOL") and ISO New England Inc. ("ISO-NE" or "the ISO") stakeholder process for electricity market rules and system planning improvements that will allow for the development and integration of high levels of renewable energy.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of the Clean Energy and Consumer Advocates as defined in the title above.

Q. Please summarize your relevant work experience and education.

A. Among the positions I have held in the field of renewable energy over the past nineteen years, I was a Senior Project Developer at Tamarack Energy; an independent consultant

[1] My full legal name is Abigail Krich Starr, but my professional name is Abigail Krich.

performing wind energy resource assessments; an electrical/mechanical designer at Northern Power Systems in the distributed generation project engineering group; a graduate intern at the National Wind Technology Center at the National Renewable Energy Laboratory working primarily with the grid integration group; and an intern at Berkshire Photovoltaic Services. I was elected to serve as Vice-Chair of the NEPOOL Variable Resource Working Group, which I have done since the group's inception in 2014. I have passed the Fundamentals of Engineering exam and hold a Bachelor of Science in Biological and Environmental Engineering, as well as a Master's of Engineering in Electrical and Computer Engineering, both from Cornell University.

Q. Have you testified before this Commission or as an expert in any other proceeding?

A. Yes. I list my testimony experience below:

- Testimony before the Federal Energy Regulatory Commission ("FERC" or the "Commission") regarding the NEPOOL and ISO-NE's Offer Review Trigger Price ("ORTP") proposals on April 5, 2021, in Docket No. ER21-1637-000.
- Testimony before the Commission regarding capacity factors at New England wind farms and implications for the FCM, submitted on behalf of RENEW, First Wind, and Conservation Law Foundation, on January 23, 2014, in Docket No. ER14-616.
- Testimony before the Maine Department of Environmental Protection on behalf of Conservation Law Foundation, regarding the economic and environmental impacts of wind energy in Maine, for the Champlain Wind public hearing on May 1, 2013.[2]

[2] Pre-Filed Test. of Abigail Krich on Behalf of Intervenor Conservation Law Found., Docket No. L-25800-24-25800-TE-B-N (Me. Dep't of Env't Prot. Mar. 13, 2013), https://www.boreasrenewables.com/pres/2013-03-13-Abigail%20Krich%20Testimony%20for%20CLF%20Notarized.pdf.

- Testimony before the Maine Land Use Regulation Commission on behalf of Conservation Law Foundation regarding the economic and environmental impacts of wind energy in Maine, for the Champlain Wind public hearing on June 28, 2011.[3]
- Testimony before the Maine Public Utilities Commission ("MPUC") on behalf of Highland Wind in support of Central Maine Power Company's petition to construct the Somerset County Reinforcement Project consisting of the construction of approximately 39 Miles of 115 kV transmission lines (i.e., "Section 241") before the MPUC, May 26, 2011.[4]

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain that the Commission should reject ISO-NE's proposed transition mechanism, which seeks to impose a two-year delay on exempting Sponsored Policy Resources from ISO-NE's Minimum Offer Price Rules ("MOPR") while removing the test price provision from the Competitive Auctions with Sponsored Policy Resources ("CASPR") Substitution Auction and reinstituting the Renewable Technology Resource ("RTR") exemption.

I will explain that the transition mechanism will likely exacerbate rather than mitigate reliability risks in ISO-NE's FCM by prohibiting certain Sponsored Policy Resources from clearing in the two upcoming Forward Capacity Auctions ("FCA"), encouraging

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[3] Pre-Filed Direct Test. of Abigail Krich on Behalf of the Conservation Law Found., Development Permit DP 4889 (Me. Land Use Regul. Comm'n June 10, 2011), https://www.maine.gov/dacf/lupc/projects/windpower/firstwind/champlain_bowers/Development/Application/Testimony/CLF_KrichBowersTestimony-2011-06-10.pdf.

[4] Rebuttal Test. of Abigail Krich on Behalf of Highland Wind, LLC, Docket No. 2010-00180 (Me. Pub. Util. Comm'n May 26, 2011), https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=113055&CaseNumber=2010-00180.

other Sponsored Policy Resources to enter the market prematurely, and encouraging existing resources to retire sooner than they might otherwise, among other reasons. In addition, I will explain that ISO-NE's accreditation process is sufficient for valuing the offshore wind resources that might be expected to enter the market in FCA 17 and FCA 18. Finally, I will outline schedule adjustments that will allow ISO-NE to conduct FCA 17 in the event that the Commission directs it to refile its proposal without the transition mechanism, consistent with the Clean Energy Advocates' protest.

II. TRANSITION MECHANISM PROPOSAL

Q. Please describe the transition mechanism.

A. As I described earlier, ISO-NE proposes tariff changes that will exempt, among others, new Sponsored Policy Resources from its buyer-side market power review process. However, ISO-NE proposes to delay this tariff change until FCA 19, which will award Capacity Supply Obligations for the June 2028 to May 2029 Capacity Commitment Period. In the interim, in FCA 17 and FCA 18, for the June 2026 to May 2027 and June 2027 to May 2028 Capacity Commitment Periods, respectively, ISO-NE proposes to continue performing its current buyer-side market power review, including of new Sponsored Policy Resources, with some limited exceptions.

Specifically, ISO-NE proposes to reinstitute the RTR exemption, which allows certain new Sponsored Policy Resources to bypass the market power review process. ISO-NE proposes to cap the quantity of RTR capacity that could clear in FCA 17 to 300 megawatts ("MW"). Any unused portion of this 300 MW cap would roll over and be added to the 400 MW cap proposed for FCA 18, though the FCA 18 cap would also be reduced in the amount of any transactions that cleared in the CASPR Substitution Auction associated with FCA 17.

And, finally, ISO-NE proposes to eliminate the test price rules that apply to the CASPR substitution auction in order to encourage more participation from the demand side (i.e., resources with capacity supply obligations seeking to exit).

III. STATE POLICY RESOURCES AVAILABLE FOR FCA 17 AND FCA 18

Q. How many Sponsored Policy Resources could qualify to participate in FCA 17 and FCA 18?

A. A summary of my estimates is captured in Figure 1. Detailed explanations of my estimates are provided below.

Figure 1: Estimated Potential for New Summer and Winter Qualified Capacity from Sponsored Policy Resources in FCAs 17 and 18

Resource	New Qualified Capacity for FCA 17 or FCA 18[5]	
	Summer Qualified Capacity	Winter Qualified Capacity
Offshore Wind	800 MW to 1,300 MW	1,650 MW to 2,640 MW
Hydro Imports	Up to 1200 MW	Up to 1200 MW
Battery Storage	At least 844 MW	At least 844 MW
Solar PV	200 MW	0 MW
Total	3,044 MW to 3,544 MW	3,694 MW to 4,684 MW

[5] A resource's FCA Qualified Capacity, the quantity of capacity it may offer into the FCA, is generally the lesser of its summer or winter qualified capacity values. However, in the case of intermittent generators such as wind and solar, it is the summer qualified capacity value; for these intermittent generators, the winter qualified capacity value is awarded a capacity supply obligation in proportion to the share of summer qualified capacity that cleared in the auction.

Offshore Wind Capacity

Based on publicly available schedule information for the six large offshore wind projects that either have long-term contracts pursuant to a New England state request for proposals ("RFP") or have been selected and are currently negotiating such contracts, I estimate that up to approximately 4,700 MW (nameplate) of offshore wind may achieve commercial operation in New England by June 2027 when the Capacity Commitment Period associated with FCA 18 begins. The six projects are Revolution Wind,[6] Mayflower Wind,[7] Park City Wind,[8] Mayflower Residual,[9] and Commonwealth Wind and Vineyard Wind.[10] Vineyard Wind is the only one of these six projects that has previously qualified for the FCM. ISO-NE's published data for FCA 16 shows that the nominally 800 MW project qualified for 249.7 MW of capacity in the summer season (June to September) and 493.9 MW in the winter season (October to May).[11] This capacity qualification level is approximately 31 percent of nameplate capacity in the summer and 62 percent of nameplate capacity in the winter.[12]

As an approximation, if I assume that the other five projects will qualify at a similar portion of their nameplate rating, then these six projects altogether might qualify for roughly 1,460 MW of summer capacity and 2,914 MW of winter capacity. Vamsi

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[6] Revolution Wind Project, https://perma.cc/GYK9-LA39 (last visited Apr. 19, 2022).
[7] Mayflower Wind Project (selected under Section 83C II RFP), https://perma.cc/QR8G-5BVK (last visited Apr. 19, 2022).
[8] Park Wind Project, https://perma.cc/4WQT-GWYL (last visited Apr. 19, 2022).
[9] Mayflower Residual Project (selected under Section 83C III), https://perma.cc/BX8M-7KEF (last visited Apr. 19, 2022).
[10] Common Wealth Wind, https://perma.cc/U6WF-LZ43 (last visited Apr. 19, 2022).
[11] ISO-NE Forward Capacity Market Obligations, at Tab FCA 16, https://www.iso-ne.com/static-assets/documents/2018/02/fca_obligations.xlsx.
[12] *Supra* note 5.

Chadalavada, in his testimony, assumed a summer qualified capacity value of 27% which would result in a total summer qualified capacity for the 4,700 MW fleet of 1,269 MW.[13] As these projects have not yet qualified, their capacity value is uncertain, but likely lies in this range.

Vineyard Wind, through a combination of the FCA 13 Substitution Auction and the FCA 14 RTR Exemption has already cleared 155 MW of its summer capacity and 278 MW of its winter capacity and, therefore, this portion of that project is now treated as an existing resource for purposes of the FCM. This leaves approximately 1,300 MW of summer capacity (1,460 MW – 155 MW) and 2,640 MW of winter capacity (2,914 MW – 278 MW) as an upper bound on what might be able to qualify as new in FCA 17 or FCA 18. Alternatively, based on ISO-NE's lower estimate of 27 percent of summer qualified capacity, subtracting out the 155 MW that has already cleared, leaves about 1,110 MW as the upper bound on new offshore wind summer qualified capacity in these two auctions.

While it is possible that all six of these projects will qualify and seek to clear in FCA 17 and FCA 18, the quantity of new offshore wind capacity that might qualify in these two auctions could be less than these upper-bound figures. For example, the contracts for two of the six projects mentioned are still being finalized, and it is unclear whether their commercial operation dates ("CODs") will occur in time for FCA 18. These projects account for 1,600 MW of nameplate capacity. Without them, I would estimate the upper limit on new offshore wind capacity that could qualify for FCA 17 or FCA 18 to be about

[13] Test. of Vasmi Chadalavada on Behalf of ISO-NE Regarding the Need for a Transition to the MOPR's Elimination, at 35 (Mar. 30, 2022) ("Chadalavada Direct"), Accession No. 20220331-5296.

800 MW of summer capacity and 1,650 MW of winter capacity. Or, using ISO-NE's lower estimate, approximately 680 MW of summer capacity.

<u>Hydroelectric Capacity</u>

Massachusetts has contracted for Canadian hydro imports over a new transmission line for delivery into Western Maine with a maximum capability of 1,200 MW.[14] The success of this project is currently uncertain due to legal challenges related to siting. An alternate proposal to import up to 1,000 MW over a line into Vermont does not have a contract but the developers have said it is shovel ready. If either of these projects are successful, they may wish to qualify some or all of their 1,200 MW (or 1,000 MW) capability in the FCM. Under the proposed tariff, such import resources would be defined as Sponsored Policy Resources but would not be defined as RTRs. They would therefore be eligible to utilize the exemption from buyer side market power mitigation beginning in FCA 19 but would be ineligible for the RTR exemption in FCA 17 and FCA 18.

<u>Battery Storage Capacity</u>

According to the ISO-NE's Chief Operating Officer Report from April 7, 2022, 6,419 MW of stand-alone storage projects were in the ISO-NE interconnection queue as of March 29, 2022.[15] Only a portion of these projects are likely to reach commercial operation, and only a portion of those projects would expect to be in service in time to qualify for FCA 17 or FCA 18. To determine which storage projects might participate in these two auctions, it may be instructive to consider the battery resources that qualified

[14] New England Clean Energy Connect Project, https://perma.cc/CVA5-HQVK (last visited Apr. 19, 2022).
[15] Suppl. Notice of April 7, 2022 NEPOOL Participants Comm. Teleconference Meeting, at PDF p. 140, slide 120 (Mar. 31, 2022) ("ISO-NE Update 2022 Annual Work Plan Presentation"), https://nepool.com/wp-content/uploads/2022/04/NPC_20220407_Composite6.pdf.

for FCA 16 but did not clear, as this may be reflective of the number of battery resources that would seek to enter the market in the next year or two if they were not limited by the MOPR. In FCA 16, batteries accounted for 943 MW of new qualified capacity.[16] Of that amount, only 99 MW cleared.[17] This is not surprising given that the battery ORTP for FCA 16 was $2.601,[18] while the auction clearing price was below this value in every zone except for Southeast New England ("SENE"). Presumably at least the 844 MW of batteries that qualified for FCA 16 but did not clear would seek to participate and clear in FCA 17 or FCA 18.

Solar Capacity

In FCA 14, when a cap of approximately 336 MW remained under the prior RTR exemption, 192 MW of solar capacity cleared in the auction, though every one of these solar resources was prorated due to the RTR cap such that only 44 percent of its summer qualified capacity was able to participate in the FCA. In FCA 15, when the RTR cap was only 18 MW, only 18 MW of new solar capacity cleared. The following year, when the solar ORTP was reduced from the auction starting price to $1.381, 212 MW of solar PV cleared as New in FCA 16.[19] Though the technology has evolved quickly in recent years, this seems to suggest a pattern of about 200 MW of solar capacity seeking entry each year.

[16] ISO-NE Forward Capacity Obligations, Tab FCA 16, https://www.iso-ne.com/static-assets/documents/2018/02/fca_obligations.xlsx.
[17] *Id.*
[18] *Id.*
[19] *Id.*

Q. How will the transition mechanism likely affect the Sponsored Policy Resources expecting to achieve commercial operation in time to offer in the FCA 17 or FCA 18 auctions?

A. The MOPR will continue to prohibit Sponsored Policy Resource offers from clearing the FCA if their ORTP values are above the market clearing price, unless the Internal Market Monitor ("IMM") approves a request for a resource specific offer floor price. The ORTP values for FCA 16 and 17 are in Figure 2.

Figure 2: FCA 16 and FCA 17 ORTP Values by Generation Technology

Technology	FCA 16 ORTP ($/kW-mo)	FCA 17 ORTP ($/kW-mo)
Photovoltaic Solar	$1.381	$0.000
Energy Storage Device – Lithium Ion Battery	$2.601	$0.789
Onshore Wind	$0.000	$0.000
Offshore Wind	Auction Starting Price of $12.400 because omitted from the Tariff (ISO's calculated value was $17.948)	Auction Starting Price of $12.761 because omitted from the Tariff (had IMM's interim update methodology been used, $2.293)
Combined Cycle Gas Turbine	$9.811	$9.775
Simple Cycle Combustion Turbine	$5.355	$5.212

For example, in FCA 16 the market clearing price was between $2.531/kilowatts ("kW")-month and $2.639/kW-month.[20] The ORTP value for offshore wind was $12.400/kW-

[20] ISO-NE, *Press Release* (Mar. 9, 2022), https://www.iso-ne.com/static-assets/documents/2022/03/20220309_pr_fca16_initial_results.pdf.

month,[21] prohibiting this resource from clearing the auction.[22] Battery storage, which had an ORTP of $2.601, cleared 99 MW,[23] and the $1.381 ORTP for solar photovoltaic ("PV") permitted 212 MW to clear. No other Sponsored Policy Resources cleared the FCA 16 auction.

For FCA 17, the IMM has updated those ORTP values that are listed in the Tariff, resulting in lower ORTP values for battery storage at $0.789/kW-month and onshore wind and solar PV at $0.00.[24] However, unlike these resource types, the IMM did not update the ORTP value for offshore wind for FCA 17 because offshore wind does not currently have a technology-specific ORTP assigned to it under the Tariff and the IMM is not explicitly required under the Tariff to update ORTP values for resources that are not already included in the Tariff. As a result, offshore wind will continue to be assigned an ORTP value equal to the auction starting price in FCA 17 (and FCA 18), another Tariff requirement for resources without an ORTP value. This means that, absent utilizing the RTR exemption and risking capacity prorationing,[25] all offshore wind resources will be

[21] $12.400/kW was the FCA 16 auction starting price. Offshore wind was not assigned a technology-specific ORTP in FCA 16, but all new resources without an ORTP specified in the Tariff are given an ORTP equal to the starting price.
[22] ISO-NE, 2025–26 CCP Post Forward Capacity Auction Release of Information, at Tab IMM OFP Gen (Mar. 9, 2020) (The IMM rejected all resource-specific offer floor price requests for offshore wind resources in FCA 16.), https://www.iso-ne.com/static-assets/documents/2022/03/15-days-after-auction-posting-fca16.xlsx.
[23] Some of the battery resources that cleared in FCA 16 appear to have been co-located with solar such that the co-located resource was assigned an ORTP based on the weighted average of the solar and battery ORTPs. These resources therefor had ORTPs lower than $2.601 and would have been able to clear in more zones than just SENE despite the Battery ORTP being above the zonal clearing price.
[24] Chadalavada Direct at 8 n.4.
[25] Clean Tariff—Effective May 30, 2022, § III.13.1.1.2.10(a) (Mar. 31, 2022) (Determination of Renewable Technology Resource Qualified Capacity, "If the total FCA Qualified Capacity of Renewable Technology Resources exceeds the cap specified in [this subsection] the qualified capacity value of each resource shall be prorated by the ratio of the cap divided by the total FCA Qualified Capacity. The ISO shall notify the Project Sponsor or Market Participant, as applicable, of the Qualified Capacity value of its resource….") ("Clean Tariff—Effective May 30, 2022"), Accession No. 20220331-5296.

prohibited from clearing in FCA 17 and FCA 18 unless the auction clears at the starting price or the IMM approves a resource-specific offer floor price, both of which are unlikely given my experience with ISO-NE's process.

As I stated above, I estimate that the four offshore wind projects with approved power purchase agreements and contracted CODs that are prior to the start of the FCA 17 or FCA 18 commitment periods would be able to qualify for approximately 800 MW of summer capacity, which could be offered into the FCA. Even if these are the only resources that utilize the RTR exemption, they would use the entire RTR exemption cap in each of the two years and would be prorated such that a portion of each project's capacity would be prohibited from offering capacity into each FCA during these two years.

Using Vineyard Wind as an example, as it is discussed in more detail below, it would most likely be prorated in each of FCAs 17 and 18 such that it could only offer and clear a portion of its remaining qualified capacity in each year and would not be able to clear the final portion of the project's capacity until FCA 19, after the transition period had concluded. This project, that is under construction and scheduled to reach COD in Q2 2024, would have to wait until the auction associated with the commitment period starting June 2028 to offer and clear its entire qualified capacity into the market. Should the two offshore wind projects currently negotiating their power purchase agreements have schedules that enable them to qualify for FCA 17 or FCA 18, the proration levels during the transition period would rise such that another roughly 500 MW of capacity would be excluded from the market.

In addition, if the ORTP values for onshore wind, solar, or batteries increase for FCA 18, they could preclude these resources from clearing in FCA 18 as well unless they overcome the same hurdles as offshore wind. Further, should any Canadian hydro imports over new transmission lines be ready to seek qualification in FCA 17 or FCA 18, the RTR exemption will not be an option to them, as the exemption is limited to generating capacity resources and therefore excludes imports. Such a resource, unless it is able to receive approval for a low resource-specific offer floor price, would be excluded from the market until FCA 19.

Q. Why is offshore wind the only technology type whose ORTP value was fully calculated by ISO-NE for FCA 16 but has not been updated for FCA 17?

A. As discussed above, the IMM calculated an ORTP for FCA 16 for all resource types that passed an initial screen, including onshore wind, offshore wind, solar PV, and battery storage. The IMM used the resource's capital costs, operating costs, and expenses such as depreciation and taxes to calculate the break-even contribution that it will require from the FCM, which becomes the ORTP value.[26] For offshore wind, ISO calculated an ORTP of $17.948/kW-month for FCA 16.[27] As this was above the FCA 16 starting price of $12.400/kW-month, this value was not included in the Tariff's table of ORTPs in III.A.21.1.1 of the Tariff. The ORTP values calculated for onshore wind, solar PV, and battery storage were below the auction starting price, and were thus included in the Tariff.

[26] Appendix B Removal Joint Filing Letter, Clean Tariff at App. A §§ III.A.21.3(a), (b), Docket No. ER21-2220 (June 28, 2021) ("Section III, Market Rule 1"), Accession No. 20210628-5033.
[27] ORTP Cover Letter and TOC, at 30, Docket No. ER21-1637 (Apr. 7, 2021) (ISO-NE Transmittal Letter), Accession No. 20210407-5305.

In the years that the IMM does not perform a full recalculation of ORTPs, the Tariff dictates that the ORTP values are to be updated using specified indexes to adjust the model assumptions for capital cost, energy and ancillary service revenue, and renewable energy credit ("REC") revenue.[28] The bonus depreciation and investment tax credit values are also adjusted as specified in the Tariff.[29] The IMM has interpreted this to mean that only resources which have a technology-specific ORTP documented in the Tariff will be updated in interim years. As a result, resources like offshore wind, for which a full ORTP calculation was performed prior to FCA 16 but for which the resulting ORTP value was not specifically documented in the Tariff, do not have their ORTP values updated in interim years. Thus, because the FCA 16 ORTP value for offshore wind was set generically at the auction starting price for FCA 16, the IMM will not adjust it in the interim years of FCA 17 and FCA 18.

Q. Would updating the ORTP value for offshore wind allow these resources to clear in FCA 17, despite the proposed transition mechanism's restrictions?

A. Yes, using the spreadsheet that the IMM published showing their calculations to adjust the FCA 16 ORTP values for FCA 17,[30] it appears that if these same adjustments were made to the offshore wind ORTP calculation that it would have allowed offshore wind

[28] Section III, Market Rule 1 § III.A.21.1.2(e).
[29] *Id.*
[30] ISO-NE IMM, ISO-NE Summary of 2026-2027 ORTP Values, https://www.iso-ne.com/static-assets/documents/2022/03/2026-2027-ccp-forward-capacity-auction-17-iso-offer-review-trigger-price.xlsm (last updated Apr. 13, 2022). Please note that my calculations are based on the prior version of this spreadsheet that ISO-NE published on March 25, 2022, using the same link. In the March 25 version all of the necessary formulas for calculating the offshore wind ORTP were included. In the revised version posted on April 13, these formulas had been removed and the dollar year of the REC value has been changed. However, the updated values do not materially alter the calculations used in my testimony.

the opportunity to clear in FCA 17.[31] A summary of the relevant data from that spreadsheet is in Figure 3 below.

If I adjust the FCA 16 offshore wind assumptions (which were included in the IMM's spreadsheet) in the way specified for the interim year updates, just as the IMM did for the other technology types, according to my calculation the FCA 17 ORTP value for offshore wind would decrease to $2.293/kW-month, which is below the FCA 17 Auction Starting Price of $12.761/kW-month, and also below the FCA 16 clearing price in every zone. In other words, had this interim year update process been applied for the FCA 17 offshore wind ORTP value, this resource type would very likely have been able to participate and clear in FCA 17 regardless of the ISO's proposed extension of the MOPR for two more years.

Figure 3: FCA 17 ORTP Annual Update Values for Offshore Wind Resources

2027$		NPV		$/kW-yr		$/kW-mo
Expenses						
Fixed	$	1,181,447,407	$	111.35	$	9.279
Tax	$	(1,422,634,231)	$	(134.08)	$	(11.173)
Install Costs	$	4,641,811,711	$	437.47	$	36.456
Gross CONE	**$**	**4,400,624,887**	**$**	**414.74**	**$**	**34.562**
Revenues						
PFP	$	40,176,501	$	3.79	$	0.316
Scarcity	$	20,408,565	$	1.92	$	0.160
E&AS	$	2,435,317,709	$	229.52	$	19.127
REC	$	1,769,091,730	$	166.73	$	13.894
Revenue Offset	**$**	**4,264,994,506**	**$**	**401.96**	**$**	**33.497**
Net CONE Installed	**$**	**135,630,382**	**$**	**12.78**	**$**	**1.065**
Net CONE Qualified	**$**	**291,942,715**	**$**	**27.51**	**$**	**2.293**

[31] To be clear, it would have given them an opportunity to clear but would not have guaranteed them the ability to clear, as the FCA 17 clearing price could be higher or lower than the FCA 16 clearing price.

Q. Should the Commission require ISO-NE to adjust the ORTP values for all the technology types that went through the full recalculation process in the interim years?

A. I think this is further evidence of why the MOPR should simply be eliminated for FCA 17, which would avoid the need to update ORTP values for FCA 17 and FCA 18. The MOPR mitigation rules appear increasingly arbitrary.

That said, if the MOPR continues to exist, then yes, ISO-NE should be required to adjust the ORTP for all technology types that were fully recalculated in FCA 16. The Tariff language is sufficiently broad to allow for this interpretation.[32]

The IMM will not be overburdened with adjusting the ORTP values for numerous resources whose FCA 16 ORTP fell above the Auction Starting Price since, as Figure 2 demonstrates, offshore wind is the only technology type that is in this situation. Furthermore, like the other technology types that were updated for FCA 17, because the full recalculation was done for FCA16 there would be no need to bring in a consultant or perform additional review as there is already a Tariff-prescribed method for updating the ORTP values in these interim years.

Finally, because of the interim year update that the IMM has already performed on the other technology types, they already have in their spreadsheet all but one piece of data necessary to perform the annual update for offshore wind. They would simply need to add the offshore wind values to their table of Bloomberg Levelized Cost of Energy

[32] Section III, Market Rule 1 § III.A.21.1.2(e) reads: "For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows."

("LCOE") index values and then all the necessary information to make the update would be contained in their spreadsheet and it would simply be a matter of updating the offshore wind formulas in the same way that they have already done for the other technology types.

IV. RELIABILITY CONCERNS

Q. Please summarize the reliability issues that ISO-NE seeks to mitigate with the proposed transition mechanism.

A. ISO-NE raises two primary reliability issues, which I summarize below.

A. Failure to replace "inefficient retirements" on a timely basis

ISO-NE argues that the transition mechanism is necessary to prevent shortfalls in the FCM resource adequacy requirements. ISO-NE believes that permitting an unlimited number of new Sponsored Policy Resources to clear in the market as early as FCA 17 will spark a wave of retirements of existing fossil-fuel generators ("inefficient retirements"), which ISO-NE characterizes as providing beneficial dispatchable and controllable features. The ISO-NE explains that once a retirement bid is accepted, it is powerless to delay the resource's retirement date unless the delay is for specified local transmission security issues. While new resources could replace retiring or delisted existing resources, ISO-NE argues against relying on such replacements when they come in the form of Sponsored Policy Resources that would be unable to clear absent some kind of exemption to the MOPR because they, like most new projects, are prone to delays, which would cause a resource adequacy gap.

Specifically, ISO-NE explains that its FCM has a small margin of error. In FCA 16, ISO-NE's capacity surplus was 1,165 MW.[33] ISO-NE compares this amount with the six offshore wind projects that have so far been selected for long-term contracts by the New England states with a total nameplate capability of 4,700 MW. Of this amount, ISO-NE estimates that 27 percent or 1,269 MW would be the projects' FCA qualified capacity. ISO-NE suggests that all six of these projects might clear in a single FCA and then be delayed by a year because no wind turbine installation vessels are currently available to support construction of the projects.[34] Thus, if all six of these projects were to clear in FCA 17 but not be constructed in time for the start of the associated Capacity Commitment Period, ISO-NE's FCM could experience a capacity deficit, or negative planning margin, of 104 MW (1,165 MW minus 1,269 MW). In the ISO's words, this would pose a "serious resource adequacy concern to the region for that commitment period."[35]

B. <u>Failure to accurately assess the resource adequacy values of new and existing resources</u>

In addition, ISO-NE believes that the changing resource mix will eventually require it to use an accreditation methodology that will more precisely assess the resource adequacy contributions of new and existing resources. Even if an existing resource is replaced in a timely manner such that the above-described concern does not come to pass, ISO-NE

[33] Chadalavada Direct at 33–34.
[34] This is inaccurate. There are no Jones Act-qualified offshore wind turbine installation vessels currently available, but there are construction methods that legally allow a foreign-flagged installation vessel to be used for construction of an offshore wind project in the United States. This was the method used for the two operating offshore wind projects in the United States.
[35] MOPR Elimination Filing Letter, at 38 (Mar. 31, 2022) (citing Chadalavada Direct at 37) ("Transmittal Letter"), Accession No. 20220331-5296.

argues that a new Sponsored Policy Resource might not have the same reliability value as the retiring resource it displaces, even if they are both nominally qualified for the same quantity of capacity in the FCM.

As an example, ISO-NE compares the capacity values of solar and fossil-fuel resources. The fossil-fuel resource in ISO's example has a nameplate and summer qualified capacity of 400 MW, while the solar resource has an 800 MW nameplate and a 400 MW qualified capacity value.[36] After the sun goes down and during cold, dark winter hours, ISO-NE points out that unlike the displaced fossil resource, the "actual contributions to reliability of the PV solar resource may be a fraction of the 400 MW for which it would be paid."[37] ISO-NE therefore concludes that 1 MW of qualified capacity from a solar resource does not provide the same reliability benefit as 1 MW of qualified capacity from a fossil-fuel generator.[38]

Thus, to prevent the possibility of a resource adequacy supply gap, ISO-NE argues that it must use the MOPR as a means to limit the entry of new Sponsored Policy Resources into the market for two years while it develops revised procedures for determining qualified capacity values.

[36] *Id.* at 37.
[37] *Id.* (citing Chadalavada Direct at 14).
[38] *Id.* at 37.

Q. Are these reliability concerns a reasonable basis for extending the MOPR for two more years?

A. No, they are not. I will address each of the two reliability concerns in turn.

C. <u>Failure to replace "inefficient retirements" on a timely basis</u>

ISO-NE's contentions 1) misstate the probability that certain offshore wind projects will achieve commercial operation timely and 2) ignore the various tariff provisions that provide the very protections that ISO-NE seeks to provide by restricting Sponsored Policy Resources from participating in the FCM.

1. *Commercial Operation of Offshore Wind Projects*

First, regarding ISO-NE's concern related to New offshore wind resources being delayed and thus creating a temporary capacity deficit, there are several flaws in ISO-NE's argument. ISO-NE prematurely assumes that all six of the offshore wind projects that make up the 1,269 MW of potential New qualified capacity in this timeframe will seek to offer that capacity and be qualified by the ISO-NE to offer that capacity, in FCA 17 and FCA 18. Two projects making up 1,600 MW (nameplate, which using ISO-NE's assumptions would translate into 432 MW qualified capacity) of this total are still negotiating contracts and do not yet have firm targets for their CODs. While it is possible, it is uncertain at this time whether these projects' target CODs will be prior to June 1, 2027, which would be a pre-requisite to qualify for FCA 18.

Further, ISO-NE's assumption predicating their claim of a reliability risk—that <u>all six</u> offshore wind projects could clear in an FCA but then delay their COD by a full year—is improbable. The most advanced of these six projects is the Vineyard Wind project, which commenced construction in November 2021.[39] Vineyard Wind submitted an updated project schedule to the Bureau of Ocean Energy Management ("BOEM") in January 2022 showing that wind turbine installation and commissioning would occur over the period from Q2 2023 through Q2 2024, while all other construction activities would be completed by Q4 2023.[40] It is unclear from this schedule whether the project will begin partial operations at the end of 2023, adding the output of each subsequent group of turbines as they are commissioned, or whether it will wait to begin operating until all turbines are commissioned. In other words, the project could begin partial deliveries at the end of 2023 and make full deliveries starting in Q2 2024 according to its latest schedule.

The next most advanced of these six projects is Revolution Wind. Its Construction and Operations Plan submitted to BOEM in April 2021 shows a project schedule in which construction begins in 2023.[41] Shipbuilding of the turbine installation vessel for this project has already reached the halfway mark and is on schedule to be completed by December 2023. Once complete, the ship's first contracted task is the installation of turbines at Revolution Wind and Sunrise Wind, both joint projects of Ørsted and Eversource that are expected to be completed by 2025.[42]

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[39] Iberdrola, *Vineyard Wind 1 Offshore Wind Farm*, https://perma.cc/J8T7-X9UT (last visited Apr. 19, 2022).
[40] U.S. Dep't of the Interior, BOEM, *Vineyard Wind I*, https://perma.cc/5RAV-MWCV (captured by going to https://www.boem.gov/vineyard-wind, selecting Construction and Operation Plan option, clicking Updated Construction Schedule (Jan. 2022)).
[41] Revolution Wind (submitted to BOEM), *Construction and Operations Plan, Revolution Wind Farm Volume I*, at 60 (§ 3.2 Project Schedule) (Apr. 29, 2021), https://perma.cc/6AKS-LU5Y.
[42] Sunrise Wind (Powered by Ørsted & Eversource), *About Sunrise Wind*, https://perma.cc/TH9Z-36F9 (last visited Apr. 19, 2022); Revolution Wind (Powered by Ørsted & Eversource), *About Revolution Wind*, https://perma.cc/BJS8-S647 (last visited Apr. 19, 2022).

The FCA 17 commitment period begins in June 2026, a full two years after the Vineyard Wind construction schedule shows the project will be complete and a year after the Revolution Wind project is expected to be complete. Though delays to the construction schedule may still occur, it seems unlikely that there will not be a single large offshore wind project operating in New England before June 2026 based on the significant progress already made by these two projects to date.

2. *Tariff Provisions that Protect the FCA Process*

Second, with respect to ISO-NE's existing Tariff provisions, ISO-NE has a rigorous qualification process for new resources seeking to enter the market. This includes submittal of a Critical Path Schedule ("CPS") by the Project Sponsor showing that the resource will achieve commercial operation prior to the start of the relevant Capacity Commitment Period. ISO-NE must review the CPS, typically with the assistance of an expert consultant, and make a determination as to "whether the milestones in the critical path schedule are reasonable and likely to be met."[43] ISO-NE must make a positive determination before the project can submit an offer into an auction. ISO-NE is not a passive bystander that must simply watch and accept as proposed resources prematurely take on Capacity Supply Obligations for which they are unlikely to be able to deliver. I recommend that ISO-NE rely on these tariff provisions to mitigate its concerns regarding project delays, rather than use the transition mechanism to preemptively exclude Sponsored Policy Resources from participating in the FCM.

[43] Clean Tariff—Effective May 30, 2022 § III.13.1.1.2.4.(c) (Evaluation of New Capacity Qualification Package) (emphasis added).

D. <u>Failure to properly assess the resource adequacy values of new and existing resources</u>

ISO-NE argues that a new Sponsored Policy Resource might not have the same reliability value as the retiring resource it displaces, even if they are both nominally qualified for the same quantity of capacity in the FCM. Yet it does not provide any evidence that the specific resource types that would most likely be prevented market entry due to the two-year extension of the MOPR—particularly, offshore wind and imports—have lower reliability value than the existing resources they would likely replace. I believe that the opposite is more likely to be true and explain why here.

However, first I will respond to ISO-NE's flawed contention that solar resources, unlike thermal fossil units, may only deliver a fraction of the capacity for which they would be paid.

ISO-NE's current accreditation methodology accounts for the capacity that solar resources can provide during critical resource adequacy hours throughout each season. A solar resource with 800 MW nameplate capacity, which may regularly deliver 800 MW of energy during gross peak load conditions, will receive credit and payment for just half this, its summer qualified capacity value of 400 MW, in the 4 summer months precisely because the current accreditation system recognizes that the resource does not provide 800 MW of capacity in all hours of the day. During the remaining 8 months of the year solar resources do not receive any credit or payment for capacity because the current accreditation system recognizes that solar cannot dependably perform during the after-dark hours, which is particularly critical during the winter months.

Turning back to ISO-NE's example, on an annual basis the 800 MW solar resource is only paid one third of the amount that the 400 MW fossil-fueled resource is paid because the solar accreditation methodology takes into account the actual performance of the solar resource at times of the current system's highest stress. The 400 MW fossil-fuel resource, on the other hand, is paid for its full capacity regardless of how often or when it is unavailable due to maintenance or forced outages, fuel unavailability, lengthy start-up times, or prohibitively expensive fuel costs.

Though ISO-NE provides an example of a solar PV resource replacing a fossil-fueled resource, ISO-NE also points out that solar PV has an ORTP of $0.00 in FCA 17.[44] Thus, MOPR extension or not, solar PV will have unmitigated entry in FCA 17. While solar PV's ORTP value for FCA 18 is not yet known, even were the ISO's concern related to solar replacement of fossil generation to be well founded—the MOPR extension will *do nothing* to address it for at least one of its two years. Instead, as ISO-NE identified, the resource types most likely to be subject to exclusion from the market due to the MOPR extension are offshore wind and imports over a new transmission line.[45] Yet ISO-NE's own studies show that these resources provide some of the best reliability value to the system during the cold winter conditions in which the region appears to face its greatest reliability concerns.

For example, ISO-NE presented their Operational Fuel Security Analysis ("OFSA") to the NEPOOL Reliability Committee on January 24, 2018.[46] In the OFSA ISO-NE

[44] Chadalavada Direct at 8 n.4.
[45] Transmittal at 31; Chadalavada Direct at 10.
[46] ISO-NE, *Operational Fuel-Security Analysis* (Jan. 17, 2018), https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.

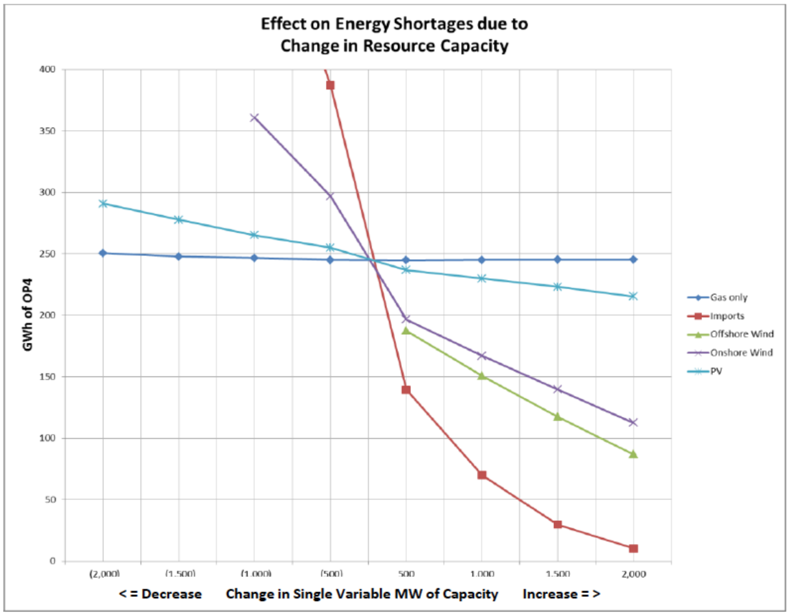
constructed twenty-three possible future scenarios and focused on a 90-day period from December through February in the winter of 2024/2025. For each of these scenarios it sought to quantify the extent to which the region would fall short of the energy needed to meet demand (i.e., load shedding) or require emergency actions related to the risk of an energy shortfall (i.e., OP-4 Actions). A total of nineteen scenarios resulted in load shedding, including the one that ISO-NE labelled the "reference scenario" that included no new offshore wind and no new imports. Among the four scenarios that did not result in any load shedding, the common factor was an increase in the amount of supply that was not dependent on gas pipelines—i.e., either new renewables, new imports, more LNG, or some combination of these. In fact, the case that included a modest 1,370 MW (nameplate) of new offshore wind and 1,000 MW of new imports was one of the best-performing cases.[47]

On April 27, 2018, ISO-NE posted a second OFSA presentation that contained an analysis of additional scenarios requested by stakeholders as well as a sensitivity analysis of the impact of changing individual variables in the analysis. The following figure shows the change in the GWh of emergency OP-4 actions if the number of MWs (nameplate) of different resource types were either increased or decreased from the reference case. The outcome is most sensitive to changes in the amount of imports (red), with offshore wind (green) and onshore wind (purple) as the next most impactful resources. PV (light blue) has a small impact while gas (dark blue) has almost no impact whether it is increased or

[47] ISO-NE, *Operational Fuel-Security Analysis (Discussion with Stakeholders)*, at Slide 32 and App. A, slide A16, Scenario "More Renewables" (Jan. 24, 2018) (30 MW of existing and 1,370 MW of new offshore wind used in this scenario while only 30 MW of existing offshore wind included in the reference scenario) ("ISO-NE OFSA Presentation"), https://perma.cc/H46W-UD6W.

decreased by as much as 2,000 MW. Thus, according to the ISO's own analysis, additions of imports and wind to the grid appear to be some of the most beneficial actions the region could take to improve winter reliability.

Figure 4: Effect on Energy Shortages Due to Changes in Resource Capacity



Change in Capacity (MW)	Gas only (GWh of OP4)	Imports (GWh of OP4)	Offshore Wind (GWh of OP4)	Onshore Wind (GWh of OP4)	P (GWh o
-2,000	251	1,072	-	-	29
-1,500	248	787	-	-	27
-1,000	247	567	-	361	26
-500	245	387	-	297	25
500	245	140	188	197	23
1,000	245	70	151	167	23
1,500	245	30	117	140	22
2,000	245	11	87	113	21

E. **The Current Accreditation Approach for Wind Remains Reasonable Through the Transition Period**

In December 2010, ISO published the New England Wind Integration Study ("NEWIS"), looking at the system as forecasted in 2020 with a variety of scenarios for onshore and offshore wind build out. One of the key questions that study sought to answer was whether the ISO's heuristic approach to determining qualified capacity value for onshore and offshore wind was a reasonable approximation to the effective load-carrying capability ("ELCC") value of these resource types.

The analysis in NEWIS found that at low levels of wind installations in the region, the ISO-NE's heuristic approach under-valued the capacity contribution of these resources. However, as penetration rates for wind increased, NEWIS found that the capacity contribution from these resources diminished until it was ultimately less than the current heuristic approach. The crossover point found in NEWIS was when wind resources provided approximately ten percent of the region's energy, which in the various study cases was between 4,400 MW and 5,200 MW of wind (nameplate), depending upon the specific mix of wind projects included.[48] This is depicted in the Figure 5 below from the NEWIS report, in which "On-Peak CF" reflects the ISO's current capacity accreditation approach and "ELCC" reflects an ELCC accreditation approach.[49]

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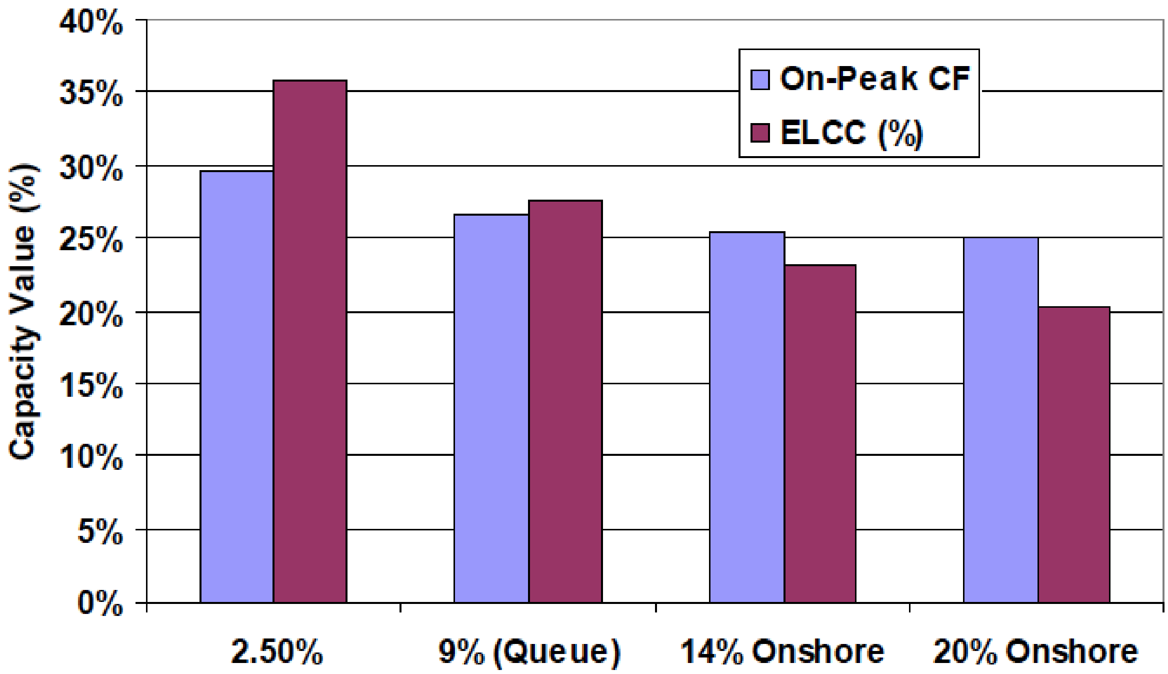
[48] GE Energy, *Final Report: NEWIS*, at 326 (Dec. 5, 2010) (Looking at the average results over three years, at the 2.5% energy penetration the approximate calculation underestimates the capacity value by about five percentage points, roughly 30% versus 35%. At the 20% penetration the effect is reversed. Now the approximate method appears to overestimate the capacity value by five percentage points, 25% versus 20%. The crossover appears to occur at roughly the 10% penetration level."), https://perma.cc/2MEM-TGWZ.

[49] While the authors of this study thought they were modeling ISO's current capacity accreditation approach (what they have labelled "On-Peak CF" in the figure), they actually made one seemingly small but ultimately significant error which led to them over-estimating wind's qualified capacity values under ISO's current methodology. The error is that they assumed ISO's approach used the generators' average production level during the seasonal reliability hours, whereas the ISO's approach actually uses the median. *See* Clean Tariff—Effective May 30, 2022 §§ III.13.1.2.2.2– III.13.1.2.2.2.2. ISO gave a presentation to the Variable Resource Working Group in December 2015 demonstrating that in the case of New England wind resources the median value is substantially lower than the average. *See* ISO-NE, *Intermittent Resource Review: Use of Median Output to Determine Qualified Capacity Values*, at slide 9 (Dec. 7, 2015), https://perma.cc/9HV9-9E3Q. For the wind resources evaluated by ISO at that time, the mean summer value was 43% higher than the median and the mean winter value was 9% higher than the median. Had this error been corrected in the NEWIS report, it would have shown that the current accreditation process further under-values wind presently, the cross-over point would be later, and then the amount by which the current approach over-valued wind's capacity at 20% wind penetration would be lower than shown. This means that the crossover point is likely to be later than 10% wind penetration, which in turn means there's more headroom before any of this becomes the potential problem that ISO-NE is trying to claim already exists when it comes to offshore wind.

Figure 5: Comparison of Capacity Values



The ISO-NE wind fleet consists of nearly 1,500 MW (nameplate) today, meaning that the crossover point at which 1 MW of wind qualified capacity using today's qualification methodology is worth less than 1 MW of capacity using the ELCC approach, would be expected to occur once an additional 2,900 to 3,700 MW (nameplate) of wind is added to the system. With 4,700 MW of offshore wind having been selected for contracts by the New England states, it seems entirely appropriate that now is the time to begin evaluating new approaches to capacity accreditation that can be used in the coming years. However, the NEWIS report should give some comfort in that it finds that even though the capacity value of wind varied across the study cases, it gives an "overall reasonable" approximation even up to the twenty percent wind penetration level studied.[31] This would correspond to about 8 to 10 GW of wind installations, which far exceeds the level that could enter the market in the FCA 17 and FCA 18 timeframe. The NEWIS report findings would therefore suggest that there is still time before a new accreditation approach for wind would be necessary to implement.

F. ISO-NE's history of mischaracterizing the source of reliability risks

In its comments filed with the Commission on March 9, 2018, focused on the OFSA findings, ISO-NE repeatedly characterized renewables as exacerbating the system's fuel security problems (just as they have characterized renewables as exacerbating resource adequacy risks in this filing) despite the OFSA results not showing this. The January 23, 2018 presentation of the OFSA results stated that a resource mix with "[h]igher levels of LNG, imports, and renewables can minimize system stress and maintain reliability."[50] Yet in its March 9, 2018 comments ISO-NE stated "[t]he increasing shift away from generators with on-site fuel to natural gas-fired generators relying on "just-in-time" fuel-delivery infrastructure (or to generators using inherently variable fuel, in the case of wind and solar) has further exposed the limitations of New England's existing fuel-delivery system and heightened the region's fuel-security risk, particularly during the winter."[51] When one looks at ISO-NE's study findings, they show that increased offshore wind and imports are beneficial to system reliability, but this would not be gleaned from reading ISO-NE's comments.

Q. What is the basis for ISO-NE's assertion that the transition mechanism is needed?

A. ISO-NE's basis for the transition mechanism is unclear. Despite evidence to the contrary, ISO-NE relies on the notion that the FCM must keep as many existing fossil generators as possible to avoid resource adequacy shortages, even while it reports that

[50] ISO-NE OFSA Presentation at Slide 13, bullet 6.
[51] Response of ISO-NE, at 6, Docket AD18-7-000, Accession No. 20180309-5121.

about 3,700 MW of the capacity held by gas-only resources is not expected to be available during cold winter conditions.[52] ISO-NE admits that its system has faced numerous supply challenges but has yet to describe an incident involving a Sponsored Policy Resource.[53]

Similarly, ISO-NE argues that allowing any amount of Sponsored Policy Resources beyond the RTR exemption to bid in FCA 17 and FCA 18 will cause the market clearing prices to decline and, consequently, spur inefficient retirements of existing fossil-fuel resources.[54] However, on the other hand, it also argues that the same scenario could spur retirements and/or delists that could increase clearing prices "in certain or all capacity zones."[55]

Thus, I cannot determine a coherent basis for ISO-NE's claim that the transition mechanism is needed, particularly since excluding Sponsored Policy Resources of the type most likely to be excluded by the transition mechanism is antithetical to improving ISO-NE's resource adequacy.

Q. Did ISO-NE perform an analysis to support its reliability concerns?

A. No, it has not, which explains its counterintuitive approach to meeting resource adequacy requirements (i.e., restricting supply of reliable Sponsored Policy Resources).

[52] ISO-NE, *NEPOOL Participants Committee Report*, at Slide 18 (PDF p. 178) (Oct. 7, 2021), https://perma.cc/7YSL-LHS4.
[53] Chadalavada Direct at 37.
[54] Transmittal Letter at 36.
[55] *Id.* at 44 n.163.

ISO-NE admits that its "inefficient retirement" theory has not been studied.[56] In fact, ISO-NE has not performed an analysis of its system capabilities to quantify the reliability benefits, if any, of the proposed two-FCA cycle delay of MOPR reforms. Also, ISO-NE has not demonstrated that its Markets Committee Proposal to exempt state-sponsored resources from buyer-side mitigation rules cannot be achieved reliably starting in FCA 17.[57] In contrast, ISO-NE has previously acknowledged that exempting state-sponsored resources from its buyer-side mitigation rules is feasible.[58]

As a substitution for its own analysis, ISO-NE points to the root cause analysis of the extreme weather events in California during the summer of 2020 to suggest that the transition mechanism is necessary to avoid similar consequences in ISO-NE. ISO-NE points to supply shortfall during net peak load hours, imprecise Net Qualified Capacity values for wind and solar resources, and the retirement of Once-Through Cooling generators as issues that the transition mechanism could potentially help it avoid. ISO-NE simply states that "many of the same conditions that led to California's August 2020 outages have the potential to arise in New England,"[59] but provides no basis of comparison between the New England and California systems to demonstrate how similar they are nor the potential timing of these conditions arising here (i.e., might they

[56] Chadalavada Direct at 17–18.
[57] December 2021 Markets Committee Meeting ("Markets Committee Proposal"), https://www.iso-ne.com/static-assets/documents/2022/01/a02a_mc_2022_01_11-12_mopr_removal_iso_tariff_redlines_rev1.docx.
[58] ISO-NE, Executive Vice President and Chief Operating Officer Memorandum to NEPOOL Stakeholders, at 5 (PDF p. 200) (Jan. 26, 2022), https://perma.cc/H9ZS-JLAG.
[59] Chadalavada Direct at 21:1–2.

arise during the transition period or rather is this something that has the potential to occur on a longer-term basis?).

ISO-NE also references its 2050 Transmission Study which is currently underway. In this study, ISO-NE utilized one of the eight scenarios developed as part of a Massachusetts study of deep decarbonization pathways for the year 2050 as the basis for its modeling assumptions. The 2050 Transmission Study looked at system operating conditions under 12 "snapshots" of varying system conditions and found that in all of them "the dispatch of fossil-fueled generation would be necessary to achieve a load-generation balance."[60] ISO did not, however, quantify how much fossil-fueled generation would be necessary to achieve this balance. Based in part on this finding, ISO-NE believes that delaying the MOPR elimination for Sponsored Policy Resources is warranted "so as to avoid the inefficient loss of resources that may well be necessary to reliably operate the system well into the future, as part of the transforming resource mix."[61]

Q. Will the transition mechanism favor certain resource types over others?

A. Yes. ISO-NE's explanation for needing the transition mechanism is based on its preference for retaining the existing fossil-fuel resources.[62] While ISO-NE's tariff provides provisions to address circumstances that might compromise its ability to secure

[60] Chadalavada Direct at 17:8–9.
[61] *Id.* at 17:9–11.
[62] *Id.* (justifying the two-year delay by stating that "the dispatch of fossil-fueled generation" in the FCM is necessary now and in the future); *id.* at 14:8–9 (stating that "existing thermal resources provide additional benefits to the system given their dispatchable and controllable nature."); Transmittal Letter at 36–37 (comparting solar resources to fossil-fuel generators while only highlighting the limitations of solar technology); *id.* at 37 (using example stating that fossil-generation can provide its nameplate capacity without recognizing deficiencies such as outages and fuel supply shortages); *id.* at 36 (stating existing resources that have "important reliability benefits for the region" verses intermittent resources, which "currently have only limited or no storage capabilities.").

sufficient capacity, it seeks to only apply those provisions when existing fossil-fuel generators are involved. For example, ISO-NE claims that it cannot rely on new resources to replace existing resources (despite this being one of the underlying tenets of the FCM) because new resources might not achieve commercial operation on time. However, ISO-NE ignores that its tariff has a rigorous qualification process to assess the viability of projects and the probability that they will be able to deliver timely.[63] Further, should there be delays among new resources that clear in an FCA, the market rules have mechanisms to replace that capacity through the reconfiguration auctions as has been done many times before (to the extent alternative uncommitted capacity is available).

Further, ISO-NE places unreasonable expectations on Sponsored Policy Resources, particularly since it admits that “state-sponsored resources are more likely than other resources to achieve commercial operation.”[64] In its example using the 104 MW supply shortfall that would occur if its anticipated state-sponsored projects are delayed, ISO-NE assumes that all six projects will not achieve commercial operation on time. As I described above, ISO-NE's assumption is implausible. The transition mechanism will exclude capable and reliable resources from meeting the region’s resource adequacy requirements in the FCM.

[63] *See* Clean Tariff—Effective May 30, 2022 § III.13.1.1.2.4. (Evaluation of New Capacity Qualification Package).
[64] Chadalavada Direct at 47:8–9.

Q. Do you agree with ISO-NE's contention that it lacks the tools to quantify whether the transition mechanism is needed to mitigate reliability concerns?

A. No. ISO-NE has performed sufficiently indicative studies, such as the OFSA and NEWIS studies that I discussed above, and none has concluded that the Sponsored Policy Resources most likely to be excluded from the market during this delay period would heighten reliability risks if allowed to enter. Thus, ISO-NE not only has the tools to quantify the impact of and need for the transition mechanism but also has already used them to perform studies that have demonstrated the particular Sponsored Policy Resources in question will provide substantial resource adequacy and system reliability benefits to its system.

Q. Will the transition mechanism lessen or, instead, heighten the reliability risk that ISO-NE has identified in its service territory?

A. The transition mechanism will likely heighten the very reliability risks that ISO-NE claims it is designed to mitigate for two reasons, which I will walk through here.

G. <u>Incentive for Sponsored Policy Resources to Offer Capacity in FCA 17</u>

First, were the ISO's Markets Committee Proposal without a delay to be implemented, Sponsored Policy Resources would not feel any MOPR-related pressure to attempt to enter the market prematurely, as they would be guaranteed exemption from buyer side market power mitigation beginning in FCA 17 and for all subsequent auctions. Even a project that may potentially be able to reach commercial operation prior to June 1, 2026 (the start of the capacity commitment period associated with FCA 17) but more realistically expects to be commercial by June 1, 2027 (the start of the Capacity

Commitment Period associated with FCA 18) would have no MOPR-related reason to rush into participation in FCA 17 as it would be confident in its ability to enter the market unmitigated when it was ready in FCA 18.

Conversely, under the ISO's actual proposal that includes a two-year delay in which the MOPR still applies with just a limited RTR exemption, there is a significant incentive for certain Sponsored Policy Resources in the above situation to enter the market in FCA 17 even if that is premature. The reason for this is that the FCA 17 ORTP values for onshore wind, solar PV, and battery energy storage are $0.00, $0.00, and $0.789/kW-month, respectively. Onshore wind and solar are guaranteed to be able to clear their offers in FCA 17 regardless of the MOPR extension, as the clearing price cannot fall below their $0.00/kW-month ORTP. While technically it is possible that the MOPR could limit battery energy storage projects from clearing in FCA 17, in practice this appears implausible given that the lowest price at which any FCA has cleared to date is $2.001/kW-month, more than two and a half times the battery ORTP value. In short, these Sponsored Policy Resources can be confident that their offers will not be mitigated in FCA 17.

The same cannot be said for FCA 18. In spring 2023, the IMM will perform the annual adjustment to its ORTP values for FCA 18 as specified in Section III.A.21.1.2(e) of the Tariff, just as it did at the end of March 2022 for FCA 17. This will include adjustments to the capital cost assumptions, REC revenue assumptions, energy and ancillary service revenue assumptions, investment tax credit ("ITC") assumptions, and the bonus tax depreciation assumption. If Bloomberg's LCOEs, used to adjust the capital cost assumption for these particular technologies, continue to rise this year, as Bloomberg reported it did from the first half of 2021 through the second half of 2021 (the FCA 17 values are based on data through the first half of 2021),[65] or if fuel prices come back down in a year such that the energy and ancillary service revenue assumption is lower, either of those could lead to higher ORTP values for batteries in FCA 18. Solar and onshore wind also could potentially have higher ORTP values in FCA 18 based on those two adjustments as well as if REC prices were to recede in the next year, and due to the prescribed ITC stepdown for solar.

No market participant can know prior to FCA 17 what the outcome of that ORTP update for FCA 18 will be. But any developer of these resources would be aware of the risk that if they do not clear in FCA 17, they may be limited by their ORTP in FCA 18. [66] With the possibility that the RTR cap would be exceeded in FCA 18, this developer would then be faced with the decision of clearing in FCA 17, knowing that the market rules do not penalize a resource for being delayed by up to two years,[67] or waiting for FCA 18 and risking that their capacity offer would be prorated that year. The calculus indicates that

[65] Will Wade, *Power Plants Get More Expensive But Renewables Still Cheapest*, Bloomberg (Dec. 21, 2021), https://perma.cc/B6B7-D5UY.
[66] Such a developer, if it submitted its Interconnection Request between June 1, 2020 and May 31, 2021 would also be aware that the Capacity Network Resource ("CNR") portion of their Interconnection Service request would expire following FCA 18 such that they would need to submit a new CNR-Only Interconnection Request and receive a queue position at the end of the queue for use in the FCA 19 qualification process. Though the MOPR would not prevent the resource from clearing in FCA 19, the risk of losing the project's queue priority for purposes of the overlapping impact test in the FCA 19 qualification process would be a strong incentive for the resource to attempt to clear before its initial CNR request expired. Without any certainty as to whether it would be able to clear in FCA 18 due to the unknown ORTPs for that year, this would be a further reason that such a developer would be interested in clearing in FCA 17.
[67] Any additional financial assurance requirements during this delay would be returned to the project sponsor upon FCM Commercial Operation.

clearing in FCA 17 would be the prudent choice from a developer's perspective but would exacerbate the very risk that ISO-NE purports to be addressing with the delay.

H. Removal of the CASPR Test Price

Second, while the ISO proposes to set a cap of no more than 700 MW of Sponsored Policy Resources clearing through the RTR exemption during the two-year delay, it also eliminates the test price provisions from the CASPR Substitution Auction during this time.

Removal of the test price provision would allow an unknown quantity of SPRs to displace existing generation in FCA 17 and FCA 18. Removing the test price provision would allow any existing resource to clear in the FCA and then attempt to retire through participation in the Substitution Auction to get a severance payment that would be paid for by the Sponsored Policy Resources gaining entry to the market. No cap exists on the number of megawatts that may transact in the Substitution Auction and any such transactions would carry with them precisely the same concerns the ISO describes as the basis for the delay. In other words, an unknown quantity of SPRs could displace existing generation through this mechanism during the "transition" period, no different in effect from the immediate elimination of the MOPR; the only difference between the two would be that in the former there would be a transfer payment from the entering Sponsored Policy Resources to the retiring resources that would not occur in the latter.

ISO-NE appears to argue that this is not a risk it is concerned about because in the four-year history of CASPR only 54 MW of capacity has been transferred this way, without acknowledging that the only successful CASPR transaction occurred in the one year in which there was no test price provision. The ISO dismisses the possibility that CASPR might be successful during the two-year delay period with the removal of the test price provision.[68] And yet, they also state that the reason for eliminating the test price during the delay period is that "doing so may be a way to facilitate more participation by existing resources in the substitution auction."[69]

The transition mechanism filed by the ISO, including the elimination of the test price provisions, was developed by Vistra in the stakeholder process and ultimately sponsored by Dynegy, a subsidiary of Vistra, Calpine, and Nautilus.[70] It is instructive to go back to the source to see the original intent behind the inclusion of the test price elimination in the proposal.[71]

In Vistra's presentation to the Markets Committee, the removal of the test price was intended to "facilitate additional CASPR participation."[72] With FCA clearing prices in recent years being at historic lows, the presentation notes that "the test price has become an impediment to any existing resource being able to participate in the substitution auction" and was thus "limiting participation."[73] According to the ISO's 2021 CELT Report (2021–2030 Forecast Report of Capacity, Energy, Loads, and Transmission), the sponsors of this proposal are the Lead Participants of a total of 7.3 GW (nameplate) of generation in New England that will be treated as existing capacity in FCA 17, with a

[68] Transmittal Letter at 66 n.258.
[69] *Id.* at 68.
[70] Nautilus is a Related Person to Essential Power Newington, LLC and Revere Power, LLC, which are each shown as Lead Participants of existing gas-fired generators in Appendix A.
[71] Vistra, *MOPR Transition Proposal* (Oct. 21, 2021), https://www.iso-ne.com/static-assets/documents/2021/10/a02a_ii_mc_2021_10_21_vistra_draft_proposal.pptx.
[72] *Id.* at Slide 22.
[73] *Id.* at Slide 37.

summer capacity value of approximately 6.6 GW, as shown in Appendix A. All of this is natural gas-fired combined cycle generation (1.3 GW of this appears to be dual fuel) built between 1993 and 2004. If there are any market participants familiar with whether the test price has presented a barrier to participation in CASPR and whether its removal during this two-year transition period would allow them to meaningfully participate during that time, I expect these three participants are among them. Notably, these existing resources would be eligible to use the CASPR provisions over the two-year delay period to retire with a severance payment.

In FCA 16, just over 1 gigawatt of existing generation elected to submit a Substitution Auction Demand Bid and just shy of 4 gigawatts of new SPRs elected to submit Substitution Auction supply offers. Though none of these transactions cleared in FCA 16, the interest appears to be there. If the test price is removed, the volumes that could clear in the Substitution Auction during the delay period could eclipse the RTR exemption cap, leading to the same outcome that ISO-NE stated a desire to avoid. Perhaps this would even accelerate the risk ISO-NE is concerned about, by offering a payment to retiring resources that is limited to this two-year period.

In all past Substitution Auctions, existing resources considering retirement expected to have an unlimited number of future chances to exit the market through CASPR so there was no particular rush to make the trade in any given year. Yet with the proposed transition mechanism, a two-year clock has been started for these resources and they now have only two chances, in FCA 17 and FCA 18, to exit the market with a payment. That could be just the incentive some resources need to bid in a way that would clear during this transition. The ISO's support of the delay proposal appears to be predicated on the idea that it will prevent exactly these types of substitution transactions from occurring in large volumes in FCA 17 and FCA 18, yet the transition mechanism, if anything, appears to open the door wider for them to occur.

Q. If the Commission directs ISO-NE to refile its application, will ISO-NE have enough time to use the new tariff changes for FCA 17?

I. FCA 17 Auction Schedule

A. Yes. The current FCA 17 schedule, revised to address the cascading effect of delays to FCA 16, has the FCA 17 auction commencing on March 6, 2023, one month later than its original schedule.[74] Due to the delays that have already been made to the FCA 17 schedule, there is more time this year to finalize certain auction rules while minimizing any resulting auction schedule impact.

If the Commission issues an Order on May 27, 2022, directing ISO-NE to refile its tariff on or before July 28, 2022, and the Commission accepted the revised filing on or before September 26, 2022, ISO-NE could use the revised tariff to conduct FCA 17.

J. Accommodations For Retirement and Delist Bids

According to the current auction schedule, retirement and permanent delist bids are due by May 6, 2022, with the IMM's review of these bids ending on July 13, 2022. Following the IMM review, these resources will have through July 20, 2022, to elect conditional or unconditional treatment, after which the ISO will review for related reliability needs through September 20. These resources will then have until October 7 to decline their

[74] ISO-NE, *Forward Capacity Auction 17 Schedule – Capacity Commitment Period: 2026–2027* (Mar. 23, 2022), https://perma.cc/3R7W-EFQP.

capacity being retained for reliability, if identified for such retention. Meanwhile, the IMM will make its informational filing to the Commission on August 10.

Clearly the outcome of this proceeding and any revised tariff could influence the permanent and retirement delist decisions participants would wish to make over the course of this process. Some flexibility would be needed to allow these existing resources the ability to reflect such an eventuality in their bids and ensuing elections. ISO-NE resolved a similar situation last year, so a successful model for this type of flexibility is already in place.

ISO-NE and NEPOOL made their jump ball filing with alternative sets of ORTP values for FCA 16 on April 7, 2021 (Docket No. ER21-1637). This was after the March 12, 2021 close of the FCA 16 retirement and permanent delist bid window. The Commission's decision in that docket was requested by June 8, 2021, which was after June 3, 2021, when the IMM would conclude its review of the permanent and retirement delist bids. Due to the need to move forward in the process, the uncertainty about what set of ORTP rules would be applied to new resource entry, and the recognition that this could impact existing resources' permanent and retirement bid elections, the IMM provided the ability for existing capacity resources to submit flexible, contingent permanent and retirement delist bids for FCA 16.

This flexibility was detailed in a memo from the IMM to the NEPOOL Participants Committee on March 3, 2021, just seven business days before those retirement and permanent delist bids would be due.[75] From that memo, "IMM now clarifies how a Market Participant may submit Retirement De-List Bids, Permanent De-List Bids and test prices for FCA 16 by the submission deadline that are conditional upon the outcome of the ORTP jump ball regulatory proceeding. While Market Participants must commit to a delist bid submission by the deadline, Market Participants may submit a Retirement De-List Bid, Permanent De-List Bid and/or test price that is effective under one or more scenarios described below and may chose [sic] specific scenarios where no delist bid is to be applied."[76] The three scenarios were that (1) the Commission approved the ISO's proposal, (2) the Commission approved the NEPOOL proposal, and (3) the Commission rejected both or approved a combination of the proposals.

A similar approach to that which was used successfully last year could be applied to the FCA 17 process without changing any of the dates in the current FCA 17 schedule. The ISO's filing in this case, which begins the process of determining which offer floor price mitigation will apply for FCA 17, has been submitted 31 days **prior** to the close of the retirement and permanent delist bid window. In contrast, last year the equivalent filing that started the process of determining the FCA 16 ORTP values was made 26 days **after** the close of that delist bid window. As a result, the market would be in better shape this year to have earlier certainty around the outcome of the regulatory process and which set of retirement or permanent delist bids to use than last year when this process was successfully used.

[75] NEPOOL, *ISO-NE Memorandum to NEPOOL Participants Committee* (PDF p. 286) (Feb. 25, 2021), https://perma.cc/NS44-3M2V.
[76] *Id.*

K. Accommodations for New Resource Qualification

In addition to considering how this uncertainty impacts existing resources, there is also the new resource qualification process to consider. New capacity resources are required to submit their FCA 17 Show of Interest by June 6, 2022, one week after the Commission's decision has been requested in this proceeding. The outcome of this proceeding would not be expected to change anything regarding the contents of such Show of Interest submittals. New capacity resources must then submit their qualification packages by July 27, 2022, at which point ISO-NE's compliance proposal would be known, though potentially not yet approved and effective. Under the current Tariff, under the ISO-NE's filed delay proposal, and in the case of new resources that would not qualify for an exemption from the limited buyer side mitigation under the ISO's Markets Committee Proposal to stakeholders that did not include the delay, requests for resource-specific offer floor prices below the default FCA 17 ORTP values must be submitted as part of the qualification package along with supporting documentation. Were the Commission to reject the ISO's instant filing and direct them to re-file, such requests for individual offer floor prices and supporting documentation could be provided, as desired, by new resources as part of their qualification packages according to the current Tariff.

Under the ISO's Markets Committee Proposal that they brought through the stakeholder process, which did not include the delay, resources seeking an exemption from the limited buyer side mitigation must submit a Load-Side Relationship Certification and/or documentation demonstrating lack of incentive to exercise buyer-side market power. If the ISO accepts this certification and/or lack of incentive, the resource would not be subject to the limited buyer side market power mitigation. Were the Commission to direct

ISO to re-file its Tariff as described above, such a compliance filing could include a one-time provision for FCA 17 allowing for the submittal of these certifications and demonstrations within one week of the Commission's acceptance of that filing, by October 3, 2022.

The ISO would notify new capacity resources of their qualification acceptance/denial and their offer floor price on November 10, 2022, 45 days after the Commission might accept a compliance filing as described above. Under the ISO's Markets Committee Proposal without the delay, the ISO would also include their determination as to whether the resource satisfies any of the buyer side market power exemptions. Under the hypothetical compliance filing just described, the ISO would have 38 days between the submittal of the certifications or demonstrations and the notification of qualification to determine which new resources would be exempted from the buyer side mitigation under these provisions. Also, during this time, the IMM would need to determine which other resources would be exempt from the limited buyer side mitigation, such as resources with less than 5 MW of capacity or passive demand resources. Had a resource that was determined to be exempt during this time previously submitted a request for an individual offer floor price as part of its qualification package, that request would become moot. Finally, for those resources to which the limited buyer side mitigation ultimately applied, the IMM would have been given all the necessary information to determine an offer floor price as part of the qualification package.

It therefore appears that ISO would be able to apply the new Tariff for the FCA 17 qualification process with little impact on the auction schedule laid out, except for creating a one-time window for the submittal of certifications and demonstrations that would otherwise normally be submitted along with the qualification package.

Q. If the Commission directs ISO-NE to refile its application, will ISO-NE be required to recalculate Cost of New Entry ("CONE") and Net CONE as part of its revised filing?

L. Calculation of CONE and Net CONE

A. No. As part of ISO-NE's Markets Committee Proposal, which did not include a transition mechanism, it calculated an adjustment to the CONE and Net CONE values for FCA 17. This is the only substantive component of that Markets Committee Proposal that was not included in ISO's ultimate filing to the Commission. Section III.13.2.4.2(b) of that Markets Committee Proposal read, "Prior to applying the annual adjustment described in this Section III.13.2.4.2 for the Capacity Commitment Period beginning on June 1, 2026, CONE will be increased by $1.391/kW-month and Net CONE will be increased by $1.197/kW-month to reflect the elimination of the Offer Review Trigger Price mechanism applicable to New Capacity Resources in the Forward Capacity Market."[77] This adjustment was the result of an evaluation performed by the External Market Monitor that underwent extensive stakeholder review. Were the Commission to direct ISO-NE to submit a revised filing without the delay, such as the proposal that they brought through the stakeholder process, I believe that it would be appropriate for ISO-NE to include this piece of its Markets Committee Proposal in its revised tariff filing.[78]

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[77] Markets Committee Proposal.
[78] *Id.* § III.13.2.4.2 (Interim-Year CONE and Net CONE Adjustment).

Otherwise, the Tariff currently requires ISO-NE to recalculate CONE and Net CONE at least once every three years.[79] The next three-year adjustment is required by FCA 19, though ISO has indicated that it may file a proposal to delay this recalculation until FCA 21.[80]

Q. Does that complete your testimony?

A. Yes.

[79] *Id.* § III.A.21.1.2 (Calculation of Offer Review Trigger Prices).
[80] ISO-NE Update 2022 Annual Work Plan Presentation, at PDF p. 200, Slide 8.

APPENDIX A

ASSET NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	IN-SERVICE DATE	LEAD PARTICIPANT NAME	RSP AREA	NAMEPLATE (MW)	WINTER SCC (MW) Jan 1, 2021	EXPECTED SUMMER PEAK SCC (MW) Jul 1, 2021
MASS POWER	CC	NG		7/1/1993	Dynegy Marketing and Trade, LLC	WMA	270.655	279.800	248.217
ANP-BLACKSTONE ENERGY 1	CC	NG		6/7/2001	Dynegy Marketing and Trade, LLC	RI	289.000	280.751	242.157
ANP-BLACKSTONE ENERGY 2	CC	NG		7/13/2001	Dynegy Marketing and Trade, LLC	RI	289.000	278.812	240.227
LAKE ROAD 1	CC	NG		3/15/2002	Dynegy Marketing and Trade, LLC	CT	289.000	295.032	276.807
LAKE ROAD 2	CC	NG		3/15/2002	Dynegy Marketing and Trade, LLC	CT	289.000	307.881	274.126
LAKE ROAD 3	CC	NG		5/22/2002	Dynegy Marketing and Trade, LLC	CT	289.000	295.108	272.874
MILFORD POWER 1	CC	NG		2/12/2004	Dynegy Marketing and Trade, LLC	SWCT	289.000	295.647	270.340
MILFORD POWER 2	CC	NG		5/3/2004	Dynegy Marketing and Trade, LLC	SWCT	289.000	289.707	263.590
ANP-BELLINGHAM 1	CC	NG		10/24/2002	Dynegy Marketing and Trade, LLC	RI	289.000	299.779	260.596
ANP-BELLINGHAM 2	CC	NG		12/28/2002	Dynegy Marketing and Trade, LLC	RI	289.000	298.604	261.569
MAINE INDEPENDENCE STATION 1	CC	NG		5/1/2000	Dynegy Marketing and Trade, LLC	BHE	275.655	272.347	248.019
MAINE INDEPENDENCE STATION 2	CC	NG		5/1/2000	Dynegy Marketing and Trade, LLC	BHE	275.655	272.347	248.019
WESTBROOK ENERGY CENTER G1	CC	NG		4/13/2001	Calpine Energy Services, LP	SME	276.548	285.903	267.578
WESTBROOK ENERGY CENTER G2	CC	NG		4/13/2001	Calpine Energy Services, LP	SME	276.548	285.903	267.578
FORE RIVER 11	CC	NG	DFO	8/4/2003	Calpine Energy Services, LP	SEMA	436.165	403.005	356.700
FORE RIVER 12	CC	NG	DFO	8/4/2003	Calpine Energy Services, LP	SEMA	436.165	403.005	356.700
GRANITE RIDGE ENERGY 1A	CC	NG		4/1/2003	Calpine Energy Services, LP	NH	395.250	369.636	331.046
GRANITE RIDGE ENERGY 1B	CC	NG		4/1/2003	Calpine Energy Services, LP	NH	395.250	369.636	331.046
EP NEWINGTON ENERGY, LLC	CC	NG	DFO	9/18/2002	Essential Power Newington, LLC	NH	605.823	633.700	559.668
BRIDGEPORT ENERGY 1	CC	NG		8/1/1998	Revere Power, LLC	SWCT	536.350	577.128	490.127
TIVERTON POWER	CC	NG		8/18/2000	Revere Power, LLC	SEMA	273.700	299.746	264.827
RUMFORD POWER	CC	NG		10/16/2000	Revere Power, LLC	ME	272.850	269.091	244.281
						Total:	7,327.613	7,362.568	6,576.092

EXHIBIT B

Testimony of Dr. Kathleen Spees and Dr. Samuel A. Newell

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
	)	
ISO New England Inc.	**)**	**Docket No. ER22-1528**
	)	
	)	

WRITTEN TESTIMONY OF

DR. KATHLEEN SPEES and DR. SAMUEL A. NEWELL

Economic Impacts of the Minimum Offer Price Rule
within the ISO-NE Capacity Market

I. INTRODUCTION AND QUALIFICATIONS

Our names are Dr. Kathleen Spees and Dr. Samuel A. Newell. We are employed by The Brattle Group as Principals. We submit this affidavit on behalf of RENEW Northeast, Natural Resources Defense Council, Sierra Club, Conservation Law Foundation, Acadia Center, the Environmental Defense Fund, Sustainable FERC Project, Massachusetts Climate Action Network, PowerOptions, E2 (Environmental Entrepreneurs), and American Clean Power Association (collectively "Clean Energy and Consumer Advocates").

Our qualifications as experts derive from our extensive experience evaluating capacity markets and related market design questions. Our experience working for system operators across North America and internationally has given us a broad perspective on the practical implications of nuanced capacity market design rules under a range of different economic and policy conditions.[1]

We are familiar with the Independent System Operator of New England ("ISO-NE") Forward Capacity Market ("FCM"), including the history of the Minimum Offer Price Rule ("MOPR")

[1] We have worked with regulators, market operators, and market participants on matters related to resource adequacy and investment incentives in PJM Interconnection, ISO New England, New York, Ontario, Alberta, California, Texas, Midcontinent ISO, Italy, Russia, Greece, Singapore, and Australia.

and its predecessor rule the Alternative Pricing Rule ("APR") from the conception of the FCM up through the current form as implemented along with the Competitive Auctions with Sponsored Policy Resources ("CASPR") mechanism. We have supported ISO-NE, the New England Power Pool ("NEPOOL"), and stakeholders in many aspects of FCM design and evolution. Examples of our experience include a review of FCM effectiveness and performance including an assessment of the APR (conducted alongside ISO-NE's internal market monitoring unit);[2] the estimation of the Offer Review Trigger Prices ("ORTPs") utilized in the implementation of the MOPR;[3] the development of a system-wide sloping demand curve to replace the prior vertical demand curve and price floor;[4] estimation of the Net Cost of New Entry ("Net CONE") parameter utilized in FCM;[5] development of a range of market-based solutions for addressing winter reliability needs; and support to several NEPOOL and New England state efforts to align the FCM with states' policy requirements.[6]

We have examined the economic impacts of MOPR variations in several other capacity markets as well. We have previously submitted testimony before the Federal Energy Regulatory Commission ("FERC") on the economic effects of MOPR in both PJM Interconnection ("PJM") and New York Independent System Operator ("NYISO") capacity markets, included as Attachment A to this testimony. In New York, we have conducted analyses on behalf of the New York State Energy Research and Development Authority ("NYSERDA") and the New York State Department of Public Service ("NYSDPS") to analyze the costs of Buyer Side

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[2] *See* Sam Newell, Metin Celebi, & Attila Hajos, *Review of the Forward Capacity Market Auction Results and Design Elements*, ISO-NE Market Monitoring Unit (June 2009), https://www.brattle.com/wp-content/uploads/2017/10/6212_iso_ne_internal_market_monitoring_unit_review_june_5_2009.pdf.

[3] *See* Samuel A. Newell, J. Michael Hagerty, & Quincy X. Liao, *2013 Offer Review Trigger Prices Study*, The Brattle Group (Oct. 2013), https://www.brattle.com/wp-content/uploads/2017/10/6095_2013_offer_review_trigger_prices_study_newell_hagerty_liao_isone_oct_2013.pdf.

[4] *See* Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of ISO New England Inc. Regarding A Forward Capacity Market Demand Curve (Apr. 1, 2014), https://www.brattle.com/wp-content/uploads/2021/08/939_brattle_system_demand_curve_testimony_newell_spees_0414.pdf.

[5] *See* Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve (Apr. 1, 2014), https://www.brattle.com/wp-content/uploads/2021/08/967_testimony_of_dr._samuel_a._newell_and_mr._christopher_d._ungate_on_behalf_of_iso_ne_inc._040114.pdf.

[6] *See* Kathleen Spees, *The Integrated Clean Capacity Market*, The Brattle Group (Oct. 1, 2020), https://www.brattle.com/wp-content/uploads/2021/05/20353_the_integrated_clean_capacity_market.pdf; Kathleen Spees et al., *A Dynamic Clean Energy Market in New England*, The Brattle Group (Nov. 2017), https://www.brattle.com/wp-content/uploads/2021/06/11819_a_dynamic_clean_energy_market_in_new_england-1.pdf.

Mitigation and potential expansions thereof, and to evaluate resource adequacy alternatives.[7] In PJM we have developed several studies and testimonies related to the MOPR, including a 2012 testimony on behalf of the Competitive Markets Coalition of generating companies seeking to refine and strengthen PJM's MOPR in its original purpose to prevent and mitigate the exercise of buyer market power;[8] a 2018 testimony on the need for competitive and self-supply exemptions to MOPR;[9] a 2020 testimony on behalf of PJM on developing economic estimates of offer floor prices to implement its MOPR rules; and studies on behalf of the New Jersey Board of Public Utilities ("NJ BPU") and the Maryland Energy Administration ("MEA") to analyze the costs of MOPR and to assess alternative approaches for supporting resource adequacy in those states.[10] In Alberta, Ontario, and Singapore, we have supported the market operators to develop capacity market rules to identify and prevent the exercise of buyer side market power in their proposed implementations of capacity markets.

Dr. Spees is an economic consultant with expertise in wholesale electric energy, capacity, and ancillary service market design and analysis. She earned a Ph.D. in Engineering and Public Policy, an M.S. in Electrical and Computer Engineering from Carnegie Mellon University, and a B.S. in Mechanical Engineering and Physics from Iowa State University (CV attached as Attachment B). Dr. Newell is an economist and engineer with 23 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and ISO/RTO market designs. He earned a Ph.D. in Technology Management and Policy from the Massachusetts

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[7] *See* Kathleen Spees, Samuel Newell, & John Imon Pedtke, *Qualitative Analysis of Resource Adequacy Structures for New York*, The Brattle Group (May 19 2020), http://www.brattle.com/wp-content/uploads/2021/05/18987_qualitative_analysis_of_resource_adequacy_structures_for_new_york.pdf.

[8] The Competitive Markets Coalition's Supporting Comments, at Attach. A, Affidavit of Dr. Samuel A. Newell on Behalf of the "Competitive Markets Coalition" Group Of Generating Companies (supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model), Docket No. ER13-535-000 (Dec. 28, 2012), Accession No. 20121228-5253 ("Affidavit of Dr. Samuel A. Newell on Behalf of the Competitive Markets Coalition").

[9] Comments of Dominion Energy Services, Inc., at Affidavit of Kathleen Spees and Samuel A. Newell In Support of Dominion Energy Services, Inc., Regarding the Need for a Self-Supply Exemption from Minimum Offer Price and Other Policy-Supported Resource Rules, Docket Nos. EL16-49-000 et al. (Oct. 2, 2018), Accession No. 20181002-5292.

[10] *See Alternative Resource Adequacy Structures for New Jersey: Staff Report on the Investigation of Resource Adequacy Alternatives, Docket #EO20030203*, Staff of NJ BPU and The Brattle Group (June 2021), https://nj.gov/bpu/pdf/reports/NJ%20BPU%20RA%20Investigation%20(Final).pdf; and Kathleen Spees, Sam Newell et al., *Alternative Resource Adequacy Structures for Maryland: Review of the PJM Capacity Market and Options for Enhancing Alignment with Maryland's Clean Electricity Future*, The Brattle Group (Mar. 2021), https://energy.maryland.gov/Reports/Alternative%20Resource%20Adequacy%20Structures%20for%20Maryland%20Final%20Brattle%20Study%20March%202021.pdf.

Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and a B.A. in Chemistry and Physics from Harvard College (CV attached as Attachment C).

I. THE APPLICATION OF MOPR TO SPONSORED POLICY RESOURCES IN ISO-NE IS BASED ON FLAWED REASONING

As we testified in our recent filings before FERC related to similar rules in PJM and NYISO, the application of a MOPR to sponsored policy resources is based on flawed economic reasoning.[11] As we explain more fully in those prior testimonies:

- The majority of the policies in question across the ISO-NE footprint address a well-understood market failure to reflect environmental and public health externalities. The environmental value of policy-supported resources should not be considered an illegitimate distortion of markets that must be excluded, but rather a correction that is needed to achieve a more efficient outcome;
- The "correct" price for capacity is one that aligns supply and demand, not the price that would prevail in the absence of state policies as ISO-NE's MOPR rule is presently designed to produce in the primary Forward Capacity Auction ("FCA");
- Capacity markets with sloping demand curves cannot simultaneously produce low prices and capacity procurement levels insufficient to meet the Installed Capacity Requirement ("ICR");
- Merchant generation investors operate in a market and regulatory context that has always required them to face uncertainties associated with a wide range of energy and environmental regulations at the federal, state, and local levels. These policies and associated economic subsidies have influenced the resource mix (some in favor of incumbent fossil resources and others in favor of clean energy resources). Merchant investors should never have expected to be indemnified against risks associated with these policies (nor should they be required to return revenues to customers when policy changes favor their own investments); and

[11] To review a more comprehensive discussion of our economic analysis of MOPR, see Attachment A: PJM Testimony (Written Test. of Dr. Kathleen Spees and Dr. Samuel A. Newell: Economic Impacts of the Expansive Minimum Offer Price Rule within the PJM Capacity Market Docket), Docket No. ER21-2582-000 (2021) ("Brattle PJM Aff."), Accession No. 20210827-5205; and Clarification of Written Testimony Submitted by Dr. Kathleen Spees and Dr. Samuel Newell, Docket No. ER21-2582-000 (Sept. 13, 2021), Accession No. 20210914-5029).

- Broad application of MOPR to policy resources has amplified (not mitigated) the regulatory risks affecting capacity investments.

These same flaws apply equally in ISO-NE's FCM.

II. APPLYING THE MOPR TO SPONSORED POLICY RESOURCES IMPOSES UNECONOMIC EXCESS COSTS ON CONSUMERS AND SOCIETY AS A WHOLE

The ISO-NE's current MOPR requires policy resources to offer into the capacity market at a higher price than they otherwise would, which can prevent these policy resources from clearing in the FCA even if they will be built anyway and contribute to resource adequacy. The ISO-NE market has aimed to mitigate or balance the effect of excluding policy resources via MOPR through its CASPR mechanism for a secondary auction that allows MOPR-excluded resources to pay for and take on the capacity obligations of FCA-cleared resources. In this testimony, we do not aim to describe and critique CASPR, other than to acknowledge and agree with ISO-NE's statement that "[a]pplication of the MOPR going forward, however, will likely exclude large amounts of state-sponsored capacity from entering the Forward Capacity Market, and CASPR has not proven to date that it will facilitate their entry." [12] Regardless of CASPR's performance to clear or not clear policy resources in the secondary auction, our focus in this testimony is on the more central issue that policy resources should not be subject to MOPR rules in the first instance.

Excluding policy resources from clearing in the FCM causes the capacity auction to perceive a supply "gap" that it will seek to fill by clearing other, higher-cost capacity resources while setting a higher clearing price. Applying MOPR therefore causes the auction to retain more existing capacity resources (such as existing steam plants that would otherwise retire) and/or attract new investments (such as new gas-fired power plants that would not otherwise be built). The total amount of capacity available and operating will therefore exceed the amount needed to satisfy the ICR that the capacity market was designed to meet.

[12] ISO Filing, MOPR Elimination Transmittal Letter, at 6 (Mar. 31, 2022) ("Transmittal Letter"), Accession No. 20220331-5296.

Excluding policy resources from clearing the capacity market will produce inefficient market outcomes compared to a market with a narrower MOPR focused only on preventing manipulative price suppression. These inefficiencies include:

- Preventing capacity resources from clearing the primary capacity auction;
- Causing an oversupply of capacity (when considering the total volume of capacity that is cleared plus the volume that exists but remains uncleared);
- Producing prices that are higher than the economically-efficient level that aligns with the intersection of supply and demand;
- Imposing excess customer costs associated with excess capacity payments; and
- Imposing societal deadweight losses associated with inefficient excess supply.

We have estimated the likely size and uncertainty range of these inefficient outcomes in the separate PJM and NYISO contexts.[13] We have not estimated the magnitude of these same impacts in the ISO-NE context.

The specifics of how ISO-NE's MOPR provisions have come about, are presently implemented, and would change under ISO-NE's proposed two-year Transition Mechanism differ from the specifics in New York and PJM. Under current ISO-NE MOPR provisions, the broad application of MOPR applies to all new resources (not just policy resources) and so has the potential to prevent additional merchant resources from clearing the market compared to NYISO and prior PJM rules. The current ISO-NE and prior PJM rules apply technology-specific offer floors that can be higher than the default MOPR floor in NYISO, and so will tend to exclude more resources. If the secondary auction under ISO-NE's CASPR had proven to clear more policy resources, that could have reduced some of the resulting supply excess and deadweight loss (though in practice, this has not happened). And finally, under the ISO-NE proposed Transition Mechanism, the volume of resources excluded by the broad MOPR would be reduced by the proposed 700 MW policy resource exemption. Additionally, the scale of policy resources that will be developed differs substantially across regions and among states within each region.

[13] We estimated excess consumer costs of $1.7 billion per year by 2030 in PJM and $1.3 to $2.8 billion per year in NYISO. *See* Attachment A for the details of these consumer cost impact estimates, as well as our estimates of the volume of excluded capacity, price impacts, and deadweight loss impacts.

These differences in how the broad MOPR is or is proposed to be implemented in ISO-NE serve to affect the volume of resources excluded by the MOPR, with commensurate effects on the magnitude of inefficiencies and excess consumer costs induced by the broad MOPR. The size of each market, underlying economic fundamentals, and pace of policy resources being developed will also have a substantial impact on the size of economic inefficiencies that can be caused by applying MOPR to policy resources. However, the nature and direction of the economic inefficiencies are the same in all cases.

III. MOPR SHOULD BE APPLIED FOR THE NARROW PURPOSE OF PREVENTING THE ABUSE OF MARKET POWER

The original purpose of the APR (the predecessor rule to the current MOPR) was to prevent manipulative price suppression by large buyers.[14] As we discuss further in Attachment A, the MOPR should be maintained only for this narrow original purpose of addressing manipulative price suppression. The MOPR should not be applied to state policy resources. A more appropriately targeted MOPR will enable the capacity market to support competition, produce accurate pricing signals that align with market fundamentals, and attract investment when needed.

IV. NEW ENGLAND DOES FACE CRITICAL RELIABILITY CHALLENGES, BUT MOPR IS NOT AN EFFECTIVE OR EFFICIENT SOLUTION

The New England region is facing critical reliability challenges, as have been extensively documented by ISO-NE and state agencies. The most urgent of these challenges relates to the need to ensure reliability throughout the winter season when cold snaps may severely limit the amount of natural gas available and firm or on-site fuel supplies are limited.[15] Another critical issue over the coming years will be the need to adopt an improved framework to more accurately

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[14] Though various parties to the docket described the purpose of the APR differently, mitigating the potential for exercise of monopsony market power was the rationale eventually accepted by the FERC. *See* ISO-NE's Explanatory Statement in Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration and Settlement Agreement Resolving All Issues, Docket Nos. ER03-563-030, -055 (Mar. 6, 2006), Accession No. 20060308-0017 and FERC's Order Accepting Proposed Settlement Agreement, Docket Nos. ER03-563-030, -055 (June 16, 2006), Accession No. 20060616-3037.

[15] For example, see the brief summary of these challenges and associated analyses provided in letters exchanged between the Connecticut Department of Energy and Environmental Protection and ISO-NE, *Fuel Security in New England for Winter 2021-22*, (Dec. 17 and 21, 2021), https://www.iso-ne.com/static-assets/documents/2022/01/isone_ct_deep_combined_ltrs.pdf.

measure the resource adequacy contributions of all resources, an issue that is the subject of an upcoming NEPOOL reform effort.[16] In both cases, these reliability challenges will need to be addressed by market reforms that are focused on addressing the identified challenges. Examples of the most obvious reforms to consider include:

- More accurately measuring reliability needs in the New England system through improved reliability modeling that more accurately accounts for winter reliability drivers, resource intermittency, fuel interruption risks, weather-driven outages, and correlations of these reliability drivers with consumer demand;
- More accurately measuring reliability contributions of different resources and technologies, including separate measurements in the summer and winter seasons after accounting for issues such as fuel supply access, intermittency, and weather-driven resource availability;
- Enhancing the FCM to become a full seasonal capacity market that ensures both summer and winter reliability needs are fulfilled; and
- Enhancing energy and ancillary service products to align with operational uncertainties such as forecast errors in an evolving resource mix.

These and other reforms to address reliability challenges have the common feature that they begin with a clearly articulated reliability need. The most effective market-based solution will be one that competitively procures sufficient supply commitments to meet the defined reliability need.

If a transitional period is required to implement some aspects of any such long-term solution, the transition mechanism should similarly be focused on solving the identified problem. For example, if it will take several years to develop the most accurate estimate of winter reliability needs and resources' contributions to the need, a less precise preliminary estimate can be used temporarily. If there is a concern that resources' capacity ratings are overstated on a fleet-wide basis, then the ICR could be temporarily increased to account for an approximate estimate of the aggregate estimation error. Under both of these examples, the transition mechanism would more effectively address the nature and size of the identified reliability gap.

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[16] *See* ISO-NE, Updated 2022 Annual Work Plan (Apr. 7, 2022), https://www.iso-ne.com/static-assets/documents/2022/04/2022_awp_update_for_04_07_22_pc.pdf.

The ISO-NE proposed Transition Mechanism to extend the present MOPR is not an efficient nor effective means to address either of the two most urgent reliability concerns facing the region. Directionally, it is correct that extending MOPR will maintain a larger excess of supply than eliminating MOPR immediately, which could directionally improve reliability. However, there is no proposed mechanism to ensure that the excess resources retained will materially contribute to the most immediate concern of winter reliability, leaving open the possibility that winter reliability concerns could remain unaddressed even while excess capacity is procured under the (summer-focused) FCM construct. If the excess resources are highly susceptible to winter fuel shortages or cold-weather-driven outages, current winter reliability challenges could remain or worsen throughout transition period. Even if winter needs remain unmet, the region could still be retaining costly excess supply relative to summer reliability needs since there is no upper bound on the total volume of excess supply that could be induced via MOPR throughout the transition period. Finally, even after the conclusion of the transition period, ISO-NE's proposal does not include a long-term solution to define and meet winter resource adequacy needs.

MOPR is not an effective or efficient means to address the most urgent reliability challenges in New England because it was designed for an entirely different purpose.

V. CERTIFICATION

I hereby certify that I have read the filing signed and know its contents are true as stated to the best of our knowledge and belief. I possess full power and authority to sign this filing.

Respectfully Submitted,

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April 21, 2022

<u>ATTACHMENT A</u>

PJM Testimony (Written Test. of Dr. Kathleen Spees and Dr. Samuel A. Newell: Economic Impacts of the Expansive Minimum Offer Price Rule within the PJM Capacity Market Docket), Docket No. ER21-2582-000 (2021), Accession No. 20210827-5205; and Clarification of Written Testimony Submitted by Dr. Kathleen Spees and Dr. Samuel Newell, Docket No. ER21-2582-000 (Sept. 13, 2021), Accession No. 20210914-5029

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection L.L.C., **Revisions to Application of Minimum Offer Price Rule**	))))	**Docket No. ER21-2582-000**

WRITTEN TESTIMONY

OF

DR. KATHLEEN SPEES AND DR. SAMUEL A. NEWELL

Economic Impacts of the Expansive Minimum Offer Price Rule within the PJM Capacity Market

Our names are Dr. Kathleen Spees and Dr. Samuel A. Newell. We are employed by The Brattle Group as Principals. We submit this affidavit on behalf of the Natural Resource Defense Council, the Sustainable FERC Project, Earthjustice, Sierra Club, and Union of Concerned Scientists.

Our qualifications as experts derive from our extensive experience evaluating capacity markets and related market design questions. Our experience working for system operators across North America and internationally has given us a broad perspective on the practical implications of nuanced capacity market design rules under a range of different economic and policy conditions.[1] We have extensive experience supporting assessment and refinement of all aspects of the PJM Capacity Market; we have supported PJM Interconnection (PJM) by conducting every one of its periodic reviews of its capacity market and by comparing its capacity market with resource adequacy design alternatives.[2]

We are familiar with the history of the Minimum Offer Price Rule (MOPR) in PJM from its conception up through the current Expanded MOPR (MOPR-Ex) form. In 2011, as part of our

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1 We have worked with regulators, market operators, and market participants on matters related to resource adequacy and investment incentives in PJM Interconnection, ISO New England, New York, Ontario, Alberta, California, Texas, Midcontinent ISO, Italy, Russia, Greece, Singapore, and Australia.

2 See our four independent reviews of PJM's capacity market and associated design parameters published in 2008, 2011, 2014, and 2018. The most recent of these is: Samuel A. Newell, David Luke Oates, Johannes P. Pfeifenberger, Kathleen Spees, J. Michael Hagerty, John Imon Pedtke, Matthew Witkin, and Emily Shorin, *Fourth Review of PJM's Variable Resource Requirement Curve*, prepared for PJM Interconnection L.L.C., April 19, 2018. See also, Johannes Pfeifenberger, Kathleen Spees, and Adam Schumacher, *A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs*, prepared for PJM Interconnection L.L.C., September 2009.

triennial review for PJM, we recommended competitive and self-supply exemptions.[3] In 2012, Dr. Newell submitted testimony on behalf of the Competitive Markets Coalition of generating companies seeking to apply those recommendations but strengthen PJM's MOPR in its original purpose to prevent and mitigate the exercise of buyer market power.[4] In 2018, we testified on the need for competitive and self-supply exemptions to MOPR.[5] In 2020, Dr. Newell submitted testimony to the Federal Energy Regulatory Commission (FERC) on behalf of PJM on developing economic estimates of offer floor prices to implement its MOPR rules. Most recently, we have conducted analyses on behalf of the New Jersey Board of Public Utilities (NJ BPU) and the Maryland Energy Administration (MEA) to analyze the costs of MOPR-Ex and to assess alternative approaches for supporting resource adequacy in those states.[6]

We have examined the economic impacts of MOPR variations in several other capacity markets as well. In New York, we have conducted analyses on behalf of the New York State Energy Research and Development Authority (NYSERDA) and the New York State Department of Public Service (NYSDPS) to analyze the costs of Buyer Side Mitigation and potential expansions thereof, and to evaluate resource adequacy alternatives. In Alberta, Ontario, and Singapore, we have supported the market operators to develop capacity market rules to identify and prevent the exercise of buyer side market power in their proposed implementations of capacity markets.

Dr. Spees is an economic consultant with expertise in wholesale electric energy, capacity, and ancillary service market design and analysis. She earned a Ph.D. in Engineering and Public Policy, an M.S. in Electrical and Computer Engineering from Carnegie Mellon University, and a B.S. in Mechanical Engineering and Physics from Iowa State University. Dr. Newell is an economist and engineer with 23 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and ISO/RTO market designs. He earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and a B.A. in Chemistry and Physics from Harvard College.

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3 Pfeifenberger, Newell, Spees, Hajos, and Madjarov, *Second Performance Assessment of PJM's Reliability Pricing Model: Market Results 2007/08 through 2014/15*, prepared for PJM Interconnection LLC, August 26, 2011.

4 FERC Docket No. ER13-535-000, filed "The Competitive Markets Coalition's Supporting Comments, at Attach. A, Affidavit of Dr. Samuel A. Newell on Behalf of the 'Competitive Markets Coalition' Group Of Generating Companies," supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model, December 28, 2012 ("Affidavit of Dr. Samuel A. Newell on Behalf of the Competitive Markets Coalition").

5 Affidavit of Kathleen Spees and Samuel A. Newell Regarding the Need for a Self-Supply Exemption from Minimum Offer Price and Other Policy-Supported Resource Rules, Calpine Corporation, et al. v. PJM Interconnection, L.L.C, FERC Docket Nos. EL16-49-000, October 2, 2018.

6 See Attachment A.

See also Kathleen Spees, Travis Carless, Walter Graf, Sam Newell, *et al.*, *Alternative Resource Adequacy Structures for Maryland: Review of the PJM Capacity Market and Options for Enhancing Alignment with Maryland's Clean Electricity Future*, prepared for Maryland Energy Administration, March 2021.

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Executive Summary

The original and proper economic purpose of the minimum offer price rule (MOPR) is to protect the capacity market from the exercise of buy-side market power. Buy-side market power can occur when a large net buyer of capacity develops (or contracts to develop) excess capacity resources and offers the additional supply into the market below cost in order to suppress market clearing prices.[7] By taking a loss on that small "uneconomic" position, a large net buyer could then benefit from a much larger short position in the market. The MOPR was designed to prevent this behavior. The concept was to ensure that entities with the incentive and ability to engage in manipulative price suppression would be unable to do so by requiring their capacity market offers to reflect full resource costs. Thus uneconomic new resources sponsored by large net buyers would fail to clear (or would set prices at a higher level) and prevent the would-be gaming entity from achieving the benefits of manipulative price suppression.[8]

More recently, the current Expansive MOPR (MOPR-Ex) has repurposed the original MOPR to exclude from the capacity market resources that earn revenues for supporting states' environmental and other policy goals. Resources developed to meet policy goals add supply in the market, which can cause lower capacity prices and displace other types of capacity that might otherwise have been built or retained. Advocates of MOPR-Ex assert that these outcomes unfairly reduce revenues to merchant capacity suppliers, undermine incentives for capacity investments, and threaten system reliability. Applying MOPR to policy resources, they assert, restores capacity prices to the "correct" level that would prevail in the absence of state policies. These arguments rest on flawed economic logic.

There is no sensible economic rationale for applying MOPR to all policy resources. States have many reasons to support capacity supply resources including to limit the harms of climate change, address environmental externalities, improve public health, create jobs, and support economic growth. The policy support awarded to such resources reflects their contributions to state policy objectives; they create environmental attributes or other benefits that states wish to buy and are remunerated for producing those benefits. Such resources are not "uneconomic" because their value is not derived from a scheme of manipulative capacity price suppression. Further, MOPR-Ex has not "leveled the playing field" because it fails to address the environmental and public health externalities that are the primary reason for most of the PJM states' policies in question. MOPR-Ex also does not attempt to undo the effects of all local, state, and federal policies that have always shaped the resource mix, including supporting the development of existing fossil plants and reducing the delivered cost of fossil fuels.

Applying MOPR to policy resources can prevent them from clearing the capacity market, with several undesirable effects. First, it can deprive policy resources of revenues commensurate with the capacity value they provide. Second, it favors the retention and development of uneconomic excess capacity supply that is not needed for reliability. Third, it distorts market clearing prices upward from the level corresponding to actual supply-demand conditions and thereby effectuates a wealth transfer from customers to incumbent suppliers. And fourth, applying MOPR to policy resources will eventually render the market unsustainable as these distortions become larger over time as states across the PJM

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7 *See PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 at P 103 (2006).

8 In addition to its buy-side market power provisions to protect the market from uncompetitively low prices, the PJM capacity market also has supply-side market power provisions to protect the market from uncompetitively high prices. Absent protections, large sellers of capacity could offer a small amount of capacity at a high price above their costs, intentionally fail to clear (losing money on a small transaction), and benefit from a higher capacity price (gaining money on a much larger position). To prevent such economic withholding, offer caps can be placed on large capacity sellers. Must-offer requirements also apply, to prevent physical withholding.

footprint pursue their clean energy and other policy objectives. Across the PJM footprint, 92% of customer demand is within states that have adopted renewable portfolio standard (RPS) or other clean energy requirements whose resources could be excluded by MOPR-Ex.[9] Customers in states with the largest policy resources may face the greatest share of the costs from MOPR-Ex (but even customers in states with no policy resources will bear the costs of higher capacity prices caused by MOPR-Ex). Several PJM states have among the most ambitious climate goals in the country, including Washington DC at 100% renewable by 2032, Virginia at 100% renewable by 2045/2050, New Jersey at 100% economy-wide clean energy by 2050, Delaware at 40% renewable by 2035, Maryland at 50% renewable by 2030, and Illinois considering 100% clean energy as early as 2030.[10] The end state of applying MOPR to clean energy resources in these states is absurd: it would be a capacity market that excludes a large majority of the fleet, with market clearing outcomes having no relationship to the physical reality of the grid mix.

In the present docket, PJM has proposed to replace MOPR-Ex with a more focused MOPR.[11] For policy resources, PJM proposes to substantially narrow the circumstances when MOPR could be applied so as to explicitly exempt resources supported under all existing state policies and by any future state policy mechanisms similar to those in common use across the PJM footprint. For non-policy resources, the MOPR will only be applied to resources owned by or contracted to large net buyers, and only if the buyer is deemed to have the incentive and ability to exercise buy-side market power.

PJM's proposed narrow MOPR should produce reliable and efficient capacity market outcomes that align pricing with supply-demand fundamentals and eliminate large inefficiencies associated with the current MOPR-Ex. If PJM's proposal is implemented, the capacity market will once again be able to fulfill its role to support economically efficient entry and exit decisions among a wide range of public and private actors across the regional footprint.

The Application of MOPR to Policy Resources Is Based on Flawed Economic Reasoning

In its filing, PJM explains why the current MOPR-Ex is unnecessary and will substantially erode the efficacy and efficiency of its capacity market. We agree with PJM's analysis of these flaws.

We supplement PJM's arguments with our own economic analysis of MOPR-Ex. We further explain why the rationale for applying MOPR to policy resources in the first place was based on incomplete and flawed economic logic. A corrected economic analysis should consider that:

- The majority of the policies in question across the PJM footprint address a well-understood market failure to reflect environmental and public health externalities. The environmental value of policy-supported resources should not be considered an illegitimate distortion of markets that must be excluded, but rather a correction that is needed to achieve a more efficient outcome;
- The "correct" price for capacity is one that aligns supply and demand, not the price that would prevail in the absence of state policies as MOPR-Ex is presently designed to produce;

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[9] Eleven of the 14 PJM states and the District of Columbia have RPS requirements; Kentucky, Tennessee, and West Virginia do not. Calculated from Monitoring Analytics, Data, Percentage of PJM Load by State, 2021.

[10] *See* PJM-EIS, "Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States," and "What is the Clean Energy Jobs Act," Illinois Citizens Utility Board.

[11] Letter to Kimberly D. Bose from Craig Glazer, Chenchao Lu (PJM); Paul M. Flynn, Ryan J. Collins, Elizabeth P. Trinkle (Wright & Talisman), Re: PJM Interconnection L.L.C., Docket No. ER21-2582-000, Revisions to Application of Minimum Offer Price Rule July30, 2021 with attachments A–G.

- Capacity markets with sloping demand curves cannot simultaneously produce low prices and poor resource adequacy as MOPR-Ex advocates have claimed;
- Merchant generation investors operate in a market and regulatory context that has always required them to face uncertainties associated with a wide range of energy and environmental regulations at the federal, state, and local levels. These policies and associated economic subsidies have influenced the resource mix (some in favor of incumbent fossil resources and others in favor of clean energy resources). Merchant investors should never have expected to be indemnified against risks associated with these policies (nor should they be required to return revenues to customers when policy changes favor their own investments); and
- Broad application of MOPR to policy resources has amplified (not mitigated) the regulatory risks affecting capacity investments.

Overall, MOPR-Ex advocates aim to solve a problem that doesn't exist. Their primary concern appears to be that as incumbent capacity resource owners, they no longer expect to earn a satisfactory return on their investments. While certainly a concern for incumbents, low capacity prices are not a problem from a societal or market design perspective. Low prices are simply a reflection of market conditions indicating ample capacity supply; they appropriately signal that no new capacity is needed and that high-cost existing resources should retire.

The MOPR should be maintained only for its narrow original purpose of addressing manipulative price suppression, not applied to state policy resources. That will enable the capacity market to continue offering competitive benefits by producing accurate price signals that align with market fundamentals and attract investment when needed.

Applying MOPR to Policy Resources Imposes Uneconomic Excess Costs on Customers and on Society as a Whole

The MOPR requires policy resources to offer into the capacity market at a higher price than they otherwise would, which can prevent these policy resources from clearing the market even if they will be built anyway and contribute to resource adequacy. Excluding them causes the capacity auction to perceive a supply "gap" that it will seek to fill by clearing other, higher-cost capacity resources while setting a higher clearing price. MOPR-Ex therefore causes the auction to retain more existing capacity resources (such as coal plants that would otherwise retire) and/or attract new investments (such as new gas combined cycle plants that would not otherwise be built). The total amount of capacity available and operating would exceed the amount needed to meet the reliability objectives that the capacity market was designed to meet.

To evaluate the impacts of applying MOPR to policy resources, we conducted a simulation analysis of the PJM capacity market in scenarios with: (a) the status quo of MOPR-Ex as applied to policy resources, and (b) no MOPR applied to policy resources such as under PJM's focused proposal.[12] As summarized in Figure 1, we estimate that if MOPR-Ex is maintained in its present form, by 2030 it would:

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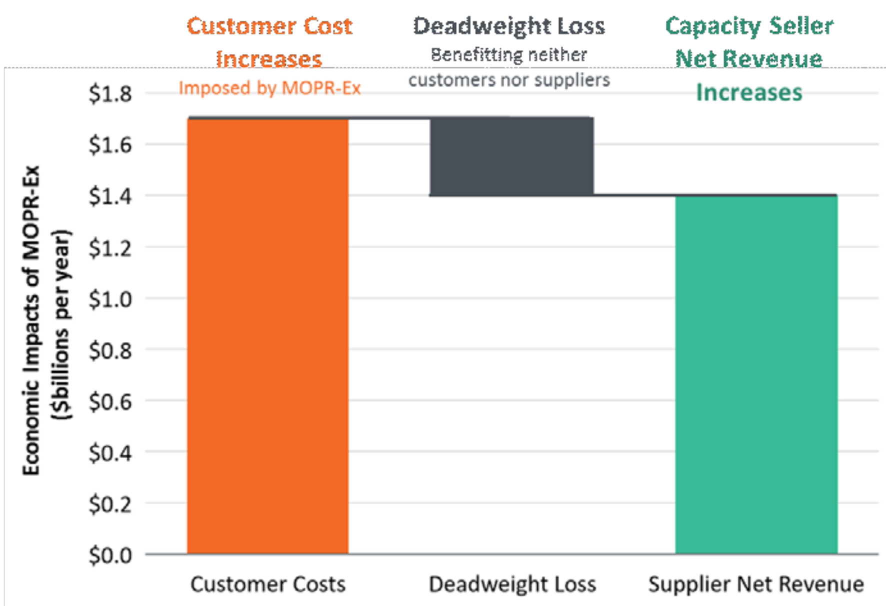
[12] We conducted this analysis on behalf of the New Jersey Board of Public Utilities (BPU) as an input to their assessment of alternative resource adequacy structures. See New Jersey Board of Public Utilities, Alternative Resource Adequacy Structures for New Jersey Staff Report on the Investigation of Resource Adequacy Alternatives, Docket #EO20030203, June 2021. The full report is included as Attachment A to this testimony.

- Prevent the capacity market from clearing approximately 6,800 MW of unforced capacity (UCAP) from state policy resources;
- Impose approximately $1.7 billion per year in excess costs on consumers in two ways: first, by causing them to pay higher capacity prices than is economically efficient (a cost that is borne by all customers, even those in states that have not supported any policy resources); and, second, by requiring customers in states with the affected policy resources to "pay twice" for capacity (once for policy resources that cannot clear, and a second time for duplicate capacity that does clear);
- Of the $1.7 billion in excess payments to capacity sellers, approximately $0.3 billion would be wastefully deployed toward the uneconomic retention of excess capacity resources beyond what is needed for reliability. This $0.3 billion in excess spending is economic deadweight loss that benefits neither customers nor suppliers; and
- The remainder of the excess capacity payments are a wealth transfer of approximately $1.4 billion per year from customers (who must pay a higher capacity price) to suppliers of capacity that would be there with or without MOPR (and who will earn the higher capacity price).

PJM's proposal for a focused MOPR would eliminate these adverse impacts caused by the expansive MOPR. This will restore the capacity market to its role in producing accurate prices and guiding market participants to pursue cost-effective entry and exit decisions.

FIGURE 1: IMPACTS ON PJM CUSTOMER COSTS AND CAPACITY SELLERS' NET REVENUES FROM IMPOSING MOPR ON POLICY RESOURCES BY 2030



Sources and Notes: See comprehensive modeling approach description in Attachment A, Section II.C, Appendix A, and Figure 20.

PJM's expert witness, Professor Peter Cramton, provides an assessment of the impacts of MOPR-Ex that largely aligns with our own. Professor Cramton similarly finds that MOPR-Ex induces systematic over-procurement, is not needed for reliability, and imposes excess costs on customers.[13] Our analysis

[13] See Affidavit of Peter Cramton on behalf of PJM Interconnection, L.L.C, p. 12, Attachment C of Letter to Kimberly D. Bose from Craig Glazer, Chenchao Lu (PJM); Paul M. Flynn, Ryan J. Collins, Elizabeth P. Trinkle (Wright &

does differ from Professor Cramton's in some respects, due to differences in modeling frameworks and assumptions. The primary difference is that we anticipate a larger volume of resources would be affected by MOPR than is assumed in Professor Cramton's analysis. We developed our bottom-up, state-by-state estimate of the volume of policy resources that would be affected by MOPR after projecting the outlook of new resources needed to fulfill these policies over time. Professor Cramton has adopted a smaller number, an input assumption provided by PJM at the time. We believe that an updated estimate would be closer to ours, considering the larger volume of resources that PJM has projected in its more recent planning outlooks.[14] Due to this difference, we have estimated larger impacts on customer cost and larger excess procurement volumes from continuing MOPR-Ex.

Another difference is that we estimate approximately \$26/MW-day and \$25/MW-day increases in capacity price could be caused by MOPR-Ex in both 2025 and 2030 respectively. Our estimate of these MOPR-Ex price impacts are relatively similar in both years because there is a higher volume of capacity supply excluded by MOPR in 2030, but this is offset by the moderating effect of long-term entry and exit. Our approach utilizes an upward-sloping supply curve based on actual PJM capacity auction offer data (for 2025) and a more moderate but still upward-sloping longer-term supply curve (for 2030). Professor Cramton's model focuses on an even longer multi-decade timeframe over which the capacity supply curve becomes even more moderated (close to flat in the very long term relevant for his study), which explains his finding that prices are similar with or without MOPR-Ex.

The two approaches are complementary: our analysis provides the most robust estimate of near- and medium- term magnitudes of MOPR-Ex price, cost, and quantity impacts; Professor Cramton's modeling provides an assessment of the long-run outcomes that should be expected (though we expect that the magnitude of impacts he estimates would be larger with an updated estimate of the quantity of affected resources). We use alternative and complementary approaches to arrive at the same conclusions that MOPR-Ex will induce excess capacity to be developed, impose excess costs on customers, and is not needed for reliability.

Competitive Markets Must Acknowledge Policy Goals In Order to Enable the Greatest Benefits from Trade

Far from protecting the capacity market, applying the MOPR to policy resources will erode and eventually eliminate the benefits of the competitive capacity market. With MOPR-Ex the disconnect between market fundamentals and clearing prices will grow as greater quantities of policy-supported resources come online over the coming years. The consequential growth in excess customer costs, societal costs, and wealth transfers to incumbent capacity suppliers will rapidly become unsustainable from a policy and economic perspective.

Talisman), Re: PJM Interconnection L.L.C., Docket No. ER21-2582-000 Revisions to Application of Minimum Offer Price Rule July30, 2021 with attachments A–G and the more detailed paper describing the modeling approach: Peter Cramton, Emmanuele Bobbio, David Malec, and Pacharasut Sujarittanonta, *Electricity Markets in Transition: A multi-decade micro-model of entry and exit in advanced wholesale markets*, July 2021.

[14] For example, in a recent planning outlook, PJM has projected approximately 82,961 ICAP MW of offshore wind, onshore wind, solar, and storage will be needed to meet policy targets by 2035 (a projection that is similar to our own). However, to compare this number meaningfully to our own estimate of resources affected by MOPR-Ex, PJM's projected volume of policy resources would need to be converted to a UCAP basis and deduct resources not subject to MOPR such as existing resources and distributed solar as we have done. See p. 21 of "Offshore Transmission Study Group Phase 1 Results," August 10, 2021.

The solution to this problem is simple: eliminate the application of MOPR to policy resources and allow prices to reflect the intersection of supply with demand; and let every resource count for its reliability contribution, so the market will attract investment when needed and not when not needed. PJM's proposal will have this effect.

The MOPR is a blunt instrument designed only for its narrow original purpose of addressing manipulative price suppression. MOPR-Ex cannot harmonize incentives across state policies and efficient wholesale markets. MOPR-Ex would not improve PJM's ability to operate reliably in a system that is increasingly dominated by clean and distributed resources. And MOPR-Ex would not preserve the merchant investment model. These are very real challenges that must be addressed through enhancements to wholesale markets and state policies alike. But MOPR cannot serve these ends because it was never designed to do so.

The RTO, stakeholders, and state policymakers in PJM and other market regions are already considering a range of opportunities to better align wholesale markets with states' environmental policies, including enhanced carbon pricing, enhanced energy and ancillary service market designs, improved reliability accounting, and regional clean attribute markets.[15] These reforms may take some time to fully materialize but will ultimately support the evolution toward a fit-for-purpose wholesale market that acknowledges the reality of state policies. These state policies will be among the many financial and non-financial influences affecting the type, quantity, and prices at which supply and demand may arrive in the wholesale market, as well as the reliability products that will be needed to manage the resulting system. From there, the benefits of an efficient market derive from providing pricing and clearing structures through which public and private actors alike can inform their decisions and best serve their own interests. An efficient market will not "pass judgement" on whether those interests are acceptable or limit access for those deemed unworthy. The most efficient wholesale market is the one that can match supply and demand in ways that maximize the benefits of trade, including by introducing new markets when there are substantial opportunities for mutually beneficial transactions that are net yet facilitated via wholesale markets.

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[15] See for example, PJM, Capacity Market Reform: Phase 2, August 12, 2021.

A. Background

A.1. The PJM Capacity Market

The PJM capacity market, the Reliability Pricing Model (RPM), is a centralized competitive platform within which the market operator procures the quantity of resources needed to meet regional resource adequacy or reliability needs. PJM uses an administrative demand curve to procure at least the quantity of capacity that it estimates will be needed to ensure that bulk system supply shortages are infrequent, occurring no more often than once in ten years in expectations (the “1-in-10” reliability standard). Import-constrained locations such as the Mid-Atlantic Area Council (MAAC) are represented by separate demand curves establishing a minimum quantity of capacity that must be located in that subregion.

Capacity sellers offer their resources into the market at the minimum price they are willing to accept to come online or stay in the market. For any given resource, the minimum price they are willing to accept is driven by a number of factors, including primarily: costs associated with bringing new supply into the market or maintaining an existing facility that needs re-investment; minus any anticipated net revenues that could be earned from energy markets, ancillary service markets, or other revenue sources (such as sales of renewable energy credits (RECs), steam, or gypsum). Sellers also adjust their capacity offer price based on any bilateral sales agreements for capacity, any co-products they may produce, and their long-term view of future energy and capacity prices. Sellers that are able to pre-sell most of their capacity or energy through bilateral contracts would typically offer into RPM at a zero price, as would most sellers that have already come online or require minimal going-forward capital investments.

Capacity prices for all resources are set at the intersection of sellers’ capacity market supply offers and the administrative demand curve in each location and system-wide. Under this framework, the capacity market produces prices consistent with supply-demand conditions. The market produces low prices when the region has more than enough supply to meet resource adequacy needs; it produces high prices when capacity supply is scarce. Since PJM’s capacity market was implemented for the 2007/08 planning year, it has produced competitive prices signaling the relative need for capacity (or lack thereof); attracted new entry from generation, imports, and demand response when needed; and allowed for the orderly retirement or net exports of higher-cost resources when supply was long.[16]

A.2. MOPR and its Expansion in PJM

One of the design elements of the capacity market is a comprehensive framework for mitigating the potential for both supply-side and demand-side market power abuses, consisting of several interrelated design elements. Chiefly, the monitoring and mitigation framework includes: (a) *sell-side mitigation* provisions that impose capacity price offer caps and must-offer requirements that are intended to limit the ability of large net sellers from manipulative economic or physical withholding that could inflate market prices; (b) *buy-side mitigation* provisions that impose offer floors to prevent manipulative suppression of market prices (though the application of offer floors was expanded beyond this purpose in MOPR-Ex, as discussed below); and (c) *independent monitoring and mitigation* activities to regularly review market efficiency and competitiveness. Together, these comprehensive monitoring

[16] See, for example, Monitoring Analytics, 2020 State of the Market Report for PJM: Section 5 – Capacity Market, March 11, 2021.

and mitigation rules support price formation that market participants can anticipate will largely reflect economic fundamentals and supply-demand conditions, without being driven by the private interests of a player with large buy- or sell-side market share.

A robust monitoring and mitigation framework must be crafted in a targeted fashion in order to minimize the risk of applying buy or sell-side mitigation mechanisms to entities that do not have the incentive or ability to exercise market power. These entities cannot privately benefit from exercising market power, so mitigating their chosen offer prices serves no purpose to the broader market. If an offer price cap (or floor) is imposed on such a competitive offer price, this inflates the risk that a seller may incur unrecovered costs, introduces deviations away from the competitive price level, and induces economic inefficiencies. Though no market should guarantee that sellers are always able to recover their costs, it should guarantee that sellers can accurately reflect their costs in their offer prices so that they have a reasonable opportunity to recover costs through competitively-set prices.

The purpose of the original targeted MOPR in the context of the overall market monitoring and mitigation framework was to prevent manipulative price suppression. The rules were intended to prevent entities with a large net buyer position from exercising buy-side market power. Without such a rule, a large net buyer could be in a position to game the capacity markets by bringing a small quantity of incremental capacity supply into the market, offering the supply at a zero price, and producing a low capacity price. In some cases, a large buyer supporting new entry would not be a problem. For example, if the incremental supply is relatively low cost and thus a better deal than purchasing generalized capacity from the market. However, the purchase can be viewed as manipulative price suppression if the incremental supply is very high cost, higher than the but-for capacity price that would otherwise have materialized. In that circumstance, the buyer would develop uneconomic supply (taking a financial loss on a small quantity of high-cost capacity supply) in order to achieve a lower capacity price (thus benefitting the much larger net buy position). This behavior is, by definition, manipulative because the uneconomic incremental supply resource is not a rational resource to develop when viewed in isolation. The incremental supply is pursued only for the purpose of suppressing market prices below the competitive levels that would prevail from individually rational entry and exit.

To prevent this manipulative price suppression, a targeted MOPR would restate the offer price from zero to a higher level based on estimated net resource costs. The higher MOPR price prevents this scheme from producing price suppression and makes it less likely that the resource in question would clear the capacity market. When applied to large net buyers and their supported resources, the targeted MOPR can privatize the cost of any potentially uneconomic investments, while holding other parties in the market harmless. More importantly, the existence of the rule is intended to disincentivize the manipulative behavior and associated economic waste from taking place at all. Over the years, PJM's MOPR provisions have been updated several times, but have, for the most part, been updated so as to align with the original purpose of preventing manipulative price suppression.

With the Federal Energy Regulatory Commission's (FERC's) December 2019 Order and PJM's subsequent compliance filings, the current Expanded MOPR (MOPR-Ex) is now more broadly applied to new and existing resources that earn state policy payments.[17] The large majority of these resources in PJM and other regions are awarded policy payments in recognition of their contribution toward achieving states' environmental policies, though many of these resources also advance economic, employment, or other policy objectives as well. MOPR-Ex imposes an offer price floor on a wide array of state-supported policy resources including: (a) new renewable resources developed to meet state

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[17] 169 FERC ¶ 61,239.

environmental targets and renewable portfolio standards (RPS); (b) new demand response, energy efficiency, storage, and distributed energy resources developed under utility or state programs that would otherwise participate in the supply side of the capacity market; (c) nuclear power plants earning zero emission credit (ZEC) or other state policy payments; and (d) all new (and many existing) capacity resources that states may wish to support in service of other environmental, economic, employment, health, safety, technology development, equity, education/training, or other state policy goals.[18] Overall these changes have substantially expanded the scope of capacity resources affected by MOPR such that it no longer has any relationship to the original purpose of mitigating the exercise of buy-side market power.

The mechanics of MOPR-Ex as applied to policy resources are illustrated in Figure 2. The left panel illustrates clearing outcomes if all capacity resources are allowed to offer at their preferred offer price. Many policy resources will offer at a zero price. For example, renewable resources earn the (large) majority of their revenues through energy market and REC payments reflecting their environmental value; a smaller share of their total revenues are earned via the capacity market. Thus, a renewable developer will often make a decision to build based primarily on expected and contracted energy plus REC revenues. Such a resource would be developed and online regardless of capacity price and so would typically offer at zero in the capacity market to ensure they earn capacity revenues. Fossil plants and other capacity resources use a similar logic when developing their capacity offer prices. A rational seller without market power would offer at the minimum capacity price needed to earn a return on going-forward investments. Immediately before a power plant is developed or immediately prior to a major retrofit decision, the owner is likely to offer into the capacity market at a medium-to-high price consistent with what is needed to justify a major investment. Once the investment is made, however, power plants tend to have low or zero net going forward costs, will continue to operate regardless of a single year's capacity price, and so offer at low or zero prices in the capacity market. Together, the aggregation of all offers from capacity resources makes up the market supply curve. Clearing prices are set at the intersection of supply and demand.

When MOPR-Ex is applied to a policy resource, its offer price is increased from zero to a higher level for the purposes of auction clearing. As illustrated in the right panel of Figure 2, the higher MOPR-based price will re-order the capacity market offer supply curve, make it less likely for the policy resource to clear the market, and cause higher clearing prices.

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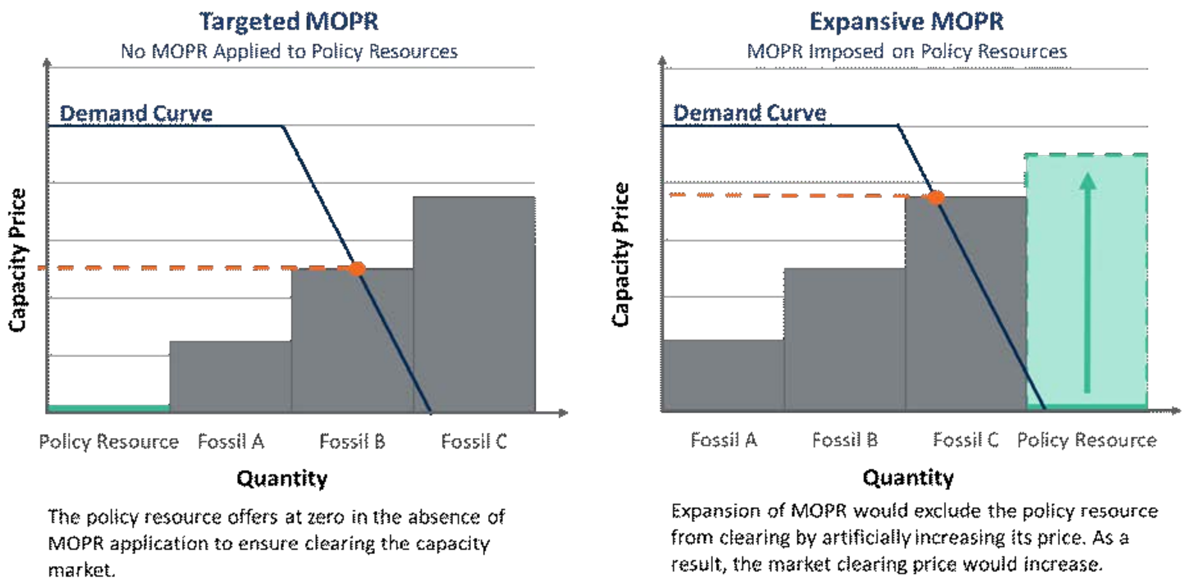
[18] Specifically, MOPR-Ex applies to resources earning revenue from actionable state policy support, including extensive rules designating which types of policies are considered "actionable". Exceptions to MOPR-Ex are made for some (but not all) existing capacity resources. PJM, Manual 18: PJM Capacity Market, August 1, 2021; and PJM, Open Access Transmission Tariff, Attachment DD Section 5.14(h-1), August 1, 2021.

FIGURE 2: EXPANSION OF MOPR INCREASES THE CAPACITY CLEARING PRICE



When applied to policy resources, the mechanics of the MOPR are identical as compared to the application in the context of manipulative price suppression. However, the economic purpose and impact are entirely different. Unlike in the context of manipulative price suppression, MOPR-Ex, when applied to policy resources, is not intended to prevent the investments from taking place. The policy investments will proceed regardless of MOPR because they are developed as a means to advance policy objectives such as environmental or economic goals. Thus the exclusion of these resources from clearing the market will not prevent such investments from taking place. As a result, the total quantity of installed capacity is all resources that have cleared the capacity auction (Fossil A-C) *plus* the Policy Resource that did not clear. This total quantity of capacity exceeds what is needed to meet reliability needs as represented by the sloping demand curve, causing excess investment and excess societal cost.

Another difference between the contexts of manipulative price suppression and policy resources is the scope and scale of the affected resources. In the context of manipulative price suppression, the typical behavior would be that the buyer would endure a small economic loss from developing a small quantity of uneconomic capacity resources, with that small loss more than offset by the gains to the much larger buy-side position. The scope of a targeted MOPR therefore tends to cover a small volume of supply that could be excluded from auction clearing (and likely no resources would even be subject to MOPR given that the mere existence of the targeted MOPR would be likely to prevent any would-be schemers from attempting to exercise buy-side market power).

In the context of policy resources, there is no expectation that the quantities of excluded resources will remain small. In fact, given the mandated climate and environmental policies of the majority of PJM states, the volume of policy resources across the region should be expected to become the majority of the regional marketplace as each state proceeds toward their respective policy goals. Policy-supported resources will need to be sufficient to fulfill ambitious goals, including Washington DC at 100% renewable by 2032, Virginia at 100% renewable by 2045/2050, New Jersey at 100% economy-wide clean energy by 2050, Delaware at 40% renewable by 2035, Maryland at 50% renewable by 2030, and

Illinois considering 100% clean energy as early as 2030.[19] Across the PJM footprint, 92% of customer demand is within states that have adopted renewable portfolio standard (RPS) or other clean energy requirements whose resources could be excluded by MOPR-Ex.[20]

B. PJM's Focused MOPR Proposal will Eliminate the Economic Inefficiencies Caused by the Current Expansive MOPR

PJM's filing in this docket proposes to replace MOPR-Ex with a much more focused MOPR.[21] The mechanics of MOPR when it is applied will be the same as described above. However, the focused MOPR will apply only under narrower circumstances:

- The focused MOPR can only apply to *generation resources*, not to demand response or energy efficiency.
- For non-policy resources, the focused MOPR can apply only in circumstances when the resource has a documented *relationship with a large net buyer that has both the incentive and ability to benefit from manipulative price suppression*. This application is further clarified to ensure that it will not apply to common and accepted business activities including merchant generation investments, competitive procurements open to both new and existing resources, and the self-supply business model of regulated utilities and many public power entities.
- For policy resources, the focused MOPR can only apply to *resources earning "Conditioned State Support,"* whereby they would earn the policy payments only subject to conditions placed on their capacity market offer price and clearing status. Conditioned State Support is furthered narrowed to explicitly exclude the vast majority of state policy support in common use across the PJM region including all existing state policies already in place, as well as future environmental policies, tax incentives, default service auctions, fuel incentives, and state-administered federal policies.

Every one of the changes proposed by PJM will increase the economic efficiency of the PJM capacity market; in its totality the new focused MOPR will eliminate most or all of the inefficiencies caused by the current MOPR-Ex. The central and fundamental improvement is that the proposed MOPR will apply only narrowly.

As applied to non-policy resources, the new MOPR will be restored to its original intent; it will aim to prevent and mitigate market power abuses that could be pursued by large net buyers. In this respect, the PJM's proposal for a focused MOPR is a marked improvement upon all prior versions because it includes a mechanism for PJM and its Independent Market Monitor (IMM) to assess the incentive and

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[19] *See* PJM-EIS, "Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States," and "What is the Clean Energy Jobs Act," Illinois Citizens Utility Board. For an indication of the large scale of policy resources that PJM anticipates will be needed, see PJM Interconnection, "Offshore Transmission Study Group Phase 1 Results" August 10, 2021.

[20] Eleven of the 14 PJM states and the District of Columbia have RPS requirements; Kentucky, Tennessee, and West Virginia do not. Calculated from Monitoring Analytics, Data, Percentage of PJM Load by State, 2021

[21] Letter to Kimberly D. Bose from Craig Glazer, Chenchao Lu (PJM); Paul M. Flynn, Ryan J. Collins, Elizabeth P. Trinkle (Wright & Talisman), Re: PJM Interconnection L.L.C., Docket No. ER21-2582-000 Revisions to Application of Minimum Offer Price Rule July30, 2021 with attachments A–G.

ability to exercise buy-side market power, and makes plain that non-manipulative business activities will not be subject to the MOPR.

As applied to policy resources, the proposed rule is a vast improvement because it removes the application of MOPR from policy resources for most or all practical purposes. As we discuss at length throughout this testimony, the broad application of MOPR-Ex to large numbers of policy resources across the PJM footprint is based on flawed economic logic, would induce large inefficiencies, impose excess customer costs, and would discourage states from continuing to participate in the capacity market. The PJM proposal will eliminate these problems for all practical purposes.

C. The Application of MOPR to Policy Resources is Based on Flawed Economic Reasoning

In its filing, PJM explains why the current MOPR-Ex is unnecessary and will substantially erode the efficacy and efficiency of its capacity market. We agree with PJM's analysis of these flaws.

However, PJM's filing has not yet provided a complete analysis of each of the arguments and concerns that the Commission previously considered in approving the expansion of MOPR to policy resources in December 2019.[22] The stated concerns were as follows. States across the PJM region are attracting large quantities of new resources to meet clean energy and other policy goals, through a variety of programs and contract solicitations that MOPR-Ex advocates consider to be "subsidies."[23] Because these activities could reduce near-term capacity market prices and/or displace "non-subsidized" resources, MOPR-Ex advocates argued that it was necessary to "protect" wholesale capacity markets from the price-suppressive impacts of state policies. They argued that without intervention, market prices would be inappropriately low, merchant capacity suppliers would not earn adequate returns on investment, thus discouraging new capacity from entering the market and threatening future reliability. Their proposed remedy was to impose MOPR on policy resources to restore capacity prices to the "correct" level, *i.e.*, the price that would have prevailed in the absence of the state policies.

The rationale for applying MOPR to policy resources was based on incomplete and flawed economic logic. A corrected economic analysis reveals a simpler truth: that the "correct" capacity price is the one that accurately reflects underlying fundamentals of supply and demand. This is the accurate price that should signal when and where capacity investments are needed (and when high-cost resources can retire). The logical conclusion under this corrected economic analysis is that MOPR should be eliminated from application to policy resources so that capacity prices can be utilized to rationalize supply with demand.

C.1. State Policies Address Market Failures Such as Environmental Externalities

States across the PJM footprint have many reasons for supporting resources. However, by far the most common reason that PJM states support policy resources is to address the environmental and public

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22 163 FERC ¶ 61,236 and 169 FERC ¶ 61,239.

23 We do not subscribe to the view that such state programs and/or solicitations should be considered "subsidies" in the traditional sense, nor that subsidies are inappropriate or inherently problematic if they are pursued in light of policy goals. Instead, we see the introduction of clean energy policies as generally providing compensation for environmental externalities not otherwise provided for by the market itself.

health impacts caused by emissions from fossil fuel plants.[24] Translated to economic terms, these environmental and health impacts are "negative externalities" that are not automatically incorporated into market prices. The outcome of market forces alone is to produce inefficient, excess quantities of such externalities, unless governments take corrective action.

A negative externality is a negative side effect of an economic activity that adversely affects a party not involved in the transaction. The adversely affected third party has no influence over whether the transaction takes place, but is nevertheless harmed. Environmental externalities such as those caused by greenhouse gas and air quality emissions from fossil power plants are the classic textbook example of externalities.[25] Once emitted into the air, greenhouse gases cause a number of adverse effects on residents, businesses, and the environment across PJM, nationally, and globally in the present day and will continue to do so for hundreds of years in the future.[26] Other pollutants such as NO_X, SO_X, and particulates cause more immediate health impacts such as asthma and early death.[27] Absent policies to address these externalities, neither the purchaser of the power (PJM in this case) nor the producer of the emissions (the power plant owner) pays the full cost associated with these negative externalities.[28] Such unpriced or underpriced externalities will tend to be produced at a quantity that exceeds the economically efficient level from a societal perspective. The consequence of ignoring these environmental externalities is that market pricing alone would drive resource investments and operations toward an inefficiently large quantity of fossil fuel-fired power plants, imposing inefficiently large externality costs.

Externalities are by definition not "market forces," but rather market failures. Under their existence markets fail to allocate resources efficiently and the current market price would not be the "correct" one. As a general matter, public policies can address externalities and market failures in one of two ways: one is *command-and-control* policies that regulate behavior directly; the other is to develop market-based policies that align private incentives with social efficiency.[29]

Environmental externalities can be incorporated into electricity markets through policy mechanisms, whether through emissions pricing mechanisms (*e.g.,* carbon pricing) that charge emitters and indirectly reward non-emitters and/or through clean energy attribute payments that reward non-emitters directly. Carbon pricing can take many forms, from a tax or charge approach that sets a price per ton

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24 Even though environmental goals are the most prominent and common policy goals amongst PJM states, most state policies are designed at least in part to consider a range of other objectives as well, such as affordability, equity, local economic effects, and employment.

25 N. Gregory Mankiw, *Principles of Microeconomics*, 5th ed. Mason, (OH: South-Western Cengage Learning, 2009), p. 204.

26 United States Environmental Protection Agency, "Climate Change Indicators: Greenhouse Gases," accessed on November 16, 2020.

27 Michael Guarnieri, John R Balmes, "Outdoor Pollution and Asthma," *The Lancet* 383 (9928): 1581–1592. doi:10.1016/s0140-6736(14)60617-6 (2014).

28 The Regional Greenhouse Gas Initiative (RGGI) has imposed some costs on emitters within a subset of PJM states, but the program does not currently have a mechanism for pricing emissions of imports into RGGI states and has produced prices in the range of $5-8/short ton, which is far the approximate $51/ton social cost of carbon estimated by the United States Government Interagency Working Group on Social Cost of Greenhouse Gases. See Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, February 2021., and RGGI, Inc., Regional Greenhouse Gas Initiative, Allowances, Prices, and Volumes, 2021.

29 N. Gregory Mankiw, *Principles of Microeconomics*, 5th ed. Mason, (OH: South-Western Cengage Learning, 2009), p. 154–210.

emitted; to a cap-and-trade approach that sets a cap on emissions and lets the market determine the price of allowances; to a hybrid, such as the Regional Greenhouse Gas Initiative (RGGI) that is nominally "cap-and-trade" but that includes adjustable caps to serve as price collars. In all of these cases, carbon pricing raises the cost for emitters to produce, making them less competitive and raising market clearing prices for energy; non-emitters earn the higher prices without being charged. Clean energy attribute payments work more directly by paying non-emitters to produce carbon-free energy. Such payments can be provided through long-term contracts, attribute markets, and other policy incentives, as demonstrated through a wide range of ZEC, REC, and other programs in use throughout the PJM footprint. The mechanisms used to support clean energy resources will continue to evolve as states, PJM, and stakeholders continue to assess the most effective and efficient opportunities to support the clean energy transition, as discussed in Section E below.

Many economists (and some pro-MOPR-Ex advocates) argue that a carbon pricing mechanism would be a better way to address these environmental externalities and enable all resources to compete based on market prices for energy (that account for carbon-related externalities), capacity, and ancillary services. We agree with many of the arguments in favor of carbon pricing but caution that electricity sector carbon pricing alone may be an incomplete solution in the context of the wide diversity of state environmental mandates (and lack thereof) across the PJM region.

We too believe that carbon pricing would help support the states' environmental objectives cost-effectively, through resource-neutral competition that accurately signals where and when clean energy production displaces the most carbon emissions, while also appropriately rewarding storage and higher-efficiency gas-fired generation that partially reduce emissions. The ideal is for a carbon pricing regime to apply uniformly and comprehensively in its geographic scope (across state and national borders) and in its coverage of all economic sectors. However, without this comprehensive scope, carbon pricing could induce unintended effects such as leakage or disincentives to electrify heating and transportation demand. Within the PJM Carbon Pricing Senior Task Force, many stakeholders as well as PJM staff have been working to identify solutions such as border adjustments, allocating carbon revenues to customers, and improving coordination with RGGI as opportunities to address these challenges.[30] Implementing such solutions could be technically and politically challenging, but carbon pricing should continue to be pursued, especially at a national and economy-wide level in order to achieve carbon abatement in the most cost-effective fashion.

However carbon pricing should not be presented as the only "legitimate" or "efficient" policy option for reflecting state policy priorities into electricity markets. Even if carbon pricing is pursued, the practical reality is that carbon prices alone may not be set high enough to support sufficient investment to meet mandated clean energy targets in the timeframe required by PJM states' laws. Clean energy attribute payments, competitive clean energy solicitations, and customer-backed contracts for clean energy resources are all alternative approaches that can be pursued for addressing environmental externalities, each with advantages and disadvantages relative to carbon pricing in terms of timing, economic efficiency, risk allocation, and implementation feasibility. Further, different communities, customers, and state governments across the region will place different values on their deemed cost of carbon emissions and so will not be able to establish a single market-wide carbon price that reflects all of the region's policy requirements. Overall, we anticipate that a combination of carbon pricing, clean energy attribute payments, and other policy structures will be needed to meet states' respective mandates.

30 PJM, Committees and Groups, Carbon Pricing Senior Task Force.

Unless and until a single policy approach to addressing externalities would be agreed upon across the PJM region, the marketplace can acknowledge that states, communities, and customers will use a range of market-based and non-market-based mechanisms to pursue their legitimate interest in addressing environmental externalities. As the demand side of wholesale electricity markets, customers and their elected representatives have the proper role of establishing how much they are willing to pay to address environmental externalities and what combination of contracts and policies they wish to use to express that value. An efficient marketplace should aim to assist states and customers by providing options for achieving their environmental goals at the lowest possible cost.

C.2. The "Correct" Capacity Price Is the One that Aligns Supply with Demand (Not the Price that Would Prevail in the Absence of State Policies)

The efficient outcome in a market, or set of interconnected markets, is that which maximizes social welfare: the sum of consumer and producer surplus. Absent environmental externalities and with market participants acting competitively, this outcome would result at the price where the marginal cost of supply (to producers) is equal to the marginal value of additional consumption (to consumers). However, when environmental externalities are introduced, the intersection of (private) supply and demand *will not represent the efficient outcome.* This inefficient outcome is the one that MOPR-Ex would seek to re-establish. Instead, the correct capacity price is that which aligns supply and demand, given other policies and/or markets that policymakers have identified as necessary to address externalities and other policy priorities.

Compensating capacity resources for their environmental and other policy value lowers their net cost of providing capacity (regardless of whether that compensation is achieved through carbon pricing, clean energy payments, or some other mechanism). Clean energy resources correctly appear more competitive as capacity providers, just like resources with high energy and ancillary services value, and they should be allowed to clear the capacity market and be recognized for the resource adequacy value they contribute to the system.

If the capacity market consequently produces low prices, this is correctly signaling an oversupply of capacity, that no more investments are needed for resource adequacy, and that the least valuable resources should retire. Reliability will not be threatened by replacing traditional power plants with non-emitting resources, as clean resources will be assigned capacity ratings reflecting only the reliability value they actually provide. In fact, under PJM's new effective load carrying capability (ELCC) approach recently approved by the FERC, capacity accreditation for intermittent and storage resources is already a fraction of their nameplate capacity and will be continuously updated to reflect their capacity value market share increases.[31] Thus, as the clean energy transition proceeds it will take greater quantities of wind, solar, and battery supplies to replace a single retiring gas or coal plant. Through this continuously-adjusted displacement rate, reliability will be maintained. PJM's methods for accurately assessing capacity needs and resources' reliability contributions will need to continue to be refined throughout the upcoming fleet transition (just as they have been continuously refined since the advent of the RPM).[32] The combination of accurate, ELCC-based capacity ratings and a graduated sloping demand curve will allow for an orderly pace of retirements that largely proceeds on the same

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31 See, for example, PJM's preliminary analysis illustrating how different intermittent and storage resources' capacity ratings may change over the coming decade. See PJM Interconnection, Preliminary ELCC Results, February 18, 2021.

32 PJM's board and management have identified enhancements to reliability accounting on the supply and demand side of the capacity market as a priority focus area over the coming years. See PJM Interconnection, "Capacity Market Reform: Phase 2," August 12, 2021.

pace that new resources are developed. For the same reasons, the market (absent any MOPR application to policy resources) can provide the right price signals and result in efficient outcomes with the least-cost set of economic retirements, entry, and retention of resources needed to maintain resource adequacy. This all works if every resource is accurately counted and compensated according to its contribution to resource adequacy (as they will be if PJM's focused MOPR proposal is implemented).

Yet, forcing policy resource offers upward via MOPR can prevent them from clearing the market. It results in an artificially high capacity clearing price and induces inefficient behaviors and uneconomic incentives: it can retain costly existing supply that would otherwise retire, attract costly new supply that is not needed, and disincentivize customers from utilizing more electricity given inflated prices that signal a false scarcity of capacity supply. Thus, the application of MOPR to policy resources causes the capacity market to depart from supply-demand fundamentals.

The inefficiency of the outcome is especially apparent considering that policy resources will be developed and operated regardless of whether or not they clear the capacity market. Thus the MOPR distorts the capacity market by requiring the mandatory procurement of additional capacity on behalf of customers, beyond what is needed to meet the reliability standard. Under MOPR-Ex, the capacity market simulates a fictional reality as if the policy resources that help meet demand did not exist. Under that fictional scenario, the reliability value of the policy resource in question is ignored, the capacity market price reflects a fictional "need" for capacity, causing consumers to pay real money for real capacity resources to fill that fictional need. This scenario is inefficient when it excludes even one policy resource from clearing the market. It becomes entirely nonsensical when applied to states with high 50−100% clean electricity mandates. Many (and for some states, literally all) policy-supported resources that physically supply resource adequacy could be excluded from being counted in the capacity market, while the capacity market would remain a multi-billion-dollar-per-year parallel "shadow market" that exists primarily as a means for customers to make duplicative payments to resources that are not needed for resource adequacy.

Thus the MOPR-Ex offers a costly solution to a non-problem. The grievance from the standpoint of incumbent fossil generators is that they cannot compete and win against the clean resources that states and consumers prefer. As a consequence, fossil generation owners will earn lower revenues than they would in a world where emissions do not matter or where state policies favored their resources. Failing to earn a return on investment may be problematic for the owners of such assets, but this is not a problem that the wholesale markets can or should fix. The fix occurs when generators shift their investment portfolios toward the types of electricity resources that customers and states want to buy.

Capacity prices will be lower under PJM's focused MOPR approach than they would be if MOPR-Ex were maintained. These lower capacity prices are not a problem from a market design, reliability, or economic perspective. Low prices would be produced only when supply is long, new entry is not needed, and retirements can be accommodated. Applying MOPR to policy resources creates a fundamental disconnect between market pricing outcomes that deviate from the underlying fundamentals of supply (including that associated with state policy resources) and demand (as expressed through resource adequacy requirements).

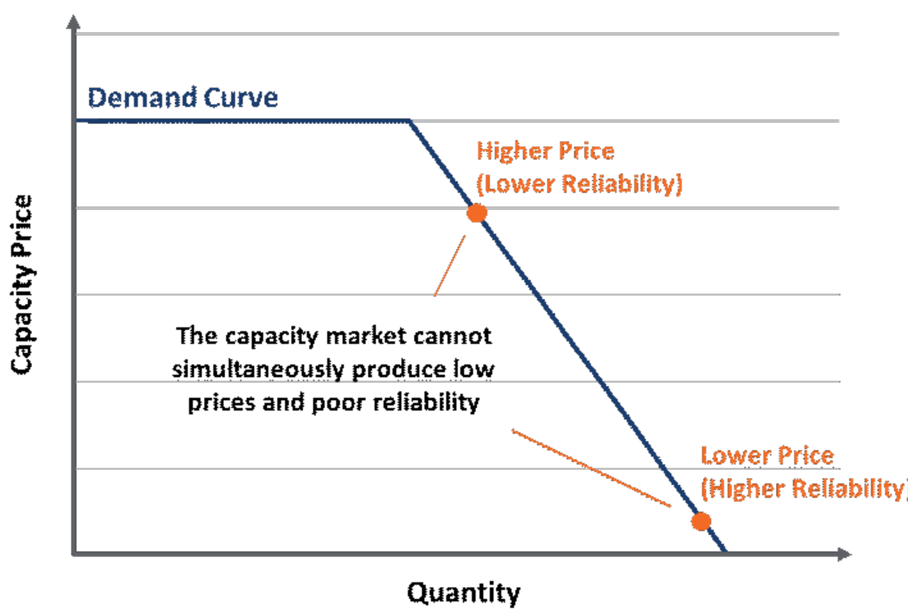
C.3. Capacity Markets with Sloping Demand Curves Cannot Simultaneously Produce Low Prices and Poor Resource Adequacy

MOPR-Ex advocates have expressed a misguided concern that the low prices that may prevail due to growth in policy resources will threaten reliability by discouraging investment.

As shown in Figure 3, this concern is illogical in the context of a capacity market with a downward-sloping demand curve that reflects the required reserve margin and the incremental value of additional supply beyond that reserve margin. By its nature, the downward sloping demand curve simply cannot produce market outcomes with low prices and low reliability at the same time. If prices are low due to the entry of policy resources, this means that there is ample supply of capacity on the system. In this long market condition, the low capacity prices signal that high-cost resources should retire and new entry is not needed. If the supply-demand balance tightens, prices will rise and signal the need to attract and retain scarce capacity. Thus, the concern that low prices will produce low reliability is unfounded (and a mathematical impossibility).

This is not to say that reliability is not a concern in the clean energy transition. As noted above, intermittent resources whose unavailability may be correlated across the fleet (*e.g.,* low wind days, or low solar insolation periods such as nighttime) provide less and less incremental resource adequacy value as their penetration increases. Capacity markets must recognize that fact through resource accreditation that accurately reflects resources' contribution to system reliability. Beyond the context of capacity markets discussed in this testimony, other aspects of the wholesale electricity markets including energy, ancillary service, and transmission planning rules will need to be enhanced to ensure robust pricing and operations in the context of different resource patterns and capabilities throughout clean energy transition. In all cases, across all electricity products, the system will need to be refined to accurately reflect reliability needs, enable all resources to support those needs (subject to their technical capabilities), and use principles of supply and demand to establish efficient pricing to meet those needs.

FIGURE 3: CAPACITY MARKETS WITH DOWNWARD-SLOPING DEMAND CURVES CANNOT SIMULTANEOUSLY PRODUCE LOW PRICES AND POOR RESOURCE ADEQUACY



C.4. Merchant Investors Operate Amidst Wide-Ranging Energy and Environmental Policies from which They Never Should Have Expected to be Indemnified

Some MOPR-Ex advocates express concern that their merchant investments are not earning the return on investment that they anticipated. They assert that "state subsidy issues" are producing prices that are too low to provide a sufficient return on merchant power plant investments.

While poor investment returns are a concern for the affected asset owners, this is not necessarily a concern from a market design perspective. Merchant generation investors operate in a market and regulatory context that has always included environmental regulations from which they should not expect to be indemnified any more than they should be charged when regulations work in their favor. The Mercury and Air Toxic Standard (MATS), other environmental regulations, and general market conditions, for example, contributed to the retirement of some 37,000 MW of installed capacity (ICAP) from aging coal, oil and gas plants over 2012–2020. These retirements created opportunities for approximately 35,000 ICAP MW of new gas-fired power plant investments even though peak demand has remained relatively flat.[33] Natural gas-fired generators also benefit from various tax policies and ratepayer-funded gas transportation infrastructure that have lowered the delivered costs of their fuels.[34] In the future, merchant capacity suppliers may enjoy upward price pressure that may be caused by policy-driven electrification of vehicle and transportation sectors.

The majority of states' policies across the PJM region will not enhance returns to the fossil-fired plants that are major emitters of carbon dioxide. But this should not have surprised generation owners, as states across the PJM region have long discussed and expressed their environmental policies, including the need to limit carbon emissions to address climate change. Investors in new power plants can review the outlook of state RPS mandates as an indicator of the minimum growth in renewable supply that should be expected (while considering that nearly all PJM states have increased their RPS mandates at several points as their programs have proven cost effective and as environmental commitments have strengthened).[35] No responsible investor in any power plant entering the PJM capacity market can have made its investment and been unaware of the downside risks associated with states' environmental policies. Some investors may have miscalculated by underestimating the pace and magnitude of PJM states' environmental policies, but many other investors have had the foresight to adjust their business strategies to align with clean energy transition.

Reviewing recent capacity market outcomes further undermines the claims that policy resources are somehow driving "uncompetitive" low prices or making it impossible for merchant generators to compete. The real reason that capacity prices have been low is precisely because the market has driven competition, with most capacity market entry and exit decisions involving merchant generation resources (not policy resources). Using the last PJM capacity auction results as an example, when the system capacity price cleared at the surprisingly low price of $50/MW-day (compared to the much higher $260/MW-day estimate of the net cost of new entry (Net CONE) that was used to calculate the demand curve).[36] This low price was affected in some part by state policies; for example, 1,785 ICAP MW (about 500 UCAP MW) of new renewable resources cleared the auction.[37] But the much larger driver of low capacity prices was another large increase in the volume of new gas combined-cycle plants that cleared the market at 5,627 ICAP MW (approximately 4,300 UCAP MW).[38] In fact, since

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33 Coal retirement data from PJM, Generation Deactivations. Gas-fired power plant additions from PJM, 2022/2023 RPM Base Residual Auction Results, June 2, 2021.

34 For example, s*ee* Testimony of Doug Koplow on behalf of Sierra Club in Protest on Behalf of Clean Energy Advocates", in FERC Docket No. ER18-1314, May 7, 2018.

35 See DSIRE, Database of State Incentives for Renewables & Efficiency.

36 PJM, 2022/2023 RPM Base Residual Auction Results, June 2, 2021.

37 PJM, 2022/2023 RPM Base Residual Auction Results, June 2, 2021.

38 Both of these numbers are from the PJM auction results report and appear to indicate different levels of resource clearing (given that thermal plants typically have UCAP at 95% of ICAP); one possible reason for the difference could be partial clearing of some resources. ICAP values are precise from Table 8, UCAP is cleared new units from Table 2A after subtracting renewable entry. See PJM, 2022/2023 RPM Base Residual Auction Results, June 2, 2021.

2015/16 planning year, over 35,000 ICAP MW of gas plants have entered the PJM capacity market, demonstrating that the merchant investment model is alive and well.[39] If investors feel that they have earned too little in the capacity market, they can more accurately blame their merchant competitors for the low prices (rather than state policymakers).

Regardless of whether investors anticipate the full extent or particulars of any states' policy mandates, these policies are part of the broader market context in which all PJM capacity resources have chosen to invest. They chose to bear the risks and rewards associated with changing market conditions and regulations, and there is no reason to indemnify them through an expansive MOPR. Doing so distorts the market, as explained above, and imposes unnecessary costs on consumers.

C.5. Expanding MOPR Application to Policy Resources Amplifies (Rather than Mitigates) Regulatory Risks

MOPR-Ex advocates have argued that applying MOPR to policy resources is necessary to mitigate regulatory risk surrounding capacity investments. We acknowledge that capacity investments do face more regulatory risk in a world with environmental policies than one in which policies never change; and that imposition of increasingly-stringent policies will usually disadvantage higher-emitting resources and any other resources not favored by state policies. The application of MOPR-Ex to clean energy policy resources undoes some of that effect, by elevating capacity prices to the level that would prevail absent the policy resources. MOPR-Ex would also cause the market to attract and retain more merchant capacity than with a targeted MOPR. As long as MOPR-Ex is maintained, it will benefit incumbent capacity resources and may even attract more investment in new gas-fired resources (in both cases, securing more capacity than is needed for reliability).

However, elevated prices should not be conflated with less-risky prices. We do not believe the MOPR-Ex reduces regulatory risk or provides an efficient basis for attracting new investment. On the contrary, a market whose price is artificially inflated by a rule as controversial and economically inefficient as MOPR-Ex is unsustainable. Investors will not count on the price premiums produced by such a rule to persist over the long term. They would have to realize that, over time, the pressure to eliminate MOPR-Ex will only increase as mounting quantities of policy resources are excluded from the market and the MOPR-Ex-supported price and capacity deviate further from reflecting actual supply and demand conditions. Customers will ask why they are paying so much to support excess capacity. They will notice that the excess capacity they are supporting is primarily fossil fuel generation that contravenes state clean energy policy goals with wide popular support, and they will demand change. States and utilities will pursue the economic and environmental objectives of their constituents by exiting the capacity auction under the Fixed Resource Requirement (FRR) alternative, rather than continuing to bear these excess costs. For these reasons, capacity markets that fail to accommodate policies that states are committed to pursuing cannot form the basis for a sustainable market design that supports investment.

Capacity markets can better support merchant investment when needed, with lower regulatory risk, if they do not apply MOPR to policy resources. Such a market reflecting actual supply and demand conditions—counting each resource for its contribution to resource adequacy—will send just the right price signals to maintain resource adequacy at least cost. Merchant investors will still face market and regulatory risks, including risks from environmental policies changing in the future. States can mitigate

[39] PJM Interconnection, L.L.C., "2022/2023 RPM Base Residual Auction Results," Table 8.

these risks by setting environmental policies on a long-term stable basis, as many states have already done via multi-decade commitments that will not be fully realized until 2040 or 2050. Investors can then view these policies as part of the fundamentals against which they can plan their business strategies.

C.6. There Is No Economic Justification for Expanding MOPR to Policy Resources (Or Using It for Any Purpose Other than Mitigating the Market Power Abuses)

MOPR is an appropriate mechanism for its original purpose of preventing manipulative price suppression.[40] In that context MOPR has a valid economic rationale: to prevent net-short entities and their representatives from sponsoring uneconomic investments to suppress prices, benefit themselves in the short run (at the expense of other market participants), and induce economic deadweight losses.[41] Applied for that original purpose, MOPR can work together with other elements of a comprehensive monitoring and mitigation framework that assures market participants that market outcomes will be competitive, reflecting supply-demand fundamentals.[42]

This valid economic rationale for MOPR does not apply in the context of state policy resources:

- Policy resources across the PJM footprint are supported as a means to pursue environmental, public health, economic growth, or employment objectives. As long as they are not pursued as a means to profitably suppress capacity prices, they should not be subjected to the MOPR.
- State-supported capacity resources are not uneconomic just because they receive payments beyond what they would earn through wholesale electricity markets alone. In the case of environmental policies, incentives can correct for the market failure to reflect the costs of environmental externalities associated with climate change and public health.
- Applying MOPR to policy resources does not prevent uneconomic behavior (as it does when applied to mitigate manipulative price suppression schemes); rather, it actually *causes* uneconomic behavior by incentivizing the retention of uneconomic, unneeded resources.

States' energy policies will have a number of effects in the electricity sector and broader economy. Capacity markets, like all other markets, can be affected by these policies. The overall outcome of an effective policy to mitigate climate change will be to reduce the greenhouse gas emissions produced and to guide the resource mix away from fossil and toward a mix that meets energy and reliability needs with cleaner resources.

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40 *See:* FERC, Docket No. EL07-39-000, Order Conditionally Approving Proposal at PP 100–P100106, March 7, 2008.

41 This deadweight loss is the cost of the uneconomic resources in excess of the value they provide. The costs of the resources developed in order to suppress prices exceeds the cost of the resources displaced that would otherwise have cleared the market.

42 *See* Affidavit of Dr. Samuel A. Newell on Behalf of the Competitive Markets Coalition: FERC Docket No. ER13-535-000 (supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model).

D. Applying Expanded MOPR to Policy Resources Imposes Uneconomic Excess Costs on Customers and on Society as a Whole

Applying MOPR to policy resources can prevent resources from clearing the capacity market, even though they will continue to operate in the energy market. Forcing policy resources to offer into the capacity market at a higher price will increase the capacity auction clearing price, and can prevent these policy resources from clearing the market. Excluding these policy resources then causes the capacity auction to perceive a supply "gap" that it will seek to fill by clearing other, higher-cost capacity resources. MOPR-Ex therefore causes the auction to retain more existing capacity resources (such as coal plants that would otherwise retire) and/or attract new investments (such as new gas combined cycle plants that would not otherwise be built). The total amount of capacity available and operating would exceed the amount needed to meet the reliability objectives that the capacity market was designed to meet.

To evaluate the impacts of applying MOPR to policy resources, we conducted a simulation analysis of the PJM capacity market in a 2025 and 2030 study years in scenarios with: (a) the status quo of MOPR-Ex as applied to policy resources, and (b) no MOPR applied to policy resources such as under PJM's focused proposal.[43]

Our analysis shows that applying MOPR to policy resources will introduce several adverse consequences:

- MOPR-Ex will prevent state policy resources from clearing the capacity market and induce the uneconomic retention of excess capacity resources;
- MOPR-Ex will impose costs on consumers in two ways: first by causing them to pay higher capacity prices than is economically efficient (a cost that is borne by all customers, even those in states that have not supported any policy resources); and second by requiring customers in states with policy resources to "pay twice" for capacity (once for policy resources that cannot clear, and a second time for duplicate capacity that does clear);
- Higher prices would effectuate a wealth transfer from customers to suppliers on the entire volume of capacity transacted in the market, not just the excess resources; and
- Supporting excess capacity results in excess societal costs or deadweight loss that benefits neither customers nor suppliers (who bear the costs of maintaining the uneconomic excess supply).

The scale of these problems would grow with the scope of MOPR application and will grow over time as PJM states proceeds toward fulfilling their various clean energy mandates.

D.1. Approximately 6,800 MW of Policy Resources Could be Excluded from Clearing the Capacity Market by 2030

To assess the volume of policy resources that may be affected by MOPR-Ex, we reviewed the RPS and nuclear support programs of every state in the PJM footprint with the results summarized in Figure 4.[44]

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43 We conducted this analysis on behalf of the New Jersey Board of Public Utilities (BPU) as an input to their assessment of alternative resource adequacy structures. See Attachment A.

44 Our analysis accounted for carve-outs for certain resource types such as offshore wind, solar, and storage; we also deducted quantities anticipated from distributed solar. This analysis likely under-reports the total quantity of policy

Based on this analysis, we estimate that the total quantity of resources subject to the expanded MOPR PJM-wide could be approximately 11,500 UCAP MW by 2030 (more if states continue to expand their policies).

Not all of these resources will be precluded from clearing the capacity market. The majority of these resources are multi-unit nuclear plants earning ZECs and able to offer at zero MOPR price and thus, unless the MOPR floor price increases, would be unaffected by the expanded MOPR. In our analysis we have assumed that all of these resources will clear the market in 2030, though we note that Exelon recently announced that MOPR has prevented its 1,403 ICAP MW Quad Cities nuclear plant from clearing the 2022/23 capacity auction.[45] If Quad Cities or other nuclear units would always or sometimes fail to clear the auction, then the true costs of MOPR-Ex would be higher than we estimate in this testimony.

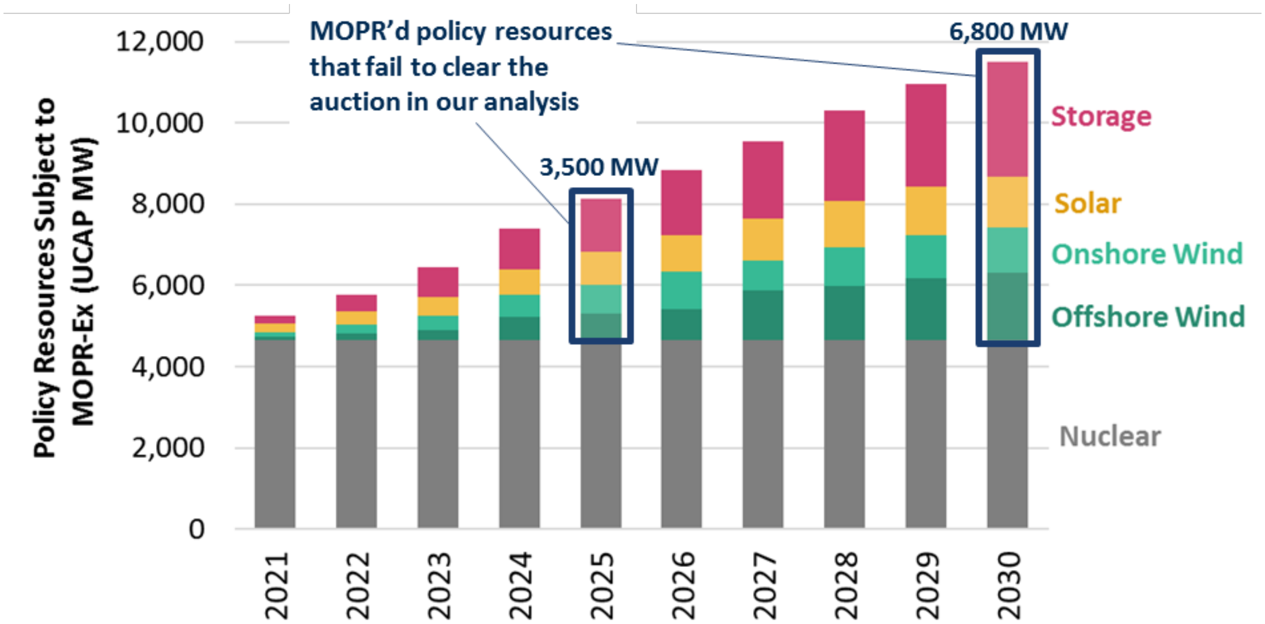
We also estimate that at default MOPR price levels (and after adjusting for projected resource cost declines), new onshore wind, offshore wind, solar, and storage resources are unlikely to clear the market. If some of these resources would be awarded a lower MOPR price that allows them to clear the auction, then the true costs of MOPR-Ex could be mitigated from our estimate. Overall, on a PJM-wide basis we estimate that approximately 3,500 UCAP MW of policy resources are at risk of not clearing by 2025, and up to 6,800 UCAP MW by 2030.[46]

resources that may be subject to MOPR-Ex given that we have focused on only a subset of states' policies. See additional discussion in Attachment A.

45 Edgar Glimpses, "Exelon Corp Files (8-K) Disclosing Other Events, Financial Statements and Exhibits," *EnergyCentral*, June 3, 2021; and Michael Yoder and Rich Heidorn Jr, "Stakeholders Discuss PJM Capacity Auction Impacts" *RTO Insider, LLC.*, June 3,2021.

46 Outlook developed based on an analysis of individual states' policy goals, existing resource mix, resource ratings, current MOPR price levels, and the outlook for resource cost declines. "2022/2023 BRA Default MOPR Floor Offer Prices for New Entry Capacity Resources with State Subsidy," PJM Interconnection, L.L.C. and "2020 Annual Technology Baseline," National Renewable Energy Laboratory.

FIGURE 4: VOLUME OF POLICY RESOURCES SUBJECT TO MOPR-EX



Sources and Notes: Developed based on an analysis of nuclear and renewable support standards of all states in PJM, accounting for the scale of resources that will need to be added to meet renewable and clean energy standards, any applicable technology carve-outs, deductions associated with distributed solar, and effective load carrying capability (ELCC) ratings.

D.2. MOPR-Ex Could Impose Approximately $1.7 Billion per Year in Excess Costs on Customers by 2030

Our analysis indicates that continuing to apply MOPR to policy resources would impose a significant cost on customers across the PJM region, amounting to $1.74 billion per year by 2025 and $1.70 billion per year by 2030 as illustrated in Figure 5. The detailed assumptions and results from this analysis are included in Attachment A. These excess costs appear in two ways: (1) as an increase in capacity prices affecting all transactions; and (2) as an increase in contract payments to policy resources because they are deprived of capacity market revenues that go instead to unnecessary substitute resources.

Our 2025 and 2030 cost impact estimates are similar in magnitude even though the volume of resources subject to MOPR-Ex will grow. This is because our 2025 analysis is a "short-run" analysis that utilizes supply offer prices and quantities that match offers in recent PJM auctions, as adjusted only for known changes to supply and projected demand increases.[47] In the short run (as represented by realized capacity auction supply curve shapes), the price impacts of MOPR-Ex and other policies that affect similarly-sized quantities of supply and demand could have a large price impact. Over the longer term however, the market would tend to react to very high prices with offsetting adjustments to their entry and exit decisions (thus moderating price impacts over the long term). Our 2030 cost estimates account for the offsetting effects of supply elasticity that could moderate price impacts from MOPR-Ex over the long term.

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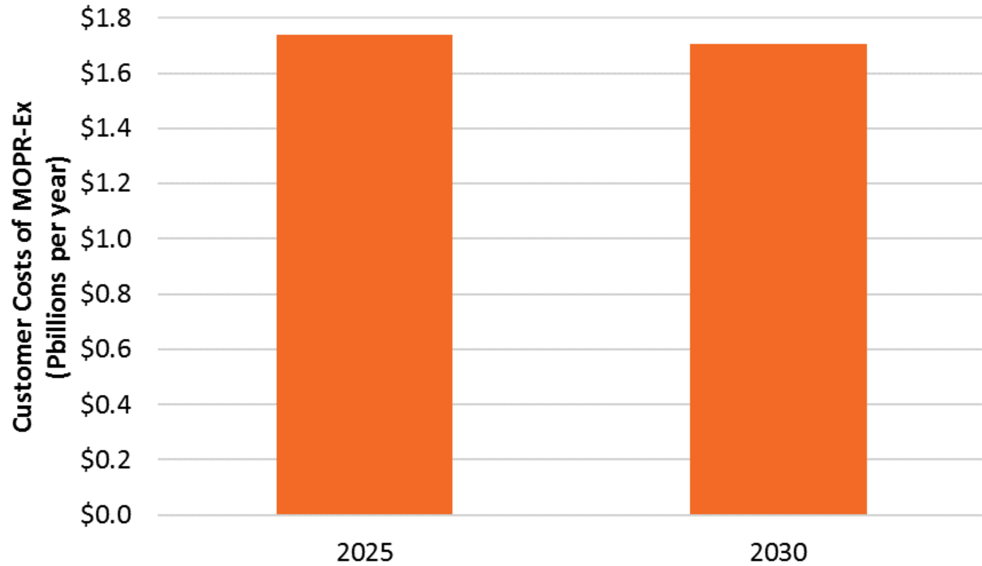
47 The capacity auction offer data used for that analysis were provided to us and the New Jersey BPU for the purpose of supporting their analysis of resource adequacy alternatives. See additional discussion of this modeling in Attachment A.

FIGURE 5: PJM-WIDE CUSTOMER COSTS IMPOSED BY MOPR-EX



Sources and Notes: See comprehensive modeling description and results in Attachment A, Section II.C, Appendix A, and Figure 20.

If more resources were subjected to MOPR-Ex and failed to clear the auction than we have assumed, the cost impacts would be higher. This could occur, for example, if states pursued additional policies beyond what we have accounted for or if nuclear resources were unable to clear the auction due to updates in the applicable MOPR-Ex price.

Conversely, the customer costs imposed by MOPR-Ex would be lower if the volume of resources excluded from MOPR were lower than we have estimated. For example, this could occur if many resources demonstrated lower costs and therefore cleared under resource-specific offer prices. The possibility that some resources could be allowed a low offer price and clear the auction would somewhat mitigate the adverse impacts of MOPR-Ex, but is not a reason that the rule should be maintained. Even if some policy resources cleared the market, others could be excluded, still causing the kinds of adverse impacts we have described, albeit with a smaller magnitude. These are costs that offer no offsetting benefits to the market. The only way to fully eliminate these costs would be to entirely eliminate MOPR-Ex from application to policy resources.

D.3. MOPR-Ex Imposes Excess Costs on Consumers in all States, with and without Substantial Policy Mandates

Customers in every state across the PJM footprint would bear a portion of the costs caused by MOPR-Ex. The largest costs would be imposed on customers in states whose policies support the largest UCAP MW volume of resources excluded from clearing the auction. But even in states with no policy resources excluded, customers would face excess costs from MOPR-Ex.

To understand why MOPR-Ex would impose costs so broadly across all customers, consider the impacts on customers in differently-situated states:

- **Customers in States with Substantial Policy Mandates:** In these states, consumers will face excess costs for two reasons: (1) the MOPR-Ex "price effect" that causes them to buy capacity at a higher price than is needed to support reliability, and (2) the "double payment" effect through which consumers must pay once for the capacity value of its policy resource (*e.g.*, through an all-in-bundled contract for offshore wind) and a second time for capacity through the capacity market (which must be procured only because MOPR-Ex has prevented the offshore wind from clearing). Of these two effects, the "price effect" is by far the larger contributor to customer costs at 88% of 2025 customer costs and 80% of 2030 customer costs. The price effect is large because the price increase is applied across the entire volume of the PJM market (the double-counting effect, while imposing a greater cost per MW excluded, applies to a smaller volume).

- **Customers in States with Few or No Policy Resources:** In these states, customers will face the price effect (but will not face a double-payment effect). Higher capacity prices caused by MOPR-Ex will be paid by all customers across the PJM footprint, regardless of which resources are excluded from clearing.
- **Customers in States that Utilize the Fixed Resource Requirement (FRR) Alternative:** Some states or utilities may exit the PJM capacity market under the FRR alternative as a means to utilize the capacity value of their policy resources. Under the FRR alternative, the state or utility can select its chosen policy resources and submit these resources as the FRR capacity plan to PJM to demonstrate that their customers' reliability requirements are fulfilled. For both Maryland and New Jersey, we have examined the options to mitigate MOPR-Ex cost impacts by pursuing such an FRR alternative. Across these separate studies, we estimated that a well-designed FRR mechanism could mitigate approximately 51-79% of the costs of MOPR-Ex depending on the approach.[48] In those cases, we found that there would be opportunities to avoid the costs of double-payment, but that they would be unable to avoid the price effect as long as they would seek to procure a portion of their capacity needs from resources that could sell into the RPM at a higher price.

The customer costs imposed by MOPR-Ex if maintained in its present form would thus be broadly felt by customers across the PJM footprint (though the exact share of these costs would differ amongst the states).

D.4. MOPR-Ex Could Induce Economic Inefficiencies of Approximately $0.3 Billion per Year by 2030

We estimate that approximately 6,800 UCAP MW of policy resources could be excluded from capacity auction clearing by 2030 (left side of Figure 6). Without these resources, the capacity auction will seek to fill a (fabricated) gap in supply needs. The "gap" will be filled by purchasing approximately 5,700 UCAP MW of higher-cost capacity that would not otherwise clear the market and that is not needed for reliability (right side of Figure 6).[49] Because the policy resources will be developed and operate in the energy market regardless of their capacity auction clearing status, the result that the total volume of resources exceeds what is needed for reliability (as represented by the capacity demand curve).

These excess capacity resources will be "marginal" resources that have offered at relatively high prices in the capacity market, at levels generally consistent with their net going-forward costs. For example,

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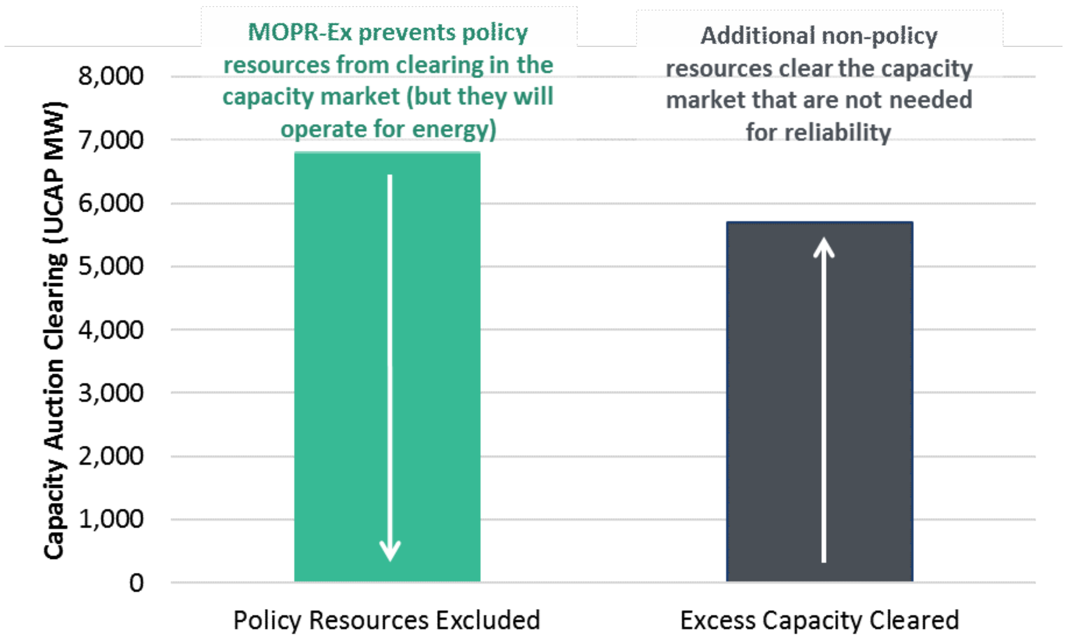
[48] See Attachment A and Kathleen Spees, Travis Carless, Walter Graf, Sam Newell, *et al.*, *Alternative Resource Adequacy Structures for Maryland: Review of the PJM Capacity Market and Options for Enhancing Alignment with Maryland's Clean Electricity Future*, prepared for Maryland Energy Administration, March 2021.

[49] The quantity of excess capacity procured via the capacity market is somewhat less than the quantity of policy resources excluded because at the higher capacity price caused by MOPR-Ex, the capacity demand curve procures a lower quantity of total supply.

these excess capacity resources could be high-cost aging fossil plants that require substantial re-investments to continue operating, or they could be new gas-fired power plants that require substantial new investments to be built. Regardless of what type of capacity is built to fill the phantom supply gap, every dollar spent to bring them online or keep them in service is a dollar of economic waste. Owners of these marginal resources are barely better off by clearing the market (as nearly every capacity dollar earned must be spent to maintain the high-cost resource); customers are far worse off because they must pay for excess capacity that has no reliability value.

We estimate that by 2030, MOPR-Ex will retain enough excess capacity to induce $0.3 billion per year in excess societal costs or deadweight loss that benefits neither customers nor suppliers.[50]

FIGURE 6: ESTIMATED CHANGES IN CAPACITY AUCTION CLEARING CAUSED BY MOPR-EX IN 2030



Sources and Notes: The quantity of excess capacity procured via the capacity market is somewhat less than the quantity of policy resources excluded because at the higher capacity price caused by MOPR-Ex, the capacity demand curve procures a lower quantity of total supply. See comprehensive modeling description and results in Attachment A, Section II.C, Appendix A, and Figure 20.

D.5. MOPR-Ex Could Induce a $1.4 Billion per Year Transfer Payment from Customers to Capacity Sellers by 2030 (But Harms to Customers Exceed Benefits to Sellers)

Incumbent capacity sellers are the primary beneficiaries of MOPR-Ex. However, the approximately $1.4 billion per year in net benefits that these incumbent players would enjoy by 2030 from maintaining MOPR-Ex are substantially below the $1.7 billion per year increases in costs imposed on customers as illustrated in Figure 7.

The reason for this discrepancy is associated with the economic waste induced by MOPR-Ex as illustrated in the figure. As discussed above, customer costs are increased according to the quantity effect (higher contract payments) and price effect (higher capacity market costs). The higher contract

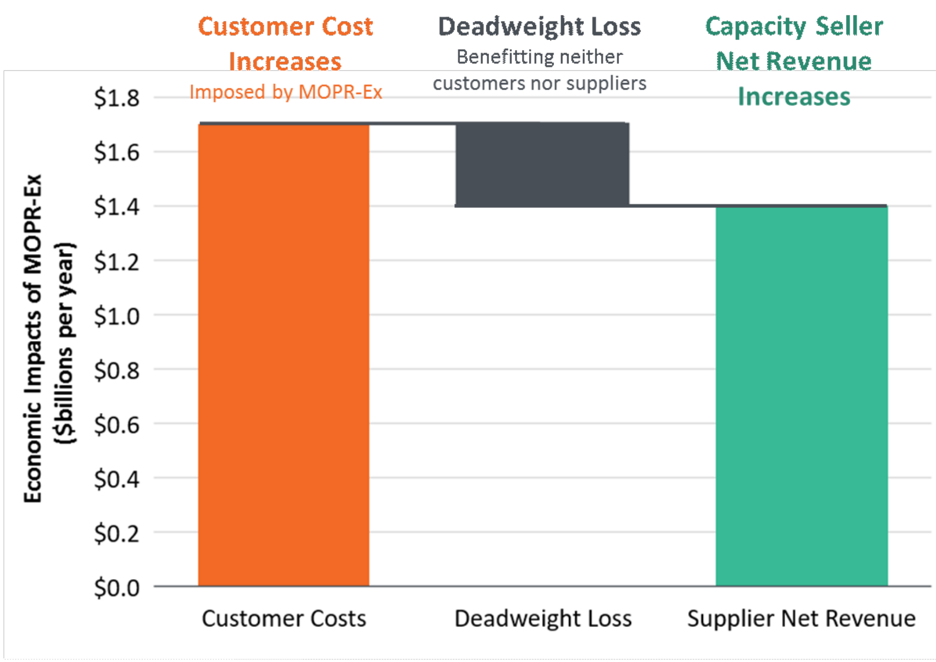
50 Calculated as approximately 5,700 UCAP MW of excess capacity that is retained under MOPR-Ex, multiplied by approximately $145/MW-day in average resource costs of the excess capacity; prices and quantities derived from Attachment A, Section II.C and Figure 20.

payments are earned by policy resources, making up for lost revenues from the capacity market (resulting in overall no net cost or benefit to policy resources that are subject to MOPR under the assumed contract/policy structure).

Other incumbent capacity sellers enjoy significant increases in capacity revenue as driven by higher capacity prices and by gaining a greater market share. This produces approximately $1.7 billion per year in increased capacity revenues to incumbent capacity by 2030. This increase in revenues, however, is partly offset by $0.3 billion per year in increased costs that are incurred to keep uneconomic resources online. Thus, the net benefits to capacity sellers is the remaining $1.4 billion per year.

Overall, the net benefits to incumbent capacity sellers from MOPR-Ex are lower than the costs to customers. This is because a portion of the customer costs from MOPR-Ex fund a $1.4 billion per year wealth transfer from customers to capacity sellers (benefitting capacity sellers at the expense of customers), while the remainder of customer cost increases are used to fund uneconomic investments to maintain aging fossil plants that would otherwise retire (benefitting neither customers nor generators).

FIGURE 7: IMPACTS ON PJM CUSTOMER COSTS AND CAPACITY SELLERS' NET REVENUES FROM IMPOSING MOPR ON POLICY RESOURCES BY 2030



Sources and Notes: See comprehensive modeling approach description in Attachment A, Section II.C, Appendix A, and Figure 20.

D.6. Professor Cramton's Analysis Complements and Confirms Our Own, Despite Methodological Differences

PJM's expert witness, Professor Peter Cramton, provides an assessment of the impacts of MOPR-Ex that largely aligns with our own. Professor Cramton similarly finds that MOPR-Ex induces systematic over-procurement, is not needed for reliability, and imposes excess costs on customers.[51] Our analysis does differ from Professor Cramton's in some respects, due to differences in modeling frameworks and assumptions. The primary differences are as follows:

- **Quantity of Resources Affected by MOPR-Ex:** We estimate that by 2030, MOPR-Ex will be applied to approximately 11,500 UCAP MW of policy resources (of which 6,800 UCAP MW would not clear the market). Our estimate of resources subject to MOPR-Ex is based on a detailed state-by-state analysis of existing supply (which is not subject to MOPR-Ex), growth in policy mandates, carve outs for specific technologies, deductions for distributed solar that are not affected by MOPR-Ex, and estimated ELCC ratings by resource type.[52] Professor Cramton adopts a lower assumption (as provided by PJM) that 3,417 MW of policy resources would be subject to MOPR-Ex by 2030.[53] Professor Cramton has not reported the details of how PJM developed this assumption, but we believe that an updated assessment of state policies would produce a higher number closer to our own considering the larger volume of policy resources that PJM has projected in its more recent planning outlooks.[54]
- **Quantity of Supply Excess:** Professor Cramton has estimated that MOPR-Ex would induce two percentage points more excess capacity than a focused MOPR, whereas we estimate a larger excess of approximately four percentage points. Again, this difference is caused by Professor Cramton's lower input assumption on the volume of policy resources subject to MOPR.
- **Impacts of MOPR-Ex on Prices:** Another difference is that Professor Cramton's simulations indicate that capacity prices are similar with or without MOPR-Ex, while we estimate that MOPR-Ex would cause approximately \$26/MW-day and \$25/MW-day increases in capacity prices in 2025 and 2030 respectively. This difference is explained by our different modeling approaches. Our approach utilizes an upward-sloping supply curve based on actual PJM capacity auction offer data (for 2025) and a more moderate but still upward-sloping longer-term supply curve (for 2030).[55] Because we have used detailed present market data to support this analysis,

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51 See Affidavit of Peter Cramton on behalf of PJM Interconnection, L.L.C, p. 12, Attachment C of Letter to Kimberly D. Bose from Craig Glazer, Chenchao Lu (PJM); Paul M. Flynn, Ryan J. Collins, Elizabeth P. Trinkle (Wright & Talisman), Re: PJM Interconnection L.L.C., Docket No. ER21-2582-000 Revisions to Application of Minimum Offer Price Rule July30, 2021 with attachments A–G and the more detailed paper describing the modeling approach: Peter Cramton, Emmanuele Bobbio, David Malec, and Pacharasut Sujarittanonta, *Electricity Markets in Transition: A multi-decade micro-model of entry and exit in advanced wholesale markets*, July 2021.

52 See additional detail in Attachment A, Appendix A.

53 In 2030, his reported number of resources subject to MOPR is 3,417 MW (not explicitly reported in either ICAP or UCAP terms). See Table 6.5 in Peter Cramton, Emmanuele Bobbio, David Malec, and Pacharasut Sujarittanonta, *Electricity Markets in Transition: A multi-decade micro-model of entry and exit in advanced wholesale markets*, July 2021.

54 For example, in a recent planning outlook, PJM has projected approximately 82,961 ICAP MW of offshore wind, onshore wind, solar, and storage will be needed to meet policy targets by 2035 (a projection that is similar to our own). However, to compare this number meaningfully to our own estimate of resources affected by MOPR-Ex, PJM's projected volume of policy resources would need to be converted to a UCAP basis and deduct resources not subject to MOPR such as existing resources and distributed solar as we have done. See p. 21 of "Offshore Transmission Study Group Phase 1 Results" August 10, 2021.

55 In our 2025 analysis, we used historical capacity auction offer data provided to the NJ BPU for the purposes of conducted this analysis; we updated these offer data to account for known entry and exit as well as the effects of MOPR-Ex. In our 2030 analysis, we accounted for long-term supply elasticity by adjusting existing generation resources' offer prices consistent with net going-forward fixed and operating costs, minus net energy and ancillary services revenues. This higher offer price accounts for the logic that an existing resource may remain in the market for

our approach provides the most robust estimate of near-term and medium-term MOPR-Ex cost impacts. By Comparison, Professor Cramton's model focuses on an even longer-term multi-decade timeframe over which the capacity supply curve becomes even more moderated (close to flat in the very long term relevant for his study), which explains is finding that prices are similar with or without MOPR-Ex.

- **Cost Impacts:** Regardless of any moderation in price impacts over a longer timeframes, we and Professor Cramton have similarly found that the MOPR-Ex would cause a perpetual and persistent over-procurement in capacity supply that is not needed for reliability. This excess supply induces both excess customer costs and economic waste.

Overall, our analysis and findings are consistent and complementary to those of Professor Cramton. Our analysis provides the most robust estimate of near- and medium- term magnitudes of MOPR-Ex price, cost, and quantity impacts, including accounting for a larger volume of resources that would be affected by the rule between now and 2030. Professor Cramton's modeling provides an assessment of the longer-term outcomes that could be expected (though an updated assessment of the volume of resources subject to MOPR-Ex would likely result in larger impacts). We use alternative and complementary approaches to arrive at the same conclusions that MOPR-Ex will induce excess capacity to be developed, impose excess costs on customers, and is not needed for reliability.

E. Competitive Markets must Acknowledge Policy Goals in Order to Enable the Greatest Benefits from Trade

Competitive wholesale electricity markets, including the PJM capacity market, have a long history of offering significant benefits to consumers by maintaining reliability at low costs. To continue offering these benefits in the future, the market will increasingly need to facilitate and accommodate states' clean energy mandates and other policy priorities.

E.1. The Capacity Market Must Recognize State Policies if it Is to Incentivize Private Actors to Make Cost-Effective Entry and Exit Decisions

State entities, like large buyers and resource owners, have many financial and non-financial reasons they may wish to develop capacity resources. This wide range of policy and business priorities will naturally affect supply resources' participation levels and offer prices within the PJM capacity market. Incorporating all offers into the regional market provides a common forum through which the wide variety of private and public interests come together through capacity auction clearing and price formation. Through this mechanism the common market informs public entities and private actors whether to proceed with their investments, which resources can be economically retired, and which types of policy resources offer the most capacity value (as measured in both reliability and economic terms). Public and private actors that utilize the regional capacity market to its fullest potential can substantially improve the cost-effectiveness of their policy and business decisions; actors that under-utilize the market will risk forgoing these benefits.

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a few years (i.e., the "short term") at low capacity prices, but will eventually exit if they are unable to recover their costs for the foreseeable future (i.e., the "long term"). See additional detail in Attachment A, Appendix A.

E.2. MOPR-Ex Threatens to Undermine the Future of Competitive Capacity Markets

Far from "protecting" capacity markets from the threat of price suppression and policy resources, the application of MOPR to policy resources threatens to undermine the benefits and eventually the very existence of competitive capacity markets. Applying MOPR to state policy resources erodes the benefits that a competitive capacity market can offer. It imposes unnecessary excess costs on customers and society, interferes with the ability to achieve states' policy goals, and effectuates a wealth transfer from customers to incumbent capacity sellers. These adverse economic outcomes are amplified in any region with a significant environmental policy and will rise quickly as states across the PJM region proceed toward achieving their ambitious clean energy mandates.

Eventually, the scope and scale of an MOPR-Ex would become so great that it could exclude the large majority of all resources from participating, especially in states with the most ambitious climate goals. At the same time, the capacity market would continue to produce the high prices that would be necessary to retain excess capacity resources consistent with a fictional scenario as though the states' policies did not exist. This outcome is nonsensical and unsustainable. Rather than force customers to endure persistent, growing, and unnecessary excess costs, state policymakers would be forced to exit the capacity market entirely. In fact, state policymakers in New Jersey, Maryland, and Illinois have engaged in proceeding on the future of resource adequacy in the state for this very reason; and Dominion has already exited the market via the FRR alternative.

The solution to this problem is simple: eliminate the application of MOPR to policy resources, and allow prices to reflect the intersection of supply with demand.

E.3. Wholesale Electricity Markets Can Offer Greater Economic Benefits by Offering Competitive Solutions for Aligning with and Achieving Policy Goals

More generally, well-designed competitive markets will greatly aid the cost-effective, reliable transition to a clean electricity grid. To preserve and expand the role of competitive markets in offering broad consumer benefits, they will increasingly need to align with and support states' environmental and other policy goals. The FERC has acknowledged the benefits of supporting state goals through the reflection of enhanced carbon pricing within wholesale electricity markets.[56] PJM has similarly adopted a strategic priority to "facilitate pursuit of policy-maker and consumer decarbonization objectives by establishing ourselves as a trusted, unbiased policy adviser & driving consensus for at-scale, market-based solutions where possible."[57] States, Independent System Operators (ISOs), and stakeholders will increasingly identify opportunities to enhance the markets for a decarbonized grid, such as through enhanced carbon pricing, enhanced energy and ancillary service market designs, and solutions for aligning the capacity market with state policy.[58] These reforms may take some time but will ultimately support the evolution toward a fit-for-purpose wholesale market supporting efficient, reliable energy transition.

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56 FERC, Docket No. AD20-14-000, "Carbon Pricing in Organized Wholesale Electricity Markets," October 15, 2020.

57 See PJM Interconnection, *PJM Strategy – Powering Our Future*, p. 10.

58 For example see the Integrated Clean Capacity Market concept described in Attachment A, Appendix B; and a range of solutions proposed within the PJM Carbon Pricing Senior Task Force.

F. Certification

We hereby certify that we have read the filing signed and know its contents are true as stated to the best of our knowledge and belief. We possess full power and authority to sign this filing.

Respectfully Submitted,

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August 20, 2021

ATTACHMENT A

Staff of New Jersey Bd. of Pub. Util. & Brattle Group, *Alternative Resource Adequacy Structures for New Jersey, Staff Report on the Investigation of Resource Adequacy Alternatives*, Docket No. EO20030203, (June 2021)

Alternative Resource Adequacy Structures for New Jersey

STAFF REPORT ON THE INVESTIGATION OF RESOURCE ADEQUACY ALTERNATIVES, DOCKET #EO20030203

AUTHORED BY STAFF OF NEW JERSEY BOARD OF PUBLIC UTILITIES

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JUNE 2021

NOTICE

This report was prepared by Staff of the New Jersey Board of Public Utilities (BPU) with research and analytical support from consultants at The Brattle Group. The report reflects the opinions of Staff members of the New Jersey BPU Staff the analytical findings of the individual consultants of the Brattle Group contributing to this study. This report does not necessarily reflect the opinions of New Jersey BPU Commissioners, nor other clients or consultants of The Brattle Group.

The information relied upon in this report included modeling assumptions finalized between December 2020 and April 2021; modeling assumptions have not been adjusted to reflect subsequent market events.

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Resource Adequacy Investigation Findings

In May 2020, the New Jersey Board of Public Utilities (BPU or Board) initiated an investigation into resource adequacy[1] alternatives, directing Staff to assess "whether New Jersey can achieve its long-term clean energy and environmental objectives under the current resource adequacy paradigm and, if not, recommend how best to meet New Jersey's resource adequacy needs in a manner consistent with the State's clean energy and environmental objectives, while considering costs to utility customers."[2]

Over the past year, the Board and Staff have collected extensive input and evidence from stakeholders through receipt of written comments, a series of work sessions, and engagement with regional stakeholders. The BPU has further engaged consultants at The Brattle Group to conduct a modeling assessment of several resource adequacy alternatives, examining the cost, financial risk, and likely environmental outcomes of each framework under consideration.

Based on this evidence, this investigation finds that:

- **Incorporating New Jersey's clean energy goals in the regional market is the most efficient way to provide New Jersey consumers with reliable, affordable, *and* carbon-free electricity.** A clean power grid is necessary to address the crisis of climate change. The transition to a clean energy future must happen, and will happen, with or without a working wholesale power market. But the transition to clean energy can be faster, better, more reliable, and more affordable if power markets are reformed to focus incentives toward achieving policy goals. Of the regional approaches evaluated by Staff, the Integrated Clean Capacity Market (ICCM) best incorporates New Jersey's clean energy targets into the regional energy and capacity markets, which would drive significant investment in zero-carbon generation at a modest increase to current system costs, resulting in a substantially cleaner New Jersey *and* PJM grid.
- **Existing regional market structures have fulfilled their design objectives to maintain reliability at competitive prices, but have lagged behind in addressing state clean energy policies.** To date, participation in competitive regional electricity markets has offered significant benefits to New Jersey ratepayers by offering access to a broad, competitive marketplace for reliability. New Jersey should continue to participate in these markets *if* doing so can be made to be consistent with the State's commitment to eliminating carbon emissions associated with electricity production. Reforming the problematic Minimum Offer Price Rule (MOPR) so that it no longer excludes state policy resources is a necessary, but not sufficient, step toward supporting state environmental policies. The current regional marketplace will not be a satisfactory system to serve New Jersey's reliability and public policy goals until our state's clean energy policies can be explicitly represented, such as through a clean energy market.
- **Regulatory developments at the regional and national level make it premature to consider leaving the regional market structure.** Staff carefully examined a number of resource adequacy alternatives that involved leaving the regional market and adopting a New Jersey-centric resource adequacy

[1] "Resource Adequacy" is the process of ensuring that there is a sufficient supply of electricity generating capacity, in the right areas of the electric grid, to reliably meet customer's need for electricity, plus an adequate buffer or "reserve margin," to accommodate periods of high demand or stress on the electric grid, or allow the grid to continue functioning even when isolated generation or transmission resources fail. Since restructuring, New Jersey has relied on the centralized, regional capacity market, run by PJM Interconnection, to meet our resource adequacy needs and ensure a reliable grid.

[2] "NJBPU Launches Investigation to Ensure State's Clean Energy Future Despite Federal Regulation that Favors Fossil Fuels," State of New Jersey Board of Public Utilities news release, March 27, 2020; *In the Matter of BPU Investigation of Resource Adequacy Alternatives*, Docket No. EO20030203 (March 27, 2020).

model under the Fixed Resource Requirement (FRR) alternative. Staff concluded that it would be premature to do so while important market reforms are being considered at the regional and federal level that could facilitate the rapid decarbonization of the electricity sector. New Jersey should continue to pursue the first-best outcome of a broad regional ICCM or other clean energy marketplace, as long as a regional clean energy market appears on track for timely implementation.

- **New Jersey should continue to explore the option to implement a New Jersey or multi-state ICCM under the FRR structure.** In case ongoing regional reforms fail to deliver the clean energy marketplace that New Jersey requires, the State should maintain the option to utilize the FRR alternative to implement the ICCM or a similar competitive auction design for meeting the state's reliability and policy requirements. Pursuing a New Jersey ICCM under the FRR structure would require a substantial effort to designate or create a qualified ICCM auction administrator, implement a successful auction, mitigate market power concerns, and enable future participation of other leading clean energy states.

Executive Summary

The State of New Jersey is committed to achieving a 100% clean energy economy by 2050, consistent with the mandates in the Global Warming Response Act, the Clean Energy Act, and Governor Murphy's Executive Order 28.[3] The New Jersey BPU and other state agencies are following through on these commitments with a range of policies and strategies described in the 2019 Energy Master Plan.[4] Policies, practices, and infrastructure across the energy landscape must adapt and advance in order to achieve these commitments at the most affordable cost. Among these critical reforms are advances to the PJM regional electricity marketplace.

Over the past two decades, PJM markets have for the most part performed well in their role to deliver power to New Jersey consumers reliably and at competitive prices. However, these markets include no path to reducing, and eventually eliminating, fossil fueled power plants, as mandated by New Jersey public policy and environmental goals. Instead, states with aggressive carbon reduction mandates, including New Jersey, are forced to develop increasingly elaborate workarounds to meet clean energy goals. For example, PJM wholesale market incentives, which are based on maintaining reliability at the least cost, have attracted large-scale investments in over 35,000 MW of new natural gas-fired plants into the PJM region since the 2015/16 delivery year.[5] The scale, speed, and competitive pricing at which these plants have been developed demonstrate the capability of a broad regional marketplace to mobilize private capital to achieve large-scale resource transformation without putting ratepayers at risk. However, the fact that these investments are made in new fossil plants rather than clean energy resources also demonstrates the fundamental disconnect between the current market design and New Jersey's clean energy future.

Another illustration of this growing disconnect was the December 2019 Federal Energy Regulatory Commission (FERC) order requiring PJM to expand the application of the MOPR to clean energy resources receiving environmental incentives from state policy makers.[6] The expanded MOPR has become a catalyst for states, environmental advocates, clean energy companies, and consumers to demand reforms to PJM's capacity market, the Reliability Pricing Model (RPM), that help, not hinder, state clean energy objectives.

Within its Resource Adequacy Investigation, the New Jersey BPU has been taking action to address this gap and identify a path forward for the state and the broader PJM region. Beyond the near-term issue of avoiding MOPR impacts, the Board sought input on the longer-term consistency between New Jersey's energy and environmental objectives and the current RPM capacity market design. The Board's consultants at The Brattle Group evaluated New Jersey ratepayer costs and clean energy outcomes across a range of resource adequacy alternatives identified within the Board's investigation. The high-level results of that assessment are summarized in Figure 1.

The charts demonstrate two main takeaways: *first*, that the lowest-cost resource adequacy market solution, the "No-MOPR" capacity market does not advance New Jersey's clean energy achievement as compared to the status quo; and *second*, that achieving 90%+ percent of clean energy can be achieved at modest costs through a PJM-wide or New Jersey-only ICCM approach to resource adequacy.

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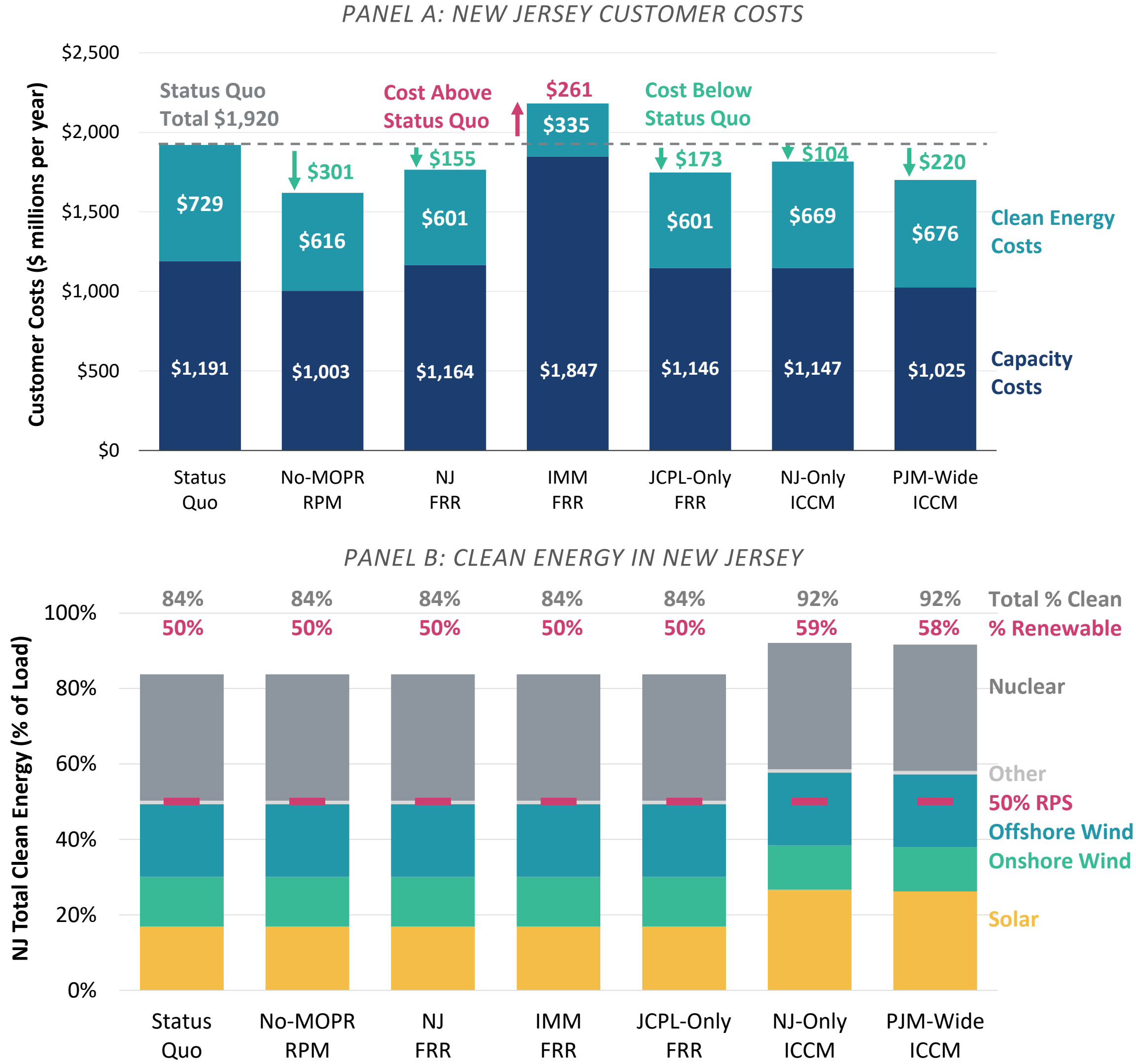
3 *See* State of New Jersey Department of Environmental Protection, "New Jersey's Clean Energy Picture" and New Jersey Government Executive Order No. 28.

4 *See* State of New Jersey Energy Master Plan.

5 PJM Interconnection, L.L.C., "2022/2023 RPM Base Residual Auction Results," Table 8.

6 *See Calpine Corporation et al. v. PJM Interconnection, L.L.C*, 169 FERC ¶ 61,239 (December 19, 2019). *See also* "FERC Directs PJM to Expand Minimum Office Price Rule," Federal Energy Regulatory Commission news release, December 19, 2019.

FIGURE 1: NEW JERSEY CUSTOMER COSTS AND SUPPLY MIX IN 2030 BY RESOURCE ADEQUACY DESIGN



The MOPR rules in effect as of June 2021, if left in place, will cost New Jersey customers approximately $300 million per year by 2030; PJM-wide customer costs will be approximately $1,700 million per year. The current MOPR is costly, directly opposes New Jersey's policy goals, and should be immediately repealed or significantly reformed. However, **Staff emphasizes that immediately eliminating the application of MOPR to policy resources is an essential, but by no means sufficient, step toward correcting the PJM markets.** Repealing or reforming the MOPR will do nothing to address the more fundamental disconnect between the PJM marketplace and New Jersey's clean energy transition. Accordingly, this investigation recommends that New Jersey Board and Staff should not only advocate for the elimination or reform of the MOPR, but also focus effort on the essential task of identifying a long-term sustainable market design that facilitates the efficient and cost-effective achievement of the State's clean energy goals.

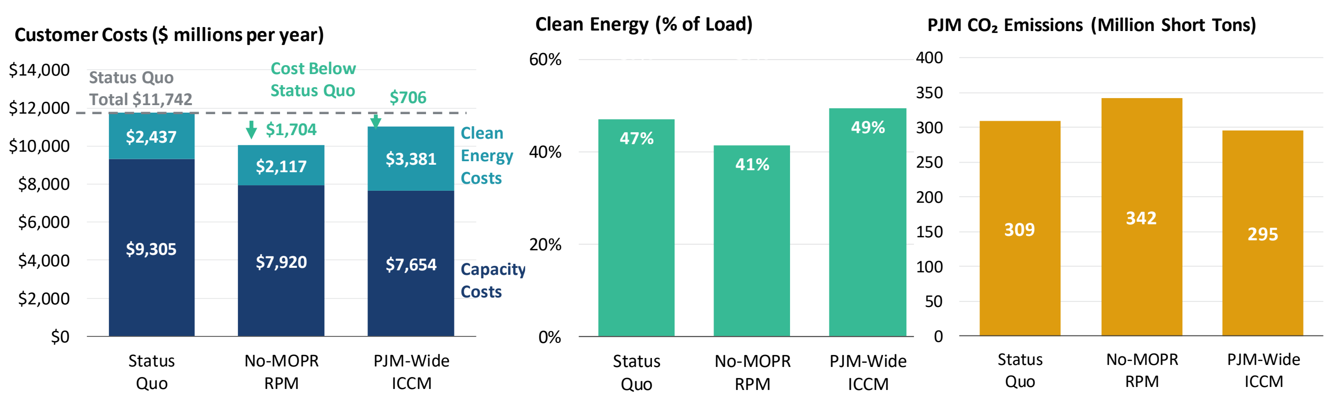
Throughout the investigation, commenters also proposed several avenues for New Jersey to manage its own resource adequacy responsibilities through use of PJM's FRR alternative. Some of the FRR alternatives are focused exclusively on limiting the customer cost impacts of the 2019 MOPR, but would pose a number of implementation risks. Under near-best-case assumptions, pursuing a MOPR-focused FRR could save approximately half the costs of a full MOPR repeal; under near-worst-case assumptions, an FRR could impose costs significantly in excess of the costs imposed under MOPR. Staff is currently monitoring PJM's MOPR reform efforts, and PJM states that it intends to implement a revised MOPR prior to the December 2021 auction (for delivery year 2023/24), which would eliminate the need to consider the FRR alternatives that are primarily oriented toward mitigating cost impacts from MOPR. Assuming the 2019 MOPR is repealed in a timely fashion, New Jersey should only consider pursuing an FRR alternative as a means to implement a resource adequacy structure that advances the State's clean energy goals.

Staff also examined the benefits of adopting a new market design, the ICCM, focused on meeting New Jersey's reliability and clean energy requirements in a competitive fashion. The ICCM would secure commitments to produce clean energy attributes three years in the future from clean energy resources that, when taken together, results in the lowest cost, reliable, electric grid that delivers on states' clean energy objectives. Staff examined two pathways to implement the ICCM, either: (1) through PJM-wide adoption of the ICCM as a replacement to the RPM; or (2) through a New Jersey or multi-state FRR ICCM construct. Staff concluded that both approaches would address the identified limitations of the current RPM design, and fulfill New Jersey's requirement to support the reliable, affordable, and carbon-free resource mix needed for grid transition.

Staff concluded that both of these pathways could address the limitations of the current RPM construct and advance New Jersey's clean energy goals at affordable costs. Compared to the status quo (with the current MOPR) a PJM-wide implementation of the ICCM could save New Jersey customers approximately $220 million per year, while a New Jersey ICCM implemented under FRR could save approximately $100 million per year. Both ICCM approaches would advance renewable energy from 50% to approximately 59% of New Jersey customer demand by 2030 (increasing from 84% to 92% considering renewables plus nuclear).

The PJM-wide ICCM has several advantages over the New Jersey ICCM however, given that the economic and environmental benefits would be amplified across the broad regional marketplace, as illustrated in Figure 2. The entire PJM footprint would advance clean energy from 41% (under No MOPR RPM) to 49% (under PJM-wide ICCM). The carbon impact of adopting ICCM on a region-wide basis would be similarly amplified, reducing PJM-wide carbon emissions by approximately 50 million tons per year (or 14%) by 2030. Depending on how states across the PJM footprint would choose to express their policy goals, the ICCM could be utilized to reduce the costs of meeting existing clean energy goals; accelerate renewable deployment; retain existing nuclear plants at risk for retirement; accelerate development of clean capacity resources such as demand response and storage; and/or enable customers to meet their own clean energy objectives. Such a marketplace would offer the greatest economic and environmental benefits if implemented across the broadest possible footprint. Thus, New Jersey should seek to achieve the ICCM or a similar solution on a PJM-wide basis as a replacement to RPM.

FIGURE 2: PJM-WIDE CUSTOMER COSTS, CLEAN ENERGY AND CARBON DIOXIDE EMISSIONS



In parallel to and partly in response to the Board's resource adequacy investigation, the Organization of PJM States, Inc. (OPSI), PJM Interconnection, and the FERC have each initiated separate efforts to repeal the 2019 MOPR and pursue broader capacity market reforms.[7] These initiatives demonstrate a growing understanding that PJM's capacity market must be reformed to align with the clean electricity future reflected in state policy goals. PJM processes beginning in July 2021 may offer one avenue through which New Jersey and other leading states can express the requirements that the new PJM market design must meet in order to support our clean energy future.[8] However, New Jersey cannot guarantee that a satisfactory resource adequacy market will be achieved through these reform efforts, nor that it will be implemented in the timeframe dictated by State policy goals. Staff therefore recommends the State continue to examine the use of an FRR structure to implement a New Jersey or multi-state ICCM.

[7] *See* Organization of PJM States, Inc. (OPSI), Letter of OPSI Principles to Guide PJM Market Design Evolution, January 8, 2021; Craig Glazer and Stu Bresler, "Capacity Market," PJM Interconnection, L.L.C, February 12, 2021; and Federal Energy Regulatory Commission "Technical Conference on Modernizing Electricity Market Design under AD21-10".

[8] *See* Adam Keech, Lisa Morelli, Dave Anders, "Capacity Market Workshop #4 –Next Steps," PJM Interconnection, L.L.C., March 26, 2021, p. 27.

I. Background

As a participant in the PJM wholesale power market since its inception, New Jersey has relied on the regional marketplace to provide low-cost and reliable electricity, which are the stated goals of RPM. While the regional competitive market has performed well in offering secure low-cost supply to New Jersey, the PJM wholesale power market was not designed to meet the State's growing demand for a cleaner electricity supply mix. At best, the current wholesale market is indifferent to carbon emissions; at worst, the wholesale market is acting at cross purposes to environmental goals (e.g., through the application of MOPR to clean energy projects incentivized through state programs and by attracting investments in new gas-fired power plants).

Because the PJM market does not yet account for the growing policy and consumer demand for clean energy, New Jersey meets these needs separately through its own programs. In recent years, New Jersey has implemented policies for a clean energy future including a 50% Renewable Portfolio Standard (RPS) by 2030 and planning a pathway toward 100% clean energy by 2050.[9] To meet its policy mandates, New Jersey incentivizes renewable energy resources to enter the market with competitive solicitations for offshore wind, a market for renewable energy credits (RECs), a zero emissions certificate (ZEC) program for retaining existing nuclear resources at risk for retirement, support for solar and storage resources, and various other policy incentives.

As a foundation for this investigation, Staff has reviewed the workings of the current PJM capacity market and its interactions with other aspects New Jersey policy to identify the components of RPM that misalign with New Jersey's stated clean energy future and identify the needed reforms.

A. New Jersey's Energy Policy Goals

New Jersey has ambitious goals to reduce greenhouse gas emissions and eliminate fossil fuel generation from its supply mix. The State's RPS, last updated in 2018, requires transitioning to a 35% renewable power supply by 2025 and 50% renewable by 2030.[10] The State has also set a goal of 7,500 MW of offshore wind energy by 2035.[11] Further, the 2019 Energy Master Plan outlined strategies to reach Governor Phil Murphy's administration's goal of 100% clean energy by 2050.[12] Finally, New Jersey also supports in-state nuclear resources through ZECs.[13] Figure 3 summarizes the mix of renewable and nuclear supply that will contribute to New Jersey's clean energy supply consistent with the 2019 Energy Master Plan, 50% by 2030 RPS, ZEC program, and other clean energy mandates.

9 *See* "2019 New Jersey Energy Master Plan: Pathway to 2050," New Jersey Board of Public Utilities, accessed May 7, 2019.

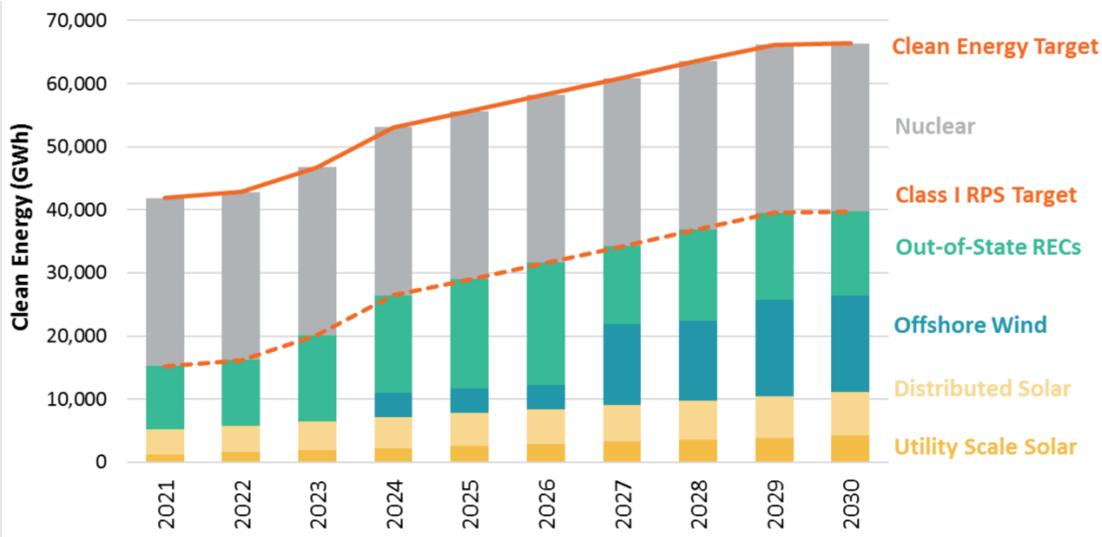
10 The renewable portfolio standard also requires a minimum amount of sales to be served from qualifying solar electric generation, decreasing from 5.1% in Energy Year 2021 to 1.1% by Energy Year 2033. These requirements are in addition to 2.5% of electricity which must come from qualified Class II renewable energy sources. *See also*, "New Jersey," PJM Environmental Information Services.

11 State of New Jersey, *Executive Order no. 92*, November 19, 2019, accessed May 7, 2021.

12 For order directing the completion of the 2019 Energy Master Plan, see State of New Jersey, *Executive Order no. 28*, May 23, 2018; For energy master plan, see State of New Jersey, "2019 New Jersey Energy Master Plan Pathway to 2050."

13 *See* N.J. Stat. § 48:3-87.8(d), approved May 23, 2018.

FIGURE 3: CLEAN ELECTRICITY SUPPLY TO MEET NEW JERSEY CLEAN ENERGY MANDATES THROUGH 2030



Sources and Notes: Nuclear is eligible for support under the ZEC program. RPS target and solar carveout obtained from PJM Environmental Information Services, "Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States," August 19, 2020. Percentage targets converted to MWh using BPU jurisdictional load subject to RPS in 2020 scaled by the PJM growth rate for New Jersey wholesale load from the 2021 PJM Load Forecast Report. Solar generation calculated based on existing capacity as reported in the BPU November 2020 Installation Report, assuming an additional 250 ICAP MW each per year for both behind-the-meter solar and grid supply solar, and a 15% capacity factor. Offshore wind generation based on New Jersey solicitation schedule assuming 1,800 MW procured for 2027 and 600 MW procured for 2029, and capacity factors of 40% for the first 1,100 MW procured and 50% thereafter. *See* "Governor Murphy Announces Offshore Wind Solicitation Schedule of 7,500 MW through 2035," Office of the Governor of the State of New Jersey press release, February 28, 2020. Out-of-state RECs calculated as balance in energy required to meet New Jersey's RPS goals. Nuclear generation estimated using 2019 historical generation from Form EIA 923.

B. The Role of PJM's Capacity Market in Supporting Reliability

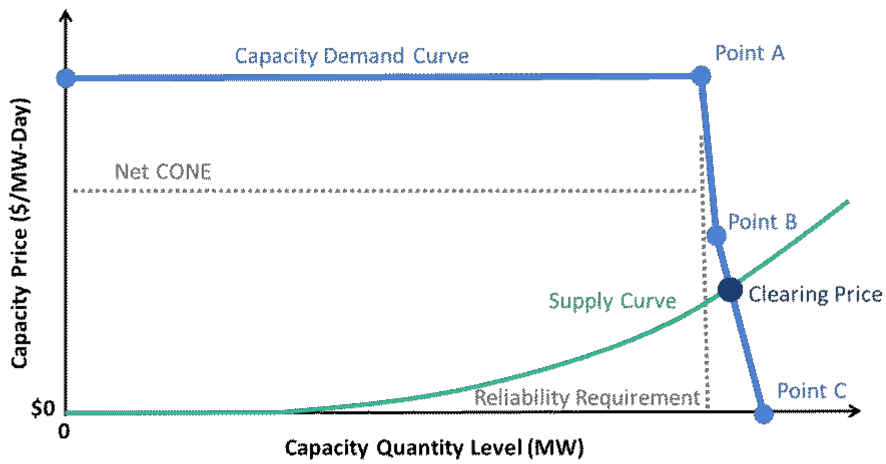
PJM's capacity market, the RPM, is a market-based system for procuring commitments from capacity resources that must be available to meet system and locational reliability needs. The quantity of capacity procured must be sufficient to meet a reliability standard of no more than *one expected loss-of-load event in ten years* (0.1 LOLE or 1-in-10). PJM establishes a reliability requirement based on forecasted peak load plus the installed reserve margin (IRM) needed to maintain 1-in-10 reliability. The capacity market aims to procure sufficient generation, storage, or demand response to meet reliability needs at the lowest possible cost through the three-year forward competitive Base Residual Auctions (BRAs). The RPM uses locational pricing that reflects transmission system limitations and uses a pay-for-performance incentive and penalty structure to incentivize resources to deliver on their capacity commitments during reliability events.

PJM uses an administratively-determined Variable Resource Requirement (VRR) curve to procure capacity under the RPM, as illustrated in Figure 4. The VRR is a downward-sloping demand curve that specifies the prices and demand relative to the IRM.[14] Prices in the VRR curve are tied to the administrative estimate of the Net Cost of New Entry (Net CONE), which is the price at which new generation resources would be

[14] PJM Interconnection Capacity Market & Demand Response Operations, "PJM Manual 18: PJM Capacity Market," Revision 47, January 27, 2021, Section 3.

willing to enter the market. System wide and locational VRR curves are designed to allow for the procurement of sufficient capacity to achieve resource adequacy, mitigate price volatility, and mitigate the ability for sellers to exercise market power.[15] Market participants with existing resources are required to offer available capacity into the RPM. New resources (not subject to MOPR provisions) may also offer into the market as price takers or at prices that reflect their individual net costs of entering.[16] The intersection of market participant supply offers and the VRR curve in each location sets the market price paid to all cleared capacity resources for the relevant one-year delivery period in that location. Supply resources unable to meet their capacity commitments are subject to deficiency and penalty charges. RPM prices are designed to be consistent with supply-demand conditions; the RPM produces low prices when there is more than enough supply to meet resource adequacy needs and high prices when capacity supply is scarce.

FIGURE 4: ILLUSTRATIVE PJM CAPACITY SUPPLY AND DEMAND CURVES



Historically, the PJM capacity market has been able to attract new investment and procure capacity that exceeds the reliability requirement, and at prices below the administrative estimate of Net CONE. Since the 2007/08 delivery year, 46,000 ICAP MW of new generation capacity has been attracted into the PJM capacity market, with an additional 11,000 ICAP MW from uprates to increase the output capability of existing resources. Beyond these additions of generation capacity, RPM has attracted other sources of capacity supply. Demand response and energy efficiency have increased by 15,000 ICAP MW, and net capacity imports have increased by 3,000 ICAP MW. These incremental capacity resources have been sufficient to meet increases in regional demand and replace large quantities of retirements from aging coal, nuclear, oil-fired, and high-heat rate natural gas plants.[17]

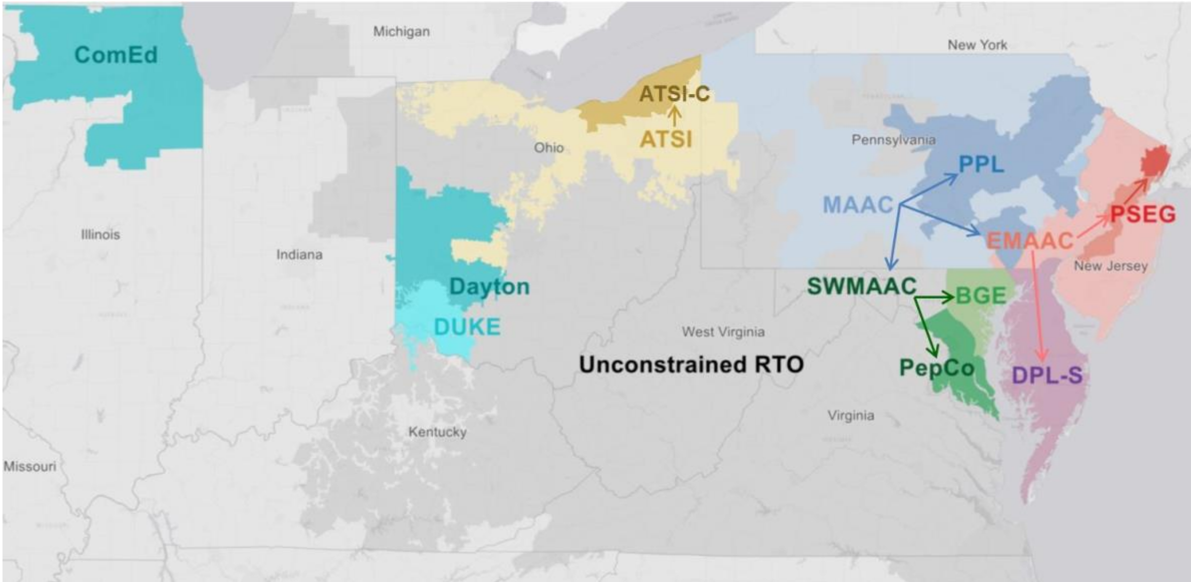
PJM uses the capacity market to procure capacity across the region to meet system-wide and local reliability needs at the lowest possible cost. Subregions of PJM with limited import capability due to transmission constraints are modeled as separate Locational Deliverability Areas (LDAs). Figure 5 shows a map of LDAs that are currently modeled in the RPM.

[15] Samuel Newell *et al*. "PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date," April 19, 2018.

[16] Seller offer prices are driven primarily by their going-forward investment and fixed costs minus any net revenues they anticipate to earn from selling other products such as energy, ancillary services, or RECs. Many capacity resources offer at a zero price if they have already come online and have few going-forward capital investments or can pre-sell most of their capacity or energy through bilateral contracts. Participants may also adjust their capacity offer price based on their long-term view of future energy and capacity prices.

[17] PJM Interconnection, L.L.C, "2022/23 RPM Base Residual Auction Results," May 23, 2018, pp. 20, 22, and 24.

FIGURE 5: MAP OF MODELED LOCATIONAL DELIVERABILITY AREAS IN PJM



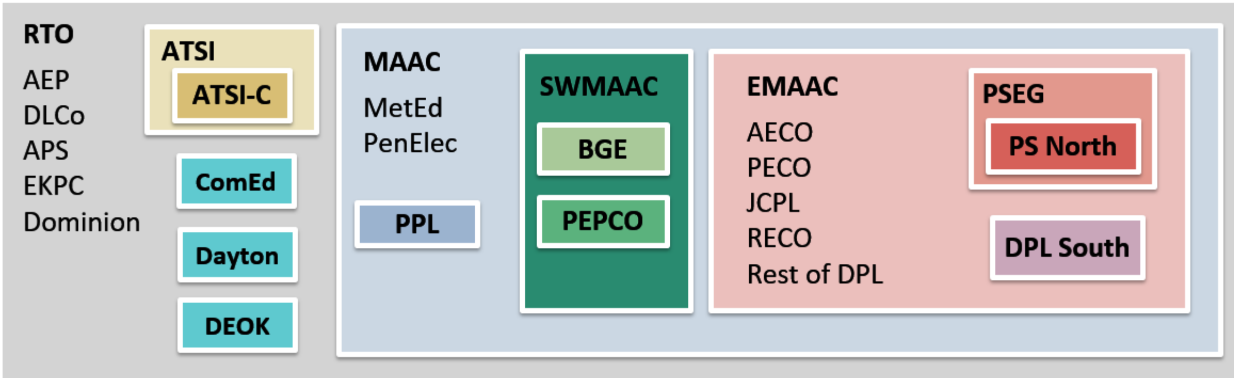
Sources and Notes: Samuel Newell *et al.,* "Fourth Review of PJM's Variable Resource Requirement Curve," April 19, 2018, Figure 1. The map represents modeled LDAs as of 2022/23.

Modeled LDAs each have a locational VRR curve, local Reliability Requirement, and locally estimated Net CONE. A "nested" LDA structure is used to reflect the transmission topology across the PJM system, in which successively smaller LDAs can procure capacity locally or from larger "parent" LDAs. Each LDA must have enough capacity procured to meet the local reliability requirements but can import a portion of that capacity from the parent LDA up to the maximum quantity that the transmission system can support or the Capacity Emergency Transfer Limit (CETL).[18]

This complex transmission topology is illustrated in Figure 6 below. Note that modeled LDAs in the capacity market do not necessarily align with utility service territories or state boundaries. The State of New Jersey comprises all or parts of three distinct modeled LDAs: EMAAC, Public Service Electric and Gas Company (PSEG), and PSEG North (PS-North). In addition, New Jersey can serve a portion of its capacity needs through imports from its parent LDA, the Mid-Atlantic Area Council (MAAC). Each modeled LDA has separate reliability parameters that must be achieved and each may produce distinct capacity clearing prices. The RPM reflects these transmission constraints within auction clearing by optimizing capacity imports to meet the reliability needs of all LDAs at the lowest cost. By participating in a broad regional marketplace, New Jersey can save costs by importing lower-cost capacity (to the extent possible) while ensuring that sufficient local capacity will be available for reliability needs.

[18] *See* "Special Planning Committee: CETO/CETL Education," PJM Interconnection LLC, accessed May 7, 2021.

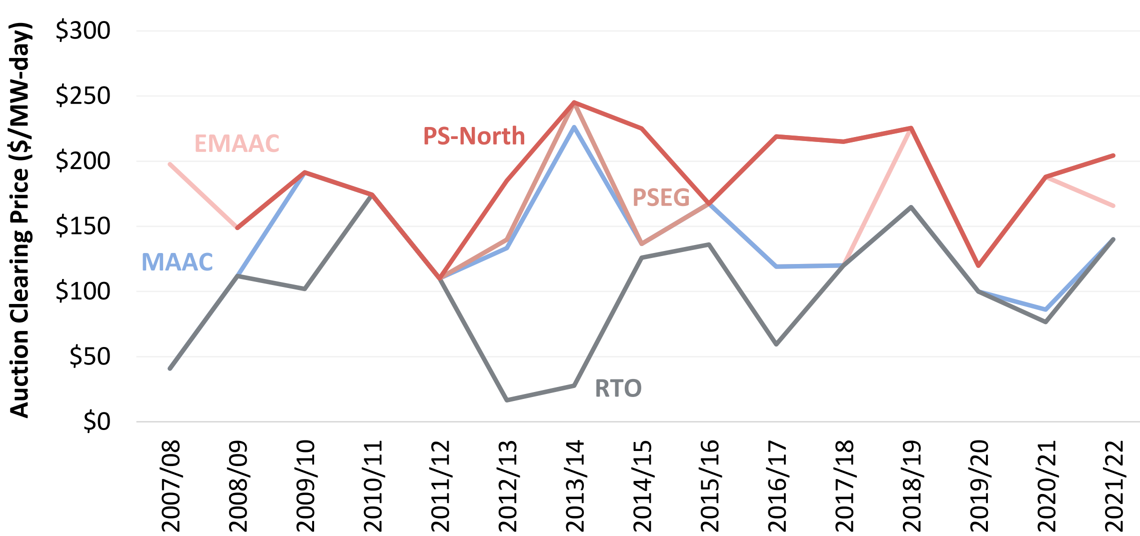
FIGURE 6: SCHEMATIC OF NESTED STRUCTURE OF LOCATIONAL DELIVERABILITY AREAS



Sources and Notes: The nested schematic is from Samuel A. Newell *et al*., "Fourth Review of PJM's Variable Resource Requirement Curve," April 19, 2018, Figure 10. Each rectangle and bold label represent an LDA modeled in the 2022/2023 RPM Base Residual Auction Planning Parameters; individual energy zones listed in non-bold without boxes are not currently modeled. See list of acronyms for full LDA names.

Under the RPM pricing structure, import-constrained LDAs can experience higher clearing prices relative to their parent LDAs due to transmission limits and tight local supply-demand balance. The smaller LDAs have equal or higher prices as compared to the parent zones and can produce occasional price spikes due to the relatively large price impact from small changes in supply, demand, and transmission parameters. Higher prices in constrained LDAs can serve as a signal to attract new investment in supply resources that are needed to support local reliability requirements, even though developing capacity resources may be more expensive in these locations.

FIGURE 7: CAPACITY CLEARING PRICES IN THE NEW JERSEY LDAS



Sources and Notes: Monitoring Analytics, "2019 State of the Market Report for PJM: Volume II, Section 5 – Capacity Market," March 12, 2020, Table 5-21. See list of acronyms for full LDA names.

C. Interactions between the Capacity Market and Clean Electricity Mandates

Currently, 11 out of 14 PJM states have established RPS programs to support clean energy goals.[19] While today's RPM was not designed to incorporate state clean energy policies, there are certain interactions between clean energy policy and capacity market outcomes in the interconnected regional market. There are some aspects of the wholesale power markets that beneficially complement and support clean energy policies, but other aspects that tend to work at cross purposes with these state policies.

In terms of beneficial interactions with clean energy policies, wholesale power markets offer a ready marketplace for clean energy resources to sell energy, capacity (subject to MOPR application), and (if relevant) ancillary services at a fair price. Depending on the resource type, a share or even the majority of the resources' investment costs can be paid for through participating in the wholesale markets, thus reducing the net cost of the state's clean energy policy programs. These transparent, open markets create opportunities for innovative players such as in the demand response and battery storage space to identify new technologies and business models for providing reliability services to the grid.

The wholesale markets further offer balancing services to complement the output profiles of intermittent resources and maintain reliability, such that the cost of integrating renewables in the PJM region has been modest to date. The "network access" approach to ensuring transmission sufficiency ensures that clean energy resources across the PJM system are simultaneously deliverable to load centers. Several jurisdictions including New Jersey, Pennsylvania, Maryland, Delaware, and Washington, DC allow RECs to be purchased across state lines to help meet their clean energy goals and access lower-cost clean energy.[20]

State policies to support clean energy resources also impact the wholesale markets, by displacing other resources that would have supplied the energy and capacity to the grid. When the clean energy resources displace fossil plants, this achieves state environmental goals by causing reduced emissions by reducing operation (in the energy market) or commitment (in the capacity market) of coal and gas power plants. However, the markets do not presently have any means for a state to select the clean energy resources desired to achieve state environmental policy goals, including those laid out in New Jersey's mandates.

Moreover, the type of REC-based clean electricity mandates most common in the PJM region have historically addressed only megawatt-hours of electricity, and do not address when the power is delivered, or whether the resources supplying the clean energy are capable of keeping the grid reliable. This concern only increases as RPS or clean energy standards (CES) programs start approaching 100% clean energy. For example, a 100% RPS standard would offset in-state fossil fuel generation with carbon-free electricity generated somewhere in the PJM footprint, but it would not directly address reliability concerns or the fact that the state is relying on fossil generation to keep the lights on. While shifting to a time-of-use RPS or other "advanced" REC product may lessen these concerns, the fact remains that the existing PJM market does not provide consumers or policy markets any levers to limit their reliance on fossil fuel generation, especially for resource adequacy purposes.

Overall, there is a substantial and growing disconnect between the design of the wholesale power markets and state clean energy mandates. Namely, the capacity market aims to meet reliability needs (but is indifferent to carbon emissions or other energy policy goals) and will attract investments in whatever type

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19 PJM Environmental Information Services, "Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States," August 19, Environmental Information Services, PJM Interconnection LLC, August 2020.

20 Skyler Marzewski, Devendra Canchi, and John Hyatt, "State RPS Fulfillment," Monitoring Analytics, October 24, 2019, p. 4.

of capacity resource is available at the lowest cost. Recently, the lowest-cost resources attracted into the PJM capacity market have been natural gas-fired power plants, with approximately 29,000 MW of new natural gas-fired plants into the PJM region over the past 6 years.[21] At the same time, the wholesale power market has not provided sufficient financial incentives to attract new renewables or retain certain existing nuclear resources that will be needed for a cost-effective transition to a decarbonized electricity grid. This disconnect illustrates the need to reform the wholesale power markets to incorporate states' and consumers' decarbonization requirements as a foundational market design goal (alongside maintaining reliability and minimizing cost).

The rules of PJM and other regions' power markets were developed at a time when the resource mix was dominated by large central power stations, fossil fuel resources, and when state clean energy goals were modest. The RPM capacity market is a product of the assumptions and resource mix relevant at that time; with rapidly evolving landscape of energy resources and increasing clean energy goals across PJM states, many of these assumptions are no longer valid. Staff conducting this investigation appreciate the PJM Board's recent recognition of this rapid evolution.[22]

Looking ahead, a new market design aligned with a decarbonized energy grid should assume that clean energy resources including renewables, nuclear, demand response, batteries, and distributed supply will increasingly dominate the resource mix. Consumers, states, and PJM must be able to rely on these emerging resources to fulfill increasing shares and eventually 100% of all reliability needs, at least within those subregions serving states that choose to adopt 100% clean electricity mandates. A resource adequacy structure designed in alignment with this future could have a number of features in common with the current RPM capacity market, including least-cost achievement of design parameters, reliance on a competitive, technology-neutral, market design, a three-year forward procurement cycle, minimization of barriers to entry, transparency in market parameters and pricing, and robust monitoring and mitigation.

The reforms needed to better align the capacity market and broader PJM markets with state clean energy goals are substantial and may take many years of effort and active engagement to implement. PJM's recent commitments to support state policy goals in alignment with the principles established by OPSI are a significant step in that direction, but the number and scope of essential reforms must be understood as a fundamental and foundational shift across all aspects of the power market design in order to match the scale and timeframe of the task at hand.

II. Impacts of the Minimum Offer Price Rule in New Jersey

Among the key stated goals of this investigation was an analysis of whether New Jersey can achieve its long-term clean energy and environmental objectives under the current resource adequacy paradigm, with specific reference to the 2019 MOPR.[23] This ruling expanded the application of the MOPR to apply a

[21] PJM Interconnection, L.L.C., "2021/2022 RPM Base Residual Auction Results," May 23, 2018, p. 22.

[22] *See* Letter from the PJM Board of Managers to PJM Stakeholders dated April 6, 2021. ("[T]he PJM Board acknowledges that our industry continues to evolve rapidly. The capacity market should be part of this evolution. While it has served its originally stated purpose and achieved sound results, it is now timely to consider whether certain elements of it need to change to continue to meet our collective future needs.")

[23] *In the Matter of BPU Investigation of Resource Adequacy Alternatives*, Docket No. EO20030203 (March 27, 2020).

floor price to resources that receive state subsidies,[24] and was adopted over the objections of the New Jersey BPU.[25] The expanded MOPR, if maintained in its present form, will limit the ability of new renewable energy resources to clear the PJM capacity market and impose excess costs on New Jersey's customers. Accordingly, this investigation finds that the 2019 MOPR actively interferes with achievement of New Jersey's long-term clean energy and environmental priorities. New Jersey should continue to advocate for repeal and/or significant reform of the 2019 MOPR as a threshold first step in any PJM capacity market reform to accommodate state clean energy policy.

A. The Minimum Offer Price Rule and its Application to Policy Resources

The original and appropriate economic purpose of the MOPR is to protect the market from the exercise of buyer-side market power. Specifically, schemes where large net buyers or their contractual counterparties offer a small amount of uneconomic supply into the market below cost in order to artificially suppress market-clearing prices.[26] By taking a loss on that small sell position, a large net buyer could then benefit from low prices on a much larger buy-side position in the market. The MOPR is designed to ensure that entities with the incentive and ability to engage in manipulative price suppression would be unable to do so by requiring their capacity market offers to reflect their full costs. Uneconomic new resources sponsored by large net buyers would fail to clear (or would set the prices at a higher level) and prevent the entity from achieving the benefits of manipulative price suppression. Symmetrical rules are imposed on large net sellers of capacity in order to prevent them from exercising economic or physical withholding.

In December 2019, FERC issued an order expanding the scope of MOPR to apply to new or existing resources that receive state subsides, such as RECs and ZECs.[27] Exemptions apply only to existing resources that have previously cleared an auction or new resources that had an interconnection agreement prior to the December 2019 order.

The rationale for the expanded MOPR was accepted by FERC as of the December 2019 order, but is no longer accepted or shared by the majority of FERC commissioners. At the time, the FERC's rationale for having expanded MOPR to policy-supported resources was to "protect" prices in the competitive market from being suppressed by state-sponsored resource planning decisions. State policy support will tend to attract incremental clean energy supply, displace fossil generation that would otherwise be built (or allow additional aging plants to retire), and reduce prevailing capacity market prices. Under FERC's theory as of the December 2019 order, these lower prices amount to an artificial "suppression" of market prices; applying an expanded MOPR "corrects" market prices to the higher level that would prevail absent states' policies.[28]

24 *Calpine Corporation et al. v. PJM Interconnection, L.L.C*, 169 FERC ¶ 61,239 (December 19, 2019).

25 *See* Request for Rehearing of the New Jersey Board of Public Utilities, EL16-49-000, July 30, 2018; Initial Argument of the New Jersey Board of Public Utilities, EL18-178-000, October 2, 2018; and Reply Argument of the New Jersey Board of Public Utilities, EL18-178-000, November 6, 2018.

26 A "net" buyer is one whose purchases are larger than their sales. If an entity has a large net buyer position, they may have the incentive to suppress capacity prices in order to secure power at lower total costs.

27 *Calpine Corporation et al. v. PJM Interconnection, L.L.C*, 169 FERC ¶ 61,239 (December 19, 2019).

28 *Calpine Corporation et al. v. PJM Interconnection, L.L.C*, 169 FERC ¶ 61,239 (December 19, 2019).

Instead, state policies such as New Jersey's aim to address the market's failure to recognize environmental externalities, such as carbon and other air pollutants emitted in the production of electricity. Renewable energy credits and other forms of support for carbon-free generation technologies is a rational attempt to recognize the value of the environmental externalities.[29] While the policy support these resources receive does reduce their net cost of providing capacity, the intent of clean energy incentives is not to affect wholesale market prices, but to incent the transition to cleaner sources of electricity. The "competitive" cost of providing capacity for these policy resources can be low, or even zero, as they are primarily developed for other reasons other than for earning capacity payments. Imposing a price floor on such resources and ignoring the capacity value they provide distorts the market, rather than correcting it. Excluding policy resources causes the market to procure more capacity than needed and improperly raises prices above the level corresponding to actual supply and demand conditions.

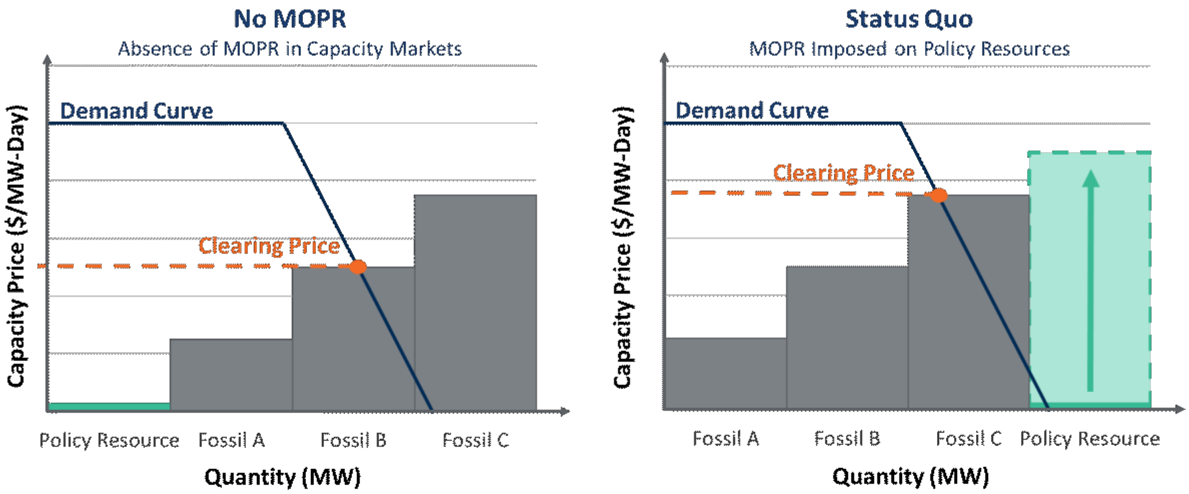
Figure 8 illustrates the impact of MOPR on the ability of policy resources to clear the capacity market. The "No MOPR" scenario on the left illustrates clearing outcomes if all capacity resources are allowed to offer at their preferred offer price.[30] Many policy resources would prefer offer at a near-zero price, especially if they would be developed regardless of the capacity revenues they receive. Fossil plants and other capacity resources' competitive offer prices would typically reflect the payments needed to cover their net avoidable going-forward costs (that is, economic costs they will incur as a result of providing capacity in the delivery year that they would not otherwise incur). Clearing prices are set at the intersection of supply and demand, as illustrated on the left panel of Figure 8.

The right-hand panel, however, illustrates the application of MOPR to a policy resource. The MOPR raises the offer price of the policy resource relative to the No MOPR scenario and reorders the capacity market offer supply curve. As the MOPR level exceeds the capacity clearing price, the policy resource does not clear, and the market's incremental capacity need is met by fossil resource C at a higher price.

29 For a comprehensive discussion of the uneconomic basis of the MOPR, see New Jersey BPU, pp. 8-9 "Attribute Compensation Programs Correct for Long-Standing Deficiencies in FERC's Market, Are Economically Efficient, and Should Not Be Mitigated," November 6, 2018.

30 For illustration, we show a policy resource offering into the capacity market at zero. In reality, policy resources may choose to offer at higher prices even without the MOPR depending on their individual circumstances. However, the restriction imposed by MOPR is to force policy resources offer at high prices above what would be required for them to supply capacity.

FIGURE 8: IMPACT OF MOPR TO EXCLUDE POLICY RESOURCES AND INCREASE CAPACITY MARKET PRICES



The policy resource offers at zero in the absence of MOPR to ensure clearing the capacity market.

The expansion of MOPR would artificially increase the price of the policy resource and prevent it from clearing the capacity market. As a result, the clearing price would increase.

Overall, applying MOPR to policy-supported resources in New Jersey can be expected to lead to the following undesirable effects:

- Limiting the ability for clean energy resources to generate revenue and interfere with New Jersey's clean energy mandates.
- Retaining uneconomic high volumes of capacity supply that is unnecessary for reliability.
- Retaining aging fossil plants that will impede New Jersey's transition to clean electricity.
- Causing higher market clearing prices exceeding the level corresponding to actual supply conditions and causing a large wealth transfer from customers to incumbent suppliers.
- Driving an unsustainable market as these distortions become larger over time under New Jersey's statutory mandate to achieve 50% renewable electricity (84% total clean energy including nuclear) by 2030, and 100% clean energy by 2050.

All of these challenges are amplified by the fact that several other jurisdictions across the PJM region have made similarly strong commitments to clean energy including Washington DC at 100% renewables by 2032, Maryland at 50% renewable by 2040, Delaware at 40% renewable by 2035, Virginia at 100% renewable by 2045/2050, and Illinois considering 100% clean energy as early as 2030.[31]

The 2019 MOPR ruling initiated extensive rehearing requests and compliance filings. As a result, there have been significant delays to the PJM capacity auction schedule; the planning year 2022/23 auction that was originally scheduled for spring 2019 was rescheduled for mid-2021.[32] Auctions for the subsequent planning years will be conducted on a compressed schedule approximately every six months until the market resumes its normal schedule with a May 2024 auction for the delivery year 2027/28.

31 *See* PJM-EIS "Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States," and "What is the Clean Energy Jobs Act," Illinois Citizens Utility Board.

32 *See* the PJM capacity market schedule in Pete Langbein, "Update on Base Residual Auction Schedule," PJM Interconnection, L.L.C., November 19, 2020.

In parallel, there are continued efforts to eliminate the MOPR through other avenues. The composition and leadership of the FERC has recently changed significantly and now appears likely to require PJM to eliminate MOPR prior to the December 2021 auction (for delivery year 2023/24).[33] PJM itself has identified the current MOPR as an "unsustainable" rule that will need to be reformed (and largely eliminated) under an expedited process prior to the December 2021 auction.[34] Beyond FERC and PJM efforts, the U.S. Court of Appeals for the Seventh Circuit is set to begin hearings on appeals to the MOPR expansion early in 2021 with the possibility of ruling as soon as late 2021.[35] The elimination or reform of the MOPR is not guaranteed and will require continued focus from New Jersey policymakers and Board Staff. However, the outlook for a positive resolution, including repeal or substantial reduction of the MOPR, is far superior as compared to the outlook when the Board initiated the resource adequacy investigation in May 2020.

B. Scale of Policy Resources Affected

The 2019 MOPR amendments ordered by FERC expressly imposes an offer price floor on state policy-supported resources, which in some cases may impede their ability to sell capacity in the PJM capacity market. However, not all of New Jersey's clean energy resources would be excluded from clearing RPM by the 2019 MOPR. Most important, Staff does not see the 2019 MOPR as affecting the ability of nuclear units receiving ZECs to clear in the PJM capacity auction. While the nuclear units are technically subject to MOPR in the May 2021 Base Residual Auction, the 2019 MOPR allows the nuclear units to offer into the market at a MOPR floor price of $0/MW-day. Thus, MOPR has no effect on the nuclear units. Further, existing renewables resources that previously received public policy support under RPS and cleared the RPM or signed interconnection agreements prior to the December 2019 order are categorically exempt from MOPR. Likewise, resources that do not participate in the capacity market (*i.e.*, net-metered solar) do not receive capacity market revenues and are therefore not impacted by MOPR. Finally, resources have the opportunity to seek a unit-specific MOPR price that is lower than the PJM default MOPR floor price, which could enable some policy resources to clear the market even if they are subject to the expanded MOPR.[36]

Figure 9 summarizes the outlook for New Jersey policy resources that will be subject to MOPR if the current rule remains in place. All values in this figure are reported on an unforced capacity (UCAP) basis, which is a best understood as the number of megawatts of capacity consistently provided by a generating facility, after accounting for performance, reliability, and (in the case of renewable resources) variability in performance levels driven by weather. UCAP is thus an appropriate metric for determining a given resource's contribution to the resource adequacy of the electric grid and the one typically used in

[33] *See* Catherine Morehouse, "FERC open to revisiting MOPR, as grid operators, utilities mull future of wholesale markets," *Utility* Dive, March 24, 2021; and Catherine Morehouse, "Glick: FERC should tackle MOPR if PJM can't agree on update by December capacity auction," *Utility Dive,* April 13, 2021.

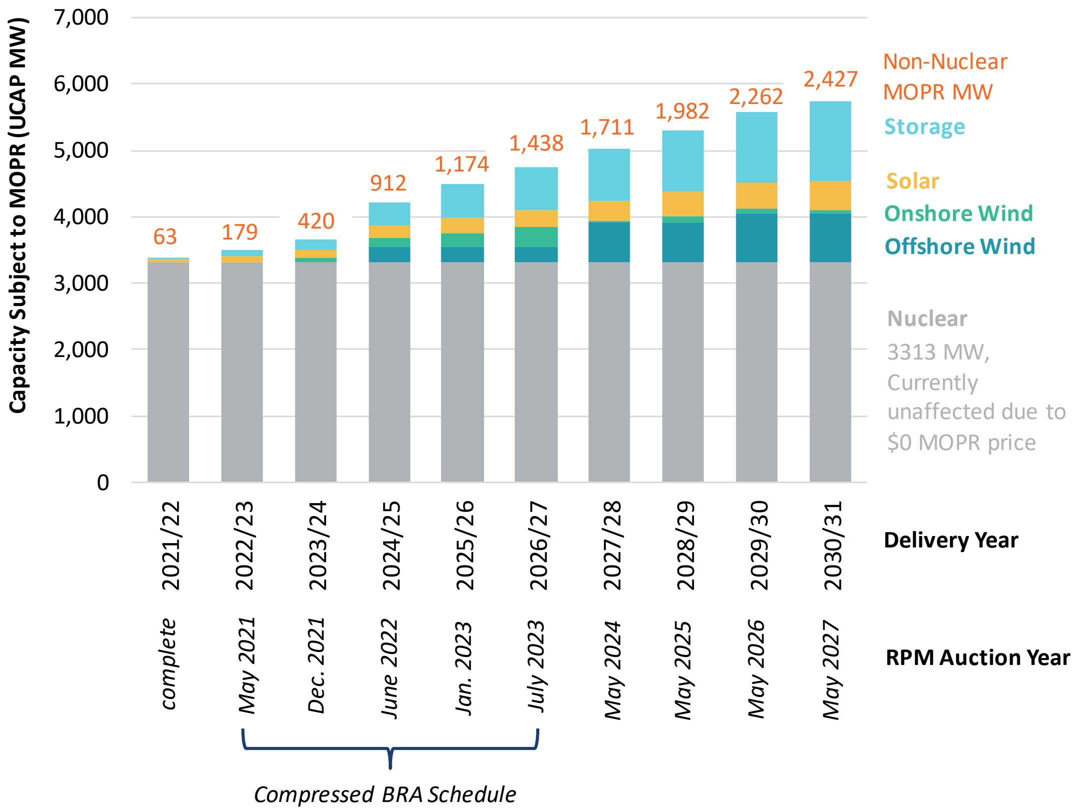
[34] PJM Interconnection, L.L.C., "Technical Conference on Resource Adequacy in the Evolving Electricity Sector: Statement of PJM Interconnection," March 21, 2021.

[35] *See* additional discussion of the status and outlook for the 2019 MOPR from Jeff Dennis, "MOPR and More: Where the Minimum Offer Price Rule and Related Measures Stand Going Into 2021," *Advanced Energy Economy*, December 16, 2020.

[36] The analysis of MOPR presented in this report assumes that resources will offer at the default MOPR price, as adjusted for realistic technology cost declines over the relevant timeframe. Cost impacts could be lower if some resources are enabled to clear the market through unit-specific exemptions, or higher if more resources would fail to clear due to higher MOPR prices in the future, particularly for nuclear resources.

electricity markets nationwide, including in PJM.[37] In general, the impact of MOPR is modest in the early years and grows with time. In particular, new resources procured to meet New Jersey's ambitious offshore wind goals, new solar program targets, storage targets and the growing RPS, among others, will generally be swept up into MOPR and forced to offer their capacity at artificially high prices. Unless FERC reverses course, the capacity subject to a MOPR price floor could grow to approximately 1,200 UCAP MW by 2025 and 2,400 UCAP MW by 2030. Those numbers could grow further to 4,500 UCAP MW by 2025 and approximately 5,700 UCAP MW by 2030 if nuclear resources are meaningfully affected by MOPR in future auctions.

FIGURE 9: NEW JERSEY POLICY RESOURCES AT RISK OF NOT CLEARING BECAUSE OF MOPR



Sources and Notes: Nuclear capacity based on UCAP rating in 2021/22 offers. Offshore wind capacity based on New Jersey solicitation schedule; assuming 1,800 MW procured for 2027 and 600 MW procured for 2029. *See* "Governor Murphy Announces Offshore Wind Solicitation Schedule of 7,500 MW through 2035," Office of the Governor of the State of New Jersey press release, February 28, 2020. Assuming an additional 250 ICAP MW of solar per year. Out-of-state wind calculated as balance in capacity required to meet New Jersey's RPS goals. Storage capacity based on N.J. Stat. § 48:3-87.8(d), approved May 23, 2018; assuming the 600 ICAP MW target is not met until 2022 and a linear increase to 2,000 ICAP MW in 2030. Revised BRA schedule obtained from Pete Langbein, "Update on Base Residual Auction schedule," November 19, 2020, p. 2.

The total quantity of resources subject to the expanded MOPR PJM-wide could be approximately 8,100 UCAP MW by 2025 and 11,500 UCAP MW by 2030. The majority of these resources are multi-unit nuclear plants earning ZECs and able to offer at zero MOPR price and thus unless the MOPR floor price changes, would be unaffected by the expanded MOPR. However, given current MOPR price levels (and after

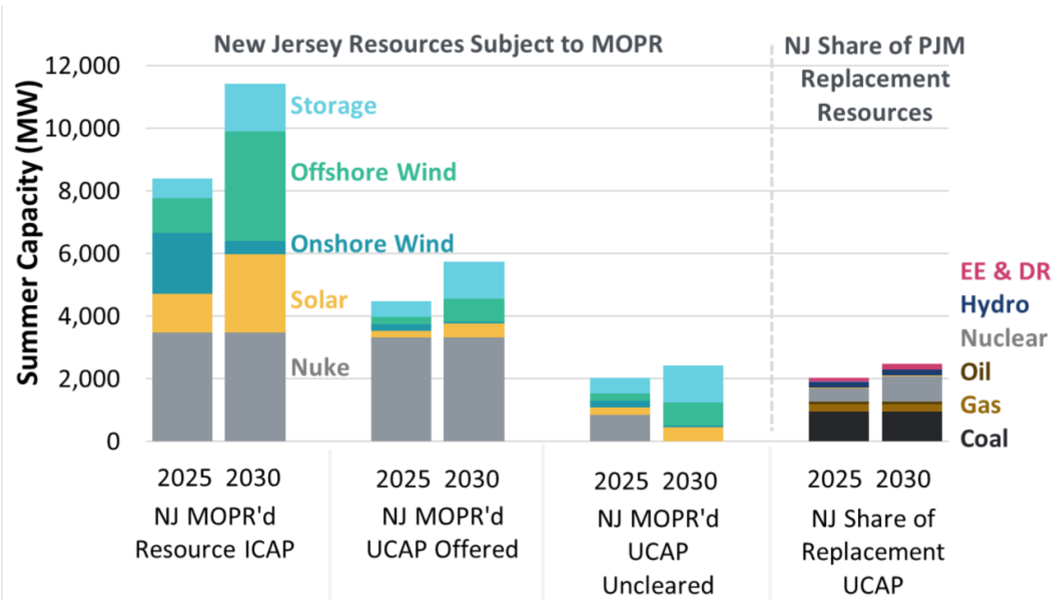
[37] The UCAP value of these facilities is small than the total "installed capacity" of the policy resources (i.e., their ICAP rating). So while New Jersey policies typically speak in terms of installed capacity, the PJM capacity market recognizes only a percentage of a facility's ICAP value. This is because the "unforced capacity" or UCAP value renewable or capacity resources for capacity market purposes is only a fraction of their ICAP ratings. The number of UCAP megawatts affected by the 2019 MOPR is further reduced because a significant share of anticipated clean energy resources are exempt from MOPR for other reasons.

adjusting for projected resource cost declines), new onshore wind, offshore wind, solar, and storage resources are unlikely to clear at default MOPR floor prices. Thus, on a PJM-wide basis we find that approximately 3,500 UCAP MW of policy resources are at risk of not clearing by 2025, and up to 6,800 UCAP MW by 2030.[38]

C. Impacts on Resource Mix and Customer Cost

In New Jersey, the expanded MOPR will likely prevent all renewable resources subject to the MOPR from clearing, while all nuclear resources' offer prices would be unaffected due to the $0/MW-day offer floor. Figure 10: New Jersey Contracted capacity Subject to MOPR and Replacement Capacity illustrates the contracted renewable resources subject to MOPR in New Jersey in 2025 and 2030 and the market response to replace the uncleared capacity. Our analysis indicates that fossil resources are likely to replace approximately 60% of the uncleared policy resources contracted to New Jersey in 2025, and 50% in 2030. Absent the expanded MOPR, these aging fossil resources would be likely to permanently retire.

FIGURE 10: NEW JERSEY CONTRACTED CAPACITY SUBJECT TO MOPR AND REPLACEMENT CAPACITY



Sources and Notes: "NJ Share of Replacement UCAP" summarizes the replacement capacity resources that are uncleared under a No MOPR scenario that do clear under MOPR. It reflects New Jersey's share of the incremental PJM-wide cleared capacity, calculated as the fraction of New Jersey uncleared MW divided by PJM-wide uncleared MW.

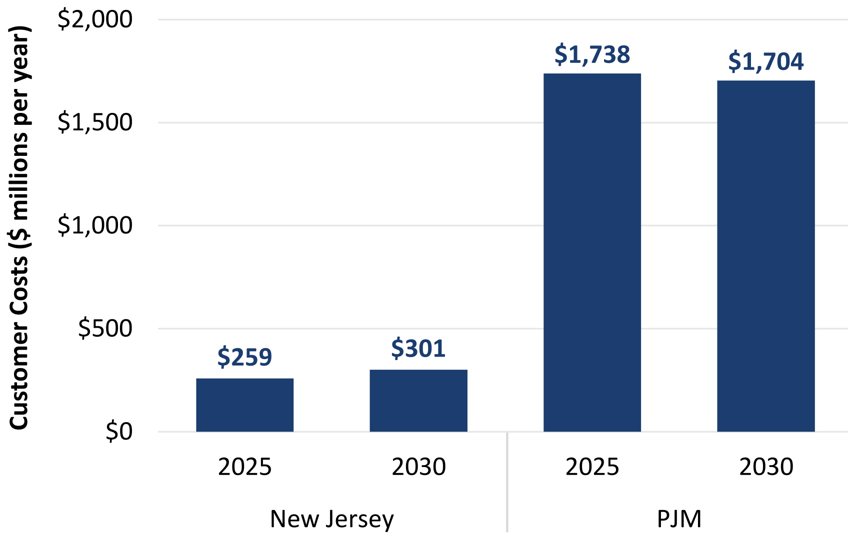
The application of MOPR to policy resources will subject New Jersey customers to approximately $260-300 million per year in excess costs as summarized in Figure 11.[39] On a PJM-wide basis, the expanded

[38] Outlook developed based on an analysis of individual states' policy goals, existing resource mix, resource ratings, current MOPR price levels, and the outlook for resource cost declines. "2022/2023 BRA Default MOPR Floor Offer Prices for New Entry Capacity Resources with State Subsidy," PJM Interconnection, L.L.C. and "2020 Annual Technology Baseline," National Renewable Energy Laboratory. The volume of resources subject to MOPR in New Jersey and PJM-wide differ from the estimates presented in the March 19, 2021 work session within the BPU resource adequacy investigation based on updates to remove the Ohio nuclear resources that will no longer earn ZEC support and updates to estimated ELCC values for battery storage and renewable resources.

[39] The Brattle model of the PJM RPM in 2025 reflects confidential supply offer data from the 2021/22 auction, adjusted for expected retirements and new entry. For 2030, we use a synthetic supply curve based on public data and estimate the long-run average avoidable net going forward costs of supplying capacity; this 2030 supply curve is more elastic, yielding relatively lower price impacts of MOPR for the same quantity of capacity excluded by MOPR.

MOPR would cost approximately $1,700 million per year in excess costs. As discussed above, the application of MOPR to policy resources leads to higher capacity prices because policy resources excluded by MOPR are replaced by more expensive resources, and fewer resources clear the capacity market overall (producing higher prices and lower quantities on the PJM demand curve). We estimate that average capacity prices paid by New Jersey consumers would include a MOPR-driven premium of $26/MW-day in 2025 and $25/MW-day in 2030. These estimates are consistent with or on the lower end of price impacts of expanded MOPR presented in other studies.[40] In addition, a double payment occurs because customers are paying for capacity through the capacity market and again for renewable capacity under the New Jersey RPS, further increasing the costs of the expanded MOPR.

FIGURE 11: CUSTOMER COSTS IMPOSED BY MOPR



III. Fixed Resource Requirement

One potential path available in the pursuit of ensuring state policy resources serve as New Jersey capacity, notwithstanding application of the MOPR, is for the State to elect the FRR alternative. Under the FRR alternative, New Jersey would be responsible for procuring its own capacity supply mix and utilize its own chosen approach to meeting the State's resource adequacy needs. This election is required for a minimum of five consecutive years. Procured resources would be submitted to PJM as the State's FRR plan for meeting total and locational capacity requirements. The FRR alternative is not a single design option, but instead an open-ended opportunity for New Jersey to determine any and all features of how capacity needs could be met, within the parameters of the PJM Governing Documents. The open-ended nature of the FRR alternative is an opportunity and a challenge in that the state would need to develop its own, new approach to meeting resource adequacy needs and mitigate the myriad attendant risks.

Numerous commenters have proposed options for how the FRR alternative could be designed and implemented in New Jersey and Staff particularly wishes to thank those commenters for their deeply thoughtful and well-researched positions. These options were described in a series of commenter filings

40 For example, in MOPR/FRR Sensitivity Analyses of the 2021/22 RPM Base Residual Auction, the IMM estimated a $25-$234/MW-day cost reduction from FRR application to various quantities of supply subject to MOPR and other design structures. In a dissent to the December 19, 2019 FERC Order which expanded the scope of MOPR to renewable sources, Commissioner Richard Glick stated a $40/MW-day price impact due to MOPR. In a webinar, ICF estimated $25-35/MW-day short term, $30-50/MW-day mid-term, and $50-70/MW-day long-term price effects due to implementation of MOPR with no additional FRR.

and presented in a Technical Session held on September 18, 2020, and a dedicated Work Session held on November 9, 2020.[41] The FRR alternatives investigated most fully included:

- *Contracting-based FRR approaches* in which a state agency or utility would engage in long-term contracting with clean energy resources that serve the dual purposes of meeting state policy goals and securing capacity that would be utilized under the FRR plan;
- *New Jersey state-wide FRR auctions* in which a state agency or utility would begin the state FRR plan by utilizing the UCAP capacity value of any MOPR'd resources that the state already holds title to, and meet any remaining capacity needs through a competitive single-state capacity auction to meet the FRR plan requirements;
- *Partial state FRR auctions covering only one utility area,* in which a portion of the state would be selected to utilize an FRR plan that would be large enough to utilize all of New Jersey contracted MOPR resources, requiring a smaller residual share of the FRR plan capacity requirements to be procured via competitive auction; and
- *Utilizing the FRR construct to implement the ICCM or similar clean capacity market,* which is more fully addressed in Section IV below.

This report does not opine on whether these FRR reforms would be consistent with current law and statutory authorities, but has instead focuses on conducting a review of the economic merits and practical considerations involved in implementing each approach with the understanding that implementation of any one of these options would involve a number of complicated legal questions. All three approaches share some of the same substantial implementation challenges such as the need to designate an FRR entity, authorize and fund the FRR entity, develop procurement mechanisms, and each approach introduces various implementation risks. Staff identified the contracting-based approach as generally less attractive given the greater complexity, reliance on administrative judgement, increased risks to consumers, and conflict with New Jersey's policy to rely on market-based approaches. The two capacity auction-based approaches offer the advantage of being the most straightforward means of implementing FRR and maintaining a competitive format, but still pose serious implementation risks, including the potential for generator owners to exercise market power, thus driving up prices to non-competitive levels. These simplest auction-based approaches could help to mitigate MOPR-related costs, but do nothing to address the more fundamental disconnects between the capacity market and New Jersey's clean energy mandates, or make progress toward a sustainable regional market design.

Overall, if MOPR is not eliminated from the broader RPM capacity market in a timely fashion, then an auction-based, single-zone FRR could be pursued further to determine whether it is a viable option to reduce the impacts from the expanded MOPR. Serious implementation risks have been raised by commenters, and any future evaluation or implementation of the FRR alternative must carefully consider all risks to New Jersey customers. However, if the expanded MOPR is eliminated from the broader PJM market, these capacity-only, MOPR-focused FRR options would retain these same risks with substantially less benefit. These options may become more attractive if regional or federal regulators stand in opposition to New Jersey's clean energy objectives. Under a no-MOPR RPM scenario, the primary rationale for pursuing an FRR would be as a vehicle for New Jersey, and possibly other states, to pursue a state-driven clean capacity market as discussed further in Section IV below.

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41 *See* State of New Jersey Board of Public Utilities Technical Conference Agenda for September 18, 2020 and First Work Session Notice for November 9, 2020.

A. The FRR Alternative

Since its inception, the RPM has included provisions for the FRR alternative that can be utilized by any qualified entities that wish to procure capacity outside the PJM capacity market on behalf of their customers. The FRR was originally designed to fit the needs of vertically integrated utilities that conduct resource planning and that do not wish to have uncertainty in the quantity of capacity requirements that can be produced by the sloped demand curve.[42]

Though not originally intended for this purpose, New Jersey could elect to exercise the FRR alternative to limit the impact of the expanded MOPR on New Jersey policy resources. The FRR construct requires that sufficient capacity resources be procured to meet total and location-specific capacity requirements to meet local peak load plus a required capacity reserve margin. The PJM requirements under FRR remain agnostic as to how the resources are procured or at what price. This mechanism would allow New Jersey to select its own mix of capacity resources without regard to the application of MOPR.

Eligible FRR entities interested in electing the FRR alternative for the first time must notify PJM at least four months before the BRA for the first delivery year the FRR alternative will be in effect.[43] Given the currently compressed PJM auction schedule, the deadlines for FRR election are similarly compressed and accelerated. To initiate FRR beginning with the 2024/25, 2025/26, or 2026/27 delivery year would require formal election of the FRR alternative by February 2022, September 2022, or March 2023 respectively.[44] The election for the FRR alternative requires a commitment of a minimum of five consecutive delivery years. However, FRR elections can be terminated early based on the following conditions:

- PJM establishes a separate VRR curve for an LDA encompassing the FRR service area.
- A state regulatory “structural change,” such as the transition to a competitive retail market.

If choosing an FRR alternative, an “FRR entity” must take responsibility for securing capacity commitments on behalf of the designated customers. Table 1 summarizes the FRR obligations for the LDAs that would be relevant for a New Jersey FRR plan in the 2022/23 delivery year. A New Jersey-wide FRR would need to procure approximately 20,000 UCAP MW of capacity (second to last row), of which a minimum share must be located within each of the relevant LDAs (last row). Note that the nested LDA structure means that the locational requirements are not additive. For example, any capacity within the PS North LDA would contribute toward meeting the PS North, PSEG, EMAAC, MAAC, and New-Jersey-wide capacity obligations.

The FRR entity must submit an FRR plan to PJM three years in advance of delivery (and at least four months in advance of the RPM auction) to identify the specific resources committed to serving customers. If any of the identified resources would fail to fulfill its delivery obligation or incur performance penalties, the associated penalties would be assessed to the FRR entity.[45] If insufficient resources are committed under the FRR plan for a particular day (e.g. because the resource fails to come online), the FRR entity would be subject to a deficiency change equal to 1.2 times the locational capacity market price that would have applied in the auctions. In addition, the FRR entity would need to select whether to utilize a physical or financial non-performance approach to addressing obligations under capacity performance rules, under

[42] *See* Section 11, PJM Manual 18: PJM Capacity Market and Comments of PJM within the New Jersey BPU Staff Investigation of Resource Adequacy Alternatives.

[43] For additional discussion of FRR rules and procedures, *see* Schedule 8.1 in “Reliability Assurance Agreement among Load Serving Entities in the PJM Region,” PJM Interconnection, accessed May 7, 2021.

[44] *See* PJM Capacity Market Auction Schedule.

[45] Sections 11.8 and 11.9 of PJM Manual 18: PJM Capacity Market, January 27, 2021.

which the FRR entity would take responsibility for the performance of all individual resources committed under the FRR plan. Any FRR approach pursued would need to clearly define and distribute risk of underperformance, to avoid negative reliability outcomes and downside performance risk remaining with New Jersey ratepayers.

In addition, a recent dispute has been raised as to whether an initial FRR plan requires only a one-year resource commitment, or a commitment for the full five-year minimum FRR term.[46] The outcome of this dispute will bear on any future evaluation of the FRR Alternative, as a requirement for a minimum five-term commitment of capacity resources would require substantial additional considerations related to risk mitigation and procurement strategies in any of the FRR Design Options listed below.

TABLE 1: NEW JERSEY LDA FRR OBLIGATIONS AND RESOURCE REQUIREMENTS (2022/23 DELIVERY YEAR)

			RTO	MAAC	EMAAC	PSEG	PS-North
Total LDA							
Coincident Peak Load	*(MW)*	[1]	152,505	55,042	29,914	9,392	4,874
Forecast Pool Requirement	*(%)*	[2]	108.9%	n/a	n/a	n/a	n/a
CETL	*(UCAP MW)*	[3]	n/a	2,252	9,752	7,445	3,777
Reliability Requirement	*(UCAP MW)*	[4]	166,032	65,149	36,302	11,557	6,131
Price Responsive Demand	*(UCAP MW)*	[5]	425	425	65	0	0
EE Addback	*(UCAP MW)*	[6]	3,913	1,345	937	379	89
FRR Obligations							
Min Internal Resource Requirement	*(%)*	[7]	n/a	100.0%	81.5%	40.2%	44.4%
Reliability Req Adjusted for FRR	*(UCAP MW)*	[8]	152,993	65,149	36,302	11,557	6,131
New Jersey Portion of LDA							
Coincident Peak Load	*(MW)*	[9]	17,714	17,714	17,714	9,392	4,874
New Jersey % of Coincident Peak Load	*(%)*	[10]	11.6%	32.2%	59.2%	100.0%	100.0%
Price Responsive Demand	*(UCAP MW)*	[11]	0	0	0	0	0
EE Addback	*(UCAP MW)*	[12]	605	605	605	379	89
FRR Obligations							
FRR Entity UCAP Obligations	*(UCAP MW)*	[13]	**19,890**	19,890	19,890	10,604	5,396
Min Internal Resource Requirement	*(UCAP MW)*	[14]	n/a	**19,890**	**16,210**	**4,263**	**2,396**

Sources and Notes:
[1] - [5], [8], [9] – [10]: 2022/2023 RPM Base Residual Auction Planning Parameters
[6]: Not available for 2022/23 at the time of publication, adopted PJM 2021/2022 RPM Base Residual Auction Planning Parameters, adjusted for forecasted growth in peak load.
[7]: Minimum of 100% and ([4] – [3]) / ([1] x [2]).
[9] = [1] for PSEG and PS-North; EMAAC obtained as sum of PSEG, JCPL, AECO, and RECO peak load from 2022/2023 RPM Base Residual Auction Planning Parameters; MAAC = EMAAC; RTO = MAAC.
[10] = [9] / [1].
[11]: No price responsive demand in New Jersey. *See* James McAnany, "2020 Demand Response Operations – Markets Activity Report: December 2020," PJM Interconnection, L.L.C, December 7, 2020, Figure 1.
[12] = [10] x [6] for PSEG and PS-North; EMAAC = PSEG + New Jersey share of non-PSEG EE Addback in EMAAC; MAAC = EMAAC; RTO = MAAC.
[13] = ([9] – [11]) x [2] + [12].
[14] = [13] x [7].

[46] See complaint filed by LS Power before the FERC on May 7, 2021, Docket No. EL21-72.

B. Structural Competitiveness of New Jersey Capacity Supply

Several commenters and the PJM Independent Market Monitor (IMM)[47] have expressed concern that adopting an FRR would present or exacerbate risks associated with the potential exercise of market power. The findings of this investigation confirm these concerns.

Small sub-regions of capacity markets tend to face challenges with a lack of structural competitiveness. Capacity markets tend to be structurally non-competitive when one or a small number of firms control market share sufficient that they have the incentive and ability to exercise market power. Large LDAs with an excess of capacity will tend to be competitive because more supply is available to meet local needs than the minimum required and so local sellers must compete with imports. An LDA with a more fragmented ownership structure will also be more competitive. However, an LDA with a small quantity of excess supply and a single entity owning most of that supply is structurally uncompetitive. In that circumstance, a single seller could engage in economic or physical withholding, drive up local prices, and earn greater revenues on its entire portfolio of local resources.

The smallest LDAs of PS-North and PSEG are both structurally non-competitive and have relatively tight supply-demand balance.[48] The remainder of New Jersey is within the EMAAC LDA which is structurally more competitive, but not sufficiently competitive to ensure that one or more firms would be unable to privately benefit from economic or physical withholding. The lack of structural competitiveness within various RPM sub-regions is a challenge that already exists today in the PJM capacity market, a concern that the IMM regularly comments on and suggests should be addressed.[49]

Given the lack of structural competitiveness of resource adequacy markets generally and the particular situation of the New Jersey region it would be essential for any resource adequacy structure (whether RPM, FRR, or otherwise) to be overseen with a robust monitoring and mitigation framework. The FRR presents new challenges in mitigating this endemic market power, as New Jersey has not previously imposed must-offer, offer cap, or other market monitoring and mitigation measures similar to PJM's approaches under RPM. Any resource adequacy structure considered should also aim to avoid further segmenting the market if doing so would increase market concentration in any submarkets unless there are offsetting benefits that would outweigh the greater exposure to exercise of market power. This structural non-competitiveness requires further review and development of appropriate and robust mitigation measures before any FRR option can be recommended or implemented.

47 Monitoring Analytics is the long-standing IMM for PJM and describes itself as a "fully independent external market monitor for PJM Interconnection … [and is] responsible for promoting a robust, competitive and nondiscriminatory electric power market in PJM by implementing the PJM Market Monitoring Plan."

48 Based on analysis of resource supply, RPM demand parameters, and ownership data obtained from the ABB Energy Velocity suite.

49 For example, *see* Monitoring Analytics, "State of the Market Report for PJM: Volume II, Section 5 – Capacity Market," March 11, 2021, p. 261.

C. FRR Design Options

CONTRACTING-BASED FRR APPROACHES

Early on in the BPU investigation, FRR concepts were offered that would transition New Jersey away from a market-oriented approach to meeting supply needs and toward a system of long-term contracts.[50] The details of these options varied across commenters and offered varying levels of specificity, but shared the general concept that the State would increase its reliance on state-sponsored, multi-year contracts to meet its environmental goals. The capacity value of the contracted resources would then be utilized within an FRR plan submitted to PJM. Residual capacity needs beyond what was fulfilled through clean energy contracts could be procured through one-year capacity-only contracts with other existing supply resources, or could use some means to prioritize clean resources in any residual capacity procurement.

Implementing a contracting-based FRR approach in New Jersey would be a complex task and require the State to designate an FRR entity and authorize it to conduct capacity procurement, with associated costs recovered from customers. The designated FRR entity could be a state agency, the distribution utility, an independent procurement administrator, or some combination. The FRR entity would be selected either state-wide or individually for each distribution utility's service territory and would take responsibility for meeting the capacity needs of customers within that service territory. There are many examples of how such a contracting-based approach could evolve and function. New Jersey already engages in competitive solicitations and long-term contracting with offshore wind developers, and could expand its contracting activities to more resource types. If these administrative contracts were expanded to cover the entire supply mix, the sector may operate similar to Ontario's single-buyer model in which a state agency determines the types of supply needed and contracts with power producers to develop or retain that supply.

Many variations of a contracting-based FRR could be developed, but the general outlines of how a contracting-based FRR could be implemented (given adequate authorities) are as follows:

- A state agency would determine how each existing and anticipated future clean energy contract could be translated into a capacity resource under the FRR plan. Mechanisms would need to be developed to appropriately incorporate existing State-approved contracts for offshore wind, and existing contracts with customers or competitive retailers. The goal would be to ensure that these existing resource arrangements can be translated into capacity commitments under an FRR plan.
- Future needs for clean energy would be met through a new system of multi-year contracts (proposals ranged from five-year commitments consistent with the minimum FRR period to long-term contracts as consistent with resource life). Commenters offered a range of ideas for how the long-term contracts would be selected, prioritized, and priced. The common element of these proposals was that the State could oversee an approach that would be designed to achieve environmental policy mandates, capacity requirements, and other policy goals. All resources contracted under the FRR would be required to submit their environmental attributes to the state agency or FRR entity, and the capacity commitment would be offered to the FRR entity. These capacity commitments would be submitted as part of the FRR plan to PJM (and would not be subject to MOPR).

[50] *See*, for example, "Joint Reply Comments of PSEG and Exelon Generating Company LLC," Public Service Enterprise Group and Exelon Generation, May 20, 2020 and "Initial Comments of Public Interest Organizations Regarding Resource Adequacy Alternatives," Natural Resources Defense Council and Sierra Club, May 20, 2020 submitted in *In the Matter of BPU Investigation of Resource Adequacy Alternatives*, State of New Jersey Board of Public Utilities Docket No. EO20030203.

- The contracted resources may fulfill only a portion of the total capacity requirements needed, in which case the FRR entity would engage in competitive solicitations to procure any residual capacity needs. This residual procurement could include procurement from the lowest-cost capacity resources (whether fossil or clean) or could prioritize procurement of clean capacity resources.
- Contracted supply resources (whether under long-term contract or one-year commitments) would make a capacity commitment to the FRR entity up to the quantity that they are qualified to contribute under PJM's capacity accounting mechanisms. The FRR entity would be obligated to pay the seller for these capacity commitments at the agreed-upon price; the resource would be obligated to perform under PJM's capacity obligations.
- The FRR entity would take responsibility for all settlements with PJM under the FERC Tariff. Any non-delivery or performance penalties caused by resources under an FRR commitment would be charged to the FRR entity (and likely should then be passed back as an assessment to the individual resource creating the penalty liability).[51]
- The FRR entity would likely need to be compensated for conducting the resource planning, procurement, settlement functions, and managing penalty risks, including compensation for the risks and costs associated with any bilateral contracts and would seek to earn an approved rate of return on any required resource investments.
- Costs associated with capacity procurements and FRR entity compensation would be passed on to all end-use customers as non-bypassable charges.

The contracting-based FRR approaches discussed by commenters in this investigation offer a wide range of alternative approaches that would need to be further developed, vetted, and approved before recommendation. Namely, future evaluation would need to include: how to determine the contract term; procurement mechanisms; unbundled or all-in bundled nature of contracts for each resource type; if using bundled contracts, how to fairly value the contributions of resources with very different energy, capacity, and attribute volumes; whether and how to express preferences for clean over fossil resources, how to set payment levels; and how much discretion would be afforded to the FRR entity versus submitted for regulatory approval.

If pursued widely or for many more resources, the contracting-based FRR approach would mark a significant and substantially risky departure from current state policies that are designed to rely on competitive forces within the wholesale market to drive efficient supply-side resource investments and enable competitive retail providers to serve end use customers. Instead, the FRR entity would take on many of the responsibilities that are currently left to individual market participants reacting to price incentives. Compared to current approaches, the contracting-based FRR would create greater ability to reflect a wide range of non-price policy objectives within the resource plan, but would risk reliance on the technical ability of the FRR entity to engage in efficient planning and contracting. The FRR entity would need to be identified (or created), authorized, and funded, and would be vested with a more complex task with greater financial consequences than under other FRR options considered. This approach would place greater reliance on state agencies to develop effective oversight, and offer fewer opportunities to utilize regional competition and market mitigation to achieve competitive prices for New Jersey ratepayers. To the extent that the resource plan is implemented through longer-term contracts or bundled contracts, this would shift risks away from electricity producers and toward customers. Both sellers and customers would enjoy more pricing stability and access to lower-cost financing under such an approach, but the costs of any uneconomic planning or contracting decisions would be borne solely by customers. Overall,

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51 Penalties could arise, for example, if resources retire early, have a delayed online date, fail to output their committed capacity during a routine test, face a capacity de-rate under PJM accounting, or perform poorly during emergency events.

a contracting-based FRR would be a shift away from markets and toward a regulated planning model, in contravention of the Board's long-held positions in support of regional market competition.

NEW JERSEY STATE-WIDE FRR AUCTIONS

Other commenters developed auction-based options for implementing a New Jersey FRR plan that could be developed on a state-wide basis (or within an individual utility zone, as described below).[52] An auction-based approach to implementing an FRR would have some similarities with the contracting-based approach described above but would utilize a competitive auction format to procure the quantity of capacity needed. The approaches considered here assume that the five-year FRR term could be fulfilled via individual one-year commitments procured via auctions.[53] The auction-based FRR would be implemented as follows:

- Each year the FRR entity would publish the parameters of a capacity procurement auction, clarifying the quantity of capacity that it would seek to procure on behalf of New Jersey customers including the minimum share of total capacity that would need to be procured within each applicable LDA.
- As under the contracting-based FRR, a portion of the FRR plan would be met by resources otherwise subject to the MOPR that are contracted on behalf of New Jersey customers; contracted offshore wind resources would be an example of resources that might be automatically incorporated into the state FRR plan. The investigation did not evaluate the terms of existing contracts to evaluate which policy resources can be required to make such commitments under the FRR plan, but generally assumes that future contracts could be structured to require participation.
- The FRR entity would conduct a competitive auction to procure the remaining needed capacity from any PJM-qualified capacity resource in the relevant LDAs. The FRR auction could include maximum limits on the amount of fossil capacity purchased, or alternatively, require that a certain minimum share of capacity be procured from clean resources. Policy resources excluded by expanded MOPR would likely offer into the FRR auction at a low price given that they would be unlikely to earn capacity payments by selling into PJM's RPM auction. Other capacity resources without market power should rationally offer at prices near the expected price in the upcoming RPM auction (reflecting the opportunity cost of not selling into the PJM market).[54] If any entities would have structural market power, it may be possible to exercise through physical or economic withholding within the FRR auction unless sufficient monitoring and mitigation measures are in place.
- The FRR procurement auction could take a variety of forms, the simplest of which would be a single round, uniform price auction. However, Staff would suggest that any FRR auction would procure at least two prices, one for generic fossil capacity and another for clean capacity. The State could determine a price at which it would select the clean resource over a less expensive fossil resource.

[52] *See*, for example, "Post-Technical Conference Comments of PSEG," October 2, 2020, submitted in *In the Matter of BPU Investigation of Resource Adequacy Alternatives*, State of New Jersey Board of Public Utilities Docket No. EO20030203; "BPU Resource Adequacy Investigation: FRR Discussion," November 9, 2020; and "Jersey Central Power & Light Company Post-Work Session Comments," November 23, 2020, submitted in *In the Matter of BPU Investigation of Resource Adequacy Alternatives*, State of New Jersey Board of Public Utilities Docket No. EO20030203.

[53] A pending complaint before FERC submitted by LS Power suggests that FRR plans should instead include multi-year commitments from resources; the Staff investigation assumes the previously-existing status quo that no multi-year commitments will be required under any FRR. A multi-year commitment requirement would be a substantial change that may pose significant additional challenges to implementing an FRR plan.

[54] *See* additional discussion of how RPM opportunity costs would affect FRR participation in "Jersey Central Power & Light Company Post-Work Session Comments," November 23, 2020, submitted in *In the Matter of Investigation of Resource Adequacy Alternatives*, State of New Jersey Board of Public Utilities Docket No. EO20030203.

- To ensure adequate procurement within the import-constrained subregions, the auction would need to be structured so as to enable higher prices in the import-constrained subregions. Considering the FRR parameters prevailing in recent years (see above), the majority of New Jersey capacity supply under FRR would be priced consistent with the EMAAC LDA; very modest volumes from the broader MAAC LDA would be possible to utilize at potentially lower prices; and no volumes would be possible to utilize at lowest RTO prices.[55] The most import-constrained areas of PSEG and PS-North would potentially clear at higher prices. These import-constrained areas have a relatively tight supply-demand balance and have highly concentrated supply ownership.
- The FRR entity would make a payment commitment consistent with the procurement auction to the cleared capacity resources and submit these cleared resources to PJM within the FRR plan (which must be submitted approximately one month prior to the broader PJM auction). Any capacity resources that fail to clear the New Jersey FRR auction would be able to offer their capacity into the subsequent BRA.
- Any shortfalls in procured volumes through the FRR or resource non-delivery of the FRR would result in FRR shortfall penalties at a rate of 1.2 times the relevant RPM price; poor resource performance could incur additional performance penalties. The FRR entity would interact directly with PJM for the purposes of any penalty settlements, passing any associated costs on to the individual resources (or to customers, e.g. if the FRR plan had insufficient resource commitments).

Similar to the contracting-based FRR, the auction-based approach would create an opportunity to enable resources contracted for policy purposes, and subject to the expanded MOPR, to provide capacity within the PJM footprint. This applies whether the policy resource is contracted on behalf of New Jersey's customers or those of other states. The auction-based approach would not offer the same level of competitive benefits as participation in the broad RPM market, but would retain some of these benefits due to the reliance on a competitive auction format with transparent demand parameters, auction format, unbundled one-year capacity contracts, and transparent pricing. Oversight and compensation of the FRR entity would be far less challenging than under a contracting-based FRR given that the auction procedures would be strictly delineated and approved by state authorities (minimizing the role of administrative judgement or misaligned incentives in resource selection).

However, the New Jersey-wide FRR auction poses implementation challenges that could make it less attractive as a permanent resource adequacy structure. New Jersey is a relatively small share of the PJM market, with demand requirements that must be met for each successively more import-constrained LDA (MAAC, EMAAC, PSEG, and PS-North). The most import-constrained areas, PSEG and PS-North, are highly concentrated. The broader EMAAC area serving the majority of the state is more structurally competitive, but not so competitive that market forces alone can be relied upon to mitigate the potential for the exercise of market power. These challenges raise the concern that there could be a lack of competition or the exercise of market power within a New Jersey FRR auction. Competition issues would be even more pronounced if the State were to implement a clean capacity constraint in the FRR auction and limit supply participation to in-state resources, given the even more concentrated market for carbon-free capacity, which is dominated by nuclear resources in New Jersey. Market monitoring and mitigation would be more feasible in an auction format than in a contracting-based approach, but would pose particular complexities due to the need to allow offers reflective of the opportunity cost of not participating in the RPM auction and a lack of any pre-existing mitigation mechanisms overseen by New Jersey.

[55] In the RPM auction, New Jersey is able to utilize a small portion of supply from the RTO region consistent with its pro-rata share of import capability, or CETL, into the MAAC LDA. Within the FRR construct, New Jersey is not able to utilize any supply from the unconstrained RTO region due to a nuance of how regional FRR obligations are calculated (namely, the CETL into MAAC is small enough that it becomes zeroed-out relative to the internal MAAC resource requirements).

The state-wide FRR would also require New Jersey to determine whether to maintain a sloping demand curve for capacity within the various LDAs. The elimination of the sloping capacity demand curve could save some costs in the short term by reducing capacity over-supply, but would expose New Jersey to the challenges of a vertical demand curve if maintained over a longer time period. Particularly in the smallest LDAs, the vertical demand curve in New Jersey could produce higher price volatility, greater exposure to locational reliability shortfalls (or associated FRR penalties), and greater exposure to exercise of market power. Overall over the long term, the higher price volatility would produce a less attractive investment climate and so may produce less favorable outcomes over the long term as new resources are needed or existing resources need reinvestment to continue operating; PSEG and PS North are most likely to face these small-market challenges in the near term (though other areas of New Jersey could face these issues as well in the future, particularly if new LDAs are identified and must be modeled within the RPM).

PARTIAL STATE FRR AUCTIONS

To circumvent the most significant challenges of an auction-based FRR approach in the small LDAs of PSEG and PS-North, some commenters have recommended focusing on a partial state FRR auction. The mechanics of a partial-state FRR would be identical to those described above for a full-state FRR, but the geographic scope would be limited to one utility area. Under a partial state FRR:

- A state agency would project the volume of resources anticipated to be excluded from clearing by the expanded MOPR and that would not otherwise serve as PJM capacity to be procured within the FRR construct. A single utility zone would be designated to select the FRR alternative. Commenters recommended that the JCPL utility zone is a sensible choice given that it is large enough to utilize all New Jersey policy resources that might be excluded by MOPR over the coming five years.[56] Further, JCPL is not within the most import-constrained subregions and so would have access to greater volumes of supply across the EMAAC region (including from outside of New Jersey).
- The competitive FRR auction would proceed as described above, procuring sufficient resources to satisfy the FRR requirement of the individual utility zone selected.
- If capacity prices realized under the FRR auction are materially different from those borne by customers in other regions of the state, the State would need to adopt appropriate mechanisms to address any resulting cost-shifts (requiring the development of an appropriate regulatory mechanism that does not presently exist). The purpose of the partial-state FRR would be to mitigate expanded MOPR costs for all customers across New Jersey, and so the resulting costs (or benefits) of the FRR auction would be borne by all customers not just those within the designated FRR utility area.[57]

The partial state FRR auction achieves most or all of the benefits of a state-wide FRR auction by ensuring resources subject to the expanded MOPR serve New Jersey as capacity resources, but would require development of a new construct to create reliance on competitive auction-based pricing. This investigation does not fully evaluate that necessary new construct or evaluate the existing Board authority to implement it. The partial state FRR avoids some of the most problematic aspects of the state-wide FRR auction because it does not include the smallest and most highly concentrated capacity LDAs of PSEG and

[56] As illustrated above, we estimate that approximately 5,700 UCAP MW of New Jersey policy resources would be subject to MOPR by 2030 (including ZEC resources). As of the 2022/23 planning year, the JCPL peak load plus forecast pool requirement that would determine total capacity requirements is approximately 6,100 MW. For example, see comments of PSEG and Exelon witness Northbridge Group, pp. 2-3, filed June 24, 2020.

[57] For additional discussion of single-zone FRR options, *see* "Jersey Central Power & Light Company Post-Work Session Comments," November 23, 2020, submitted in *In the Matter of BPU Investigation of Resource Adequacy Alternatives*, State of New Jersey Board of Public Utilities Docket No. EO20030203.

PS North. Other implementation challenges and risks would still remain, such as implementation costs, market monitoring and mitigation, and risks of design flaws, but the scale of downside risks to New Jersey customers from any uneconomic pricing outcomes would be somewhat mitigated due to the smaller volumes procured in the auction.

D. FRR Implementation Choices

Any pursuit of an FRR approach would require the State to make a number of choices regarding how the FRR would be implemented in light of the relevant implementation challenges and assess which approaches will require additional regulatory authorities to implement. Among the choices that need to be further evaluated before the FRR can be implemented may include:

- **How to Best Manage Costs and Achieve Policy Goals (As Relevant Under Contracting-Based Approaches).** Pursuing a contracting-based FRR raises the opportunity as well as the challenges associated with a significant shift away from market-oriented approaches toward expanded regulator-approved contracting. To transition toward a workable system of expanded contracts would require the State to establish enhanced approaches to selecting resources; setting prices; prioritizing amongst clean and fossil capacity; establishing contract structures and terms; and achieving competition in solicitations. New Jersey already has developed such approaches within its OSW contract solicitations, but would need to develop appropriate mechanisms for all other resource types and for any residual capacity procurements. The risks of high costs that could be borne by New Jersey customers are higher under a contracting-based approach than under other alternatives investigated in this docket, raising the necessity of identifying regulatory oversight mechanisms to maintain cost discipline and limit exposure to uneconomic contracting choices.
- **Selection or Creation of the FRR Entity.** The PJM FRR rules align with distribution utility service territories, meaning that the utilities will likely need to have some role in assisting with data requirements and settlements. However, the utilities are not a natural party to make most resource contracting decisions in New Jersey given their affiliate relationships with capacity suppliers and potential contractual counterparties. Another option would be to task a state agency or a third party independent evaluator to select capacity commitments, then possibly transferring the obligations to each separate utility to manage settlements and penalties.
- **Geographic Scope of the FRR Election.** If the primary purpose of the FRR is to ensure that resources subject to the expanded MOPR serve as capacity (and therefore avoid double-payment), then the selection of a single utility area (rather than the entire state) is likely a preferred design choice in order to mitigate implementation risks. To effectuate a partial-state FRR, a specific utility area, such as JCPL, would need to be selected that is large enough to serve this purpose and that has the greatest access to supply. If the FRR aims to achieve broader environmental goals however, the limited geographic scope would make it less attractive.
- **How to Manage Penalty and Under-procurement Risks.** The FRR entity responsible for settlements with PJM will face penalties if the FRR plan has insufficient supply, if any of the FRR resources fail to deliver the promised capacity, or if resources under-perform relative to their capacity obligations. Under full RPM participation, PJM itself uses a system of credit requirements and imposes any penalties directly to individual resources' owners. In a New Jersey FRR, the FRR entity would become responsible for the aggregate performance of all resources submitted under the FRR plan. Specifically related to penalties and bonus payments relevant to performance during system

shortfall events, the FRR plan can be managed under either a financial or quantity-based approach.[58] Under the financial non-performance approach, PJM would assess to the FRR entity any penalties that arise from under-performance of the individual resources in the FRR plan; under the quantity-based non-performance approach the FRR entity could address any performance shortfall by submitting greater capacity volumes in a subsequent capacity year. The contractual means to pass these penalty risks back to the individual resources and to manage the risk of counterparty defaults would need to be developed (as any default on penalty payments would otherwise be passed to New Jersey customers).

- **How to Remunerate the FRR Entity.** The FRR entity or entities would need to be compensated for their administrative activities and for the risks they bear, and the State may be well served by creating a new entity if it were to select the FRR option. These costs including the administration of auctions, implementing settlements, managing penalties and counterparty risks, and the costs of engaging in large volumes of long-term contracts (under the contracting-based approach). The State would need to determine whether a fee-for-service approach is appropriate and whether any incentive-based remuneration would be pursued as a means of achieving cost efficiency on behalf of customers.
- **Monitoring and Mitigation.** At a minimum, any FRR plan should include some means of reviewing market structure, auction competitiveness, and the potential for exercise of market power. An auction-based approach offers greater opportunities to implement effective controls on the exercise of market power, to the extent that a state agency has the authority to implement them. If New Jersey has the authority, it would be beneficial to impose a capacity must-offer requirement and appropriate capacity offer caps on suppliers that may have the incentive and ability to exercise market power, especially the smallest import-constrained LDAs (PSEG and PS North). The offer caps would need to be high enough to reflect all resource net going forward costs (including the expected opportunity cost of not selling capacity into the subsequent RPM auction), introducing additional challenges to robust mitigation.
- **LDA Sloping Demand Curves.** To the extent that the FRR auction would be utilized to support resource adequacy over an investment or reinvestment cycle, a sloping demand curve may benefit the sustainability of the design. Adopting a well-designed curve for the smallest LDAs could provide a more sustainable basis for investments and maintaining locational reliability. For the portions of New Jersey that can be served from resources in EMAAC and MAAC, the interaction with the broader market will provide this price-stabilizing benefit even if New Jersey maintains a vertical demand curve under the FRR auction.[59]
- **RPM-Derivative Pricing.** Most sellers in the FRR auction would likely offer at their opportunity cost of not selling capacity in the subsequent RPM auction. However, sellers will not know the upcoming RPM clearing price and so would have some uncertainty as to the best offer price in the New Jersey FRR. If sellers guess systematically low, New Jersey customers could benefit from a one-off discount to their capacity payments. If sellers guess systematically high (particularly in any constrained sub-LDAs), New Jersey customers may have to pay an uneconomically high price for that one year. Generally, suppliers would wish to avoid this type of risk, and therefore there may be reduced liquidity in a New Jersey-only FRR auction. Alternatively, suppliers may systematically offer only prices significantly above the clearing price anticipated in the relevant BRA. To address these challenges, variations of an "RPM-derivative pricing" approach have been proposed by

58 *See* PJM Interconnection, L.L.C., "FRR Entity Physical Option for Non-Performance Assessment," May 4, 2016.

59 This price stabilizing effect would materialize indirectly through supplier expectations of RPM prices. RPM prices (which are somewhat more stable due to the regional and RTO-wide capacity demand curves) would inform supplier pricing expectations, and would result in FRR auction offer prices that are distributed around that expectation.

commenters.[60] The RPM-derivative pricing approaches would seek to reduce this problem by accepting offer prices expressed either: (a) as a percentage of the subsequent RPM price; or (b) a pre-specified adder above the subsequent RPM price. These options protect customers from uneconomic high prices (but also forgo the possible benefits of low-price FRR outcomes). We note that this concept poses other complexities and challenges that increase implementation and mitigation complexity, particularly as associated with locational price differences and resources that have a minimum absolute payment needed to take a capacity commitment.

E. Advantages and Disadvantages

The alternative approaches for implementing a New Jersey FRR would ensure that New Jersey policy resources can be applied to serve capacity needs, but would offer a range of other advantages and disadvantages as summarized in Table 2 below.

Of these three FRR options, the contracting-based approach is relatively unattractive given the high implementation complexity, the potential for high costs, shifting risks to consumers, and inconsistency with New Jersey's policy to rely on competitive markets. The auction-based FRR approaches, particularly an option that would select a minimum amount of clean capacity resources or a maximum quantity of fossil resources, are preferred over contracting-based approaches. The auction-based FRR options would allow New Jersey to avoid application of the expanded MOPR to policy resources, and (under some design options) offer opportunities to advance New Jersey's preference to rely on clean capacity resources. Auction-based FRR designs also pose implementation challenges and risks including the need to address the potential for exercise of market power. In general, Staff finds that a preferred approach to addressing policy priorities would be to reflect them through the regional RPM marketplace rather than utilizing the FRR construct. However, should promised reforms to the PJM market not materialize, Staff would suggest revisiting an auction-based FRR in the future.

[60] *See* "Jersey Central Power & Light Company Post-Work Session Comments," November 23, 2020, and Public Service Enterprise Group "Post-Technical Conference Comments of PSEG," October 2, 2020, submitted in *In the Matter of BPU Investigation of Resource Adequacy Alternatives*, State of New Jersey Board of Public Utilities Docket No. EO20030203.

TABLE 2: RELATIVE ADVANTAGES OF FRR IMPLEMENTATION ALTERNATIVES

DESIGN	ADVANTAGES	DISADVANTAGES
Long-Term Contracting-Based FRR	• Eliminate MOPR on policy resources & mitigate MOPR cost impacts • Ability to advance environmental and other policy objectives	• Lose competitive market benefits, substantial associated risk of less efficient planning decisions • Reliance on administrative judgement, shift of risk from producers to consumers, misalignment with retail choice, and reduced transparency • Exposure to exercise of market power, and less ability to monitor and mitigate as compared to auction-based approaches • High implementation complexity & risks • Further evaluation required to determine statutory and regulatory authority • 5-year FRR lock-in period
New Jersey State-Wide FRR Auctions	• Eliminate MOPR on policy resources & mitigate MOPR cost impacts • Maintain some partial benefits of competition for procuring unbundled capacity • Ability to advance environmental and other policy objectives (e.g. through minimum clean capacity requirements)	• Lose efficiency benefits of participating in the broad regional PJM capacity market • Small sub-market challenges including exposure to price volatility, exercise of market power, and periodic reliability (especially in PSEG and PS North) • Medium implementation complexity & risks, including market mitigation • Further evaluation required to determine statutory and regulatory authority • 5-year FRR lock-in period
Partial State FRR Auctions	• Eliminate MOPR on policy resources & mitigate MOPR cost impacts • Maintain some partial benefits of competition for procuring unbundled capacity • Maintain RPM participation for the majority of New Jersey capacity needs • Ability to advance environmental and other policy objectives (e.g. through minimum clean capacity requirements)	• Lose some regional market efficiency benefits (but less than under full state FRR) • Face some market power concerns (but less than under a full state FRR) • Medium implementation complexity, including potential in-state capacity cost sharing • Medium downside economic risks • Further evaluation required to determine statutory and regulatory authority • 5-year FRR lock-in period

IV. Integrated Clean Capacity Market

Beyond the near-term issue of avoiding MOPR impacts, the BPU's investigation has focused on the long-term question of how to align the resource adequacy paradigm with New Jersey's clean energy objectives. Eliminating or substantially reforming the expanded MOPR is a necessary first step, but does nothing to more fundamentally align market incentives to attract and retain the *clean* supply mix that will be needed to reliably serve New Jersey customers in a fully decarbonized grid as envisioned in the Energy Master Plan. The Board and commenters alike have discussed in this docket the importance of a more fundamental realignment of the resource adequacy construct to use a market-based approach to meeting reliability and decarbonization objectives.

Toward that end, BPU Staff and consultants developed a new ICCM design concept that could be utilized as the foundation and framework for driving the reliable, clean, and affordable resource mix demanded by New Jersey, other PJM states, and customers across PJM. At the same time, the ICCM was designed to accommodate the diversity of state goals within the broad regional footprint including states that are decarbonizing at different rates, states' preference to use a range of contracting and policy practices, and acknowledging that some states do not wish to pay any premium for carbon-free resources. The ICCM or a similar Forward Clean Energy Market[61] design could be pursued under a New Jersey FRR, a multi-state FRR, or as a PJM-wide replacement to the current capacity market, with risks decreasing and benefits increasing with geographically broader implementation scope.

A preliminary ICCM straw proposal was discussed in the BPU work session on February 19, 2021 and within a PJM workshop on March 12, 2021, and has been updated in the body of this report and within Appendix B based on feedback received from commenters.[62] Other states are considering variations of the ICCM design or similar proposals including Maryland, New England (all states), and New York.[63] The ICCM is not necessarily the only option that could or should be considered by the state of New Jersey and the broader PJM footprint, but is an example of a fundamentally reformed wholesale market that will be needed to drive a reliable, least-cost decarbonization pathway.

This investigation concludes that a competitive, technology-agnostic, forward clean energy market such as the ICCM can help New Jersey affordably achieve its resource adequacy and clean energy objectives at the lowest combined cost. Staff examined both New Jersey-centric and regional options, and concluded that both options can drive affordable investment in clean energy infrastructure. Depending on how states across the PJM footprint would choose to express their policy goals, a regional solution has the greatest ability to reduce the costs of meeting existing clean energy goals; accelerate renewable deployment; retain existing nuclear plants at risk for retirement; accelerate development of clean capacity resources such as demand response and storage; and/or enable customers to meet their own clean energy objectives. Such a marketplace would offer the greatest economic and environmental benefits if implemented across the broadest possible footprint.

Accordingly, New Jersey should seek to achieve the ICCM or a similar solution on a PJM-wide basis as a replacement to RPM. This report recommends that the Board and Board Staff continue to maintain an active leadership role in the development of any capacity market alternative, and advocate for competitive market structures that sufficiently support and efficiently achieve New Jersey's energy policy goals such as the ICCM.

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61 A Forward Clean Energy Market, or FCEM, also involves forward contracting for clean energy resources by a state or group of states and has clean energy and economic outcomes that are almost as positive as an ICCM structure. The main difference is that ICCM allows the market to automatically optimize the ratio of clean energy resources to conventional resources, while an FCEM relies on market participants to self-manage these risks. For ease of discussion, this report largely uses the ICCM terminology, although almost all the same benefits accrue in both market designs.

62 *See* State of New Jersey Board of Public Utilities, "Notice of Work Session: Investigation of Resource Adequacy Alternative (Docket No. EO20030203)," January 21, 2021 and Kathleen Spees, Walter Graf, and Samuel Newell, "Integrated Clean Capacity Market: A Design Option For Aligning Investment Incentives To Achieve Regional Reliability And Clean Energy Mandates," March 12, 2021.

63 *See* Kathleen Spees *et al.*, "Alternative Resource Adequacy Structures for Maryland: Review of the PJM Capacity Market and Options for Enhancing Alignment With Maryland's Clean Electricity Future," March 2021; Kathleen Spees, "The Integrated Clean Capacity Market: A Design Option for New England's Grid Transition," October 1, 2020; and Kathleen Spees, Samuel Newell, and John Imon Pedtke, "Qualitative Analysis of Resource Adequacy Structures for New York," May 19, 2020.

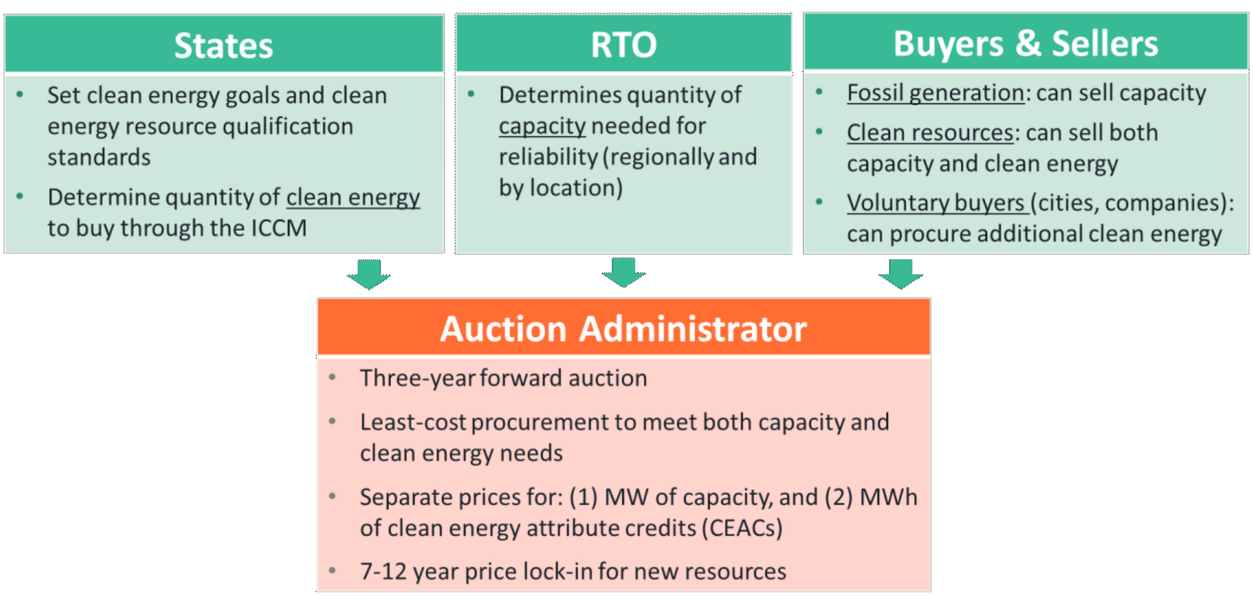
A. Description of the ICCM

The ICCM design could replace the current RPM with a new concept for resource adequacy that aims to achieve not only reliability requirements (as under the current capacity market) but also serve the clean energy demand expressed by states and customers. The ICCM would achieve both of these objectives at the lowest combined cost in a broad regional market place. At a high level, these primary objectives will need to be incorporated into any regional design that is to form the foundation of a sustainable PJM-wide market design that can meet the region's decarbonization requirements.

The ICCM would build on the successful elements of the current PJM capacity market as summarized in Figure 12. The ICCM would be a three-year forward auction to procure two products: (1) capacity in units of UCAP MW as under the current RPM; plus (2) clean energy in MWh of unbundled clean energy attributes. Participating states and voluntary buyers would determine the volume of attributes they wish to procure, their willingness to pay for clean energy, and the specific clean energy attribute product they seek to purchase. The ICCM could accommodate procurement of state-defined RECs, state-defined ZECs, or PJM regionally-defined clean energy attribute credits (CEACs). States could adopt downward-sloping demand curves for clean energy that accelerate decarbonization if the costs of doing so are low, as regulatory structures allow. The costs of procuring the clean energy attributes would be allocated to the individual states or consumers consistent with their submitted demand bids.

The three-year forward ICCM auction would procure capacity and clean energy requirements sufficient to meet all system and local reliability needs and serve all demand for clean energy attributes at the lowest combined cost. The resulting market prices would incentivize private investors to identify low-cost solutions to meet reliability and decarbonization needs, drawing on the broad regional marketplace to drive efficiencies and competitive prices.

FIGURE 12: THREE-YEAR FORWARD ICCM AUCTION FOR CAPACITY AND CLEAN ENERGY NEEDS



Regional Scope, Governance, and Implementation: A PJM-wide ICCM could be pursued as a regional solution to MOPR-related conflicts that could ultimately be implemented by PJM and replace the current RPM structure. Downside risks are minimized under this implementation paradigm, due to strong regional existing mitigation structures as well as relying on PJM's existing infrastructure and capabilities to implement the ICCM design. This preferred implementation structure would offer the greatest economic and environmental benefits with the lowest downside risk to New Jersey.

Potential Sub-Regional Scope, Governance, and Implementation: Alternatively, a New Jersey-alone or multi-state ICCM could be implemented under the current PJM Tariff rules for an FRR. As with other FRR structures, this would necessitate establishing an independent auction administrator and FRR entities to engage in settlements with PJM. States' joint effort to develop and implement the Regional Greenhouse Gas Initiative (RGGI) is a potentially helpful example of how a collective of like-minded states could create an entity that would be empowered run an environmentally-focused market driven by participating members' requirements. The New Jersey-alone approach to ICCM would offer the state the greatest control over the design and implementation schedule.

State Participation as Clean Energy Buyers: A central tenet of the ICCM is that states would set their own policy goals. Each state would determine whether to adopt clean energy mandates, the scale of these mandates, which resources are eligible, applicable budget caps, and whether to procure clean energy via the ICCM or via other mechanisms. The ICCM would be tailored to each state's unique policies, while enabling participating states to tap into the competitive benefits of a broad regional marketplace for clean energy.

Voluntary Buyers of Clean Energy: In addition to state demand for clean energy, there are many other entities that may wish to participate within the ICCM as voluntary buyers of clean energy. Such entities could include cities, competitive retailers, corporate sustainability buyers, public power entities, or integrated utilities. Such voluntary buyers may operate within states with no clean energy mandates, or may wish to exceed any applicable state mandates. Through the ICCM, these buyers would be able to submit voluntary demand bids for clean energy attributes (and specify a maximum price they are willing to pay).

Role of the RTO: As the RTO, PJM would continue to establish the quantity of capacity needed regionally and by location to maintain system reliability consistent with the 1-event-in-10-years ("1-in-10") reliability standard.

Seller Participation: Qualified resources, both clean and emitting, identify a total annual payment that they would require to provide capacity and/or clean energy in the relevant delivery year.

- *Clean resources* would be eligible to sell both capacity and clean energy.[64] These resources would offer their resources' capability into the auction at one price and two quantities (*i.e.*, they will specify one total payment needed in order to deliver their total qualified volumes of each capacity and clean energy). Clean resources would also be eligible to lock in their clean energy payment prices for up to seven years, as a means to provide investment certainty.
- *Emitting resources* would only be eligible to sell capacity.

Role of the Auction Administrator: The auction administrator would conduct a three-year forward auction to determine the lowest-cost mix of clean and emitting resources necessary to meet: (i) the clean energy requirements expressed by each state and customer; and (ii) the capacity needed to meet regional and locational reliability needs.

- The auction administrator would utilize a co-optimized single auction to meet all capacity and clean energy needs at the lowest combined procurement cost. The auction would continuously adjust the selection of cleared resources until the most advantageous portfolio of resources in the system is identified (see Appendix B for more detail). The auction would produce two simultaneous "clearing

[64] Rules governing emitting resources using carbon capture and sequestration will have to be developed if the technology becomes commercially available in the PJM regions. Further discussion would be required to establish eligibility rules that might award clean energy credits in proportion to the emissions sequestered.

prices," one for clean energy (priced in \$/CEAC, \$/REC, or \$/ZEC as applicable for a given state) and one for traditional capacity service (priced in \$/MW-day as applicable for each location).

- By co-optimizing the two products within a single auction, consumers would benefit from identifying the lowest-cost, fully reliable system that meets the share of clean energy required by state policies while having the necessary resources to contribute to capacity needs.
- Because sellers identify the amount of capacity and clean energy they have to sell separately, clean resources benefit from having two sources of revenue that adjust to the efficient level as part of the simultaneous clearing process.
- The price signals that result from the single auction would demonstrate the need for reliable, clean energy, by location, depending on the appetite of a state or buyer for clean energy.

B. State Participation within the ICCM

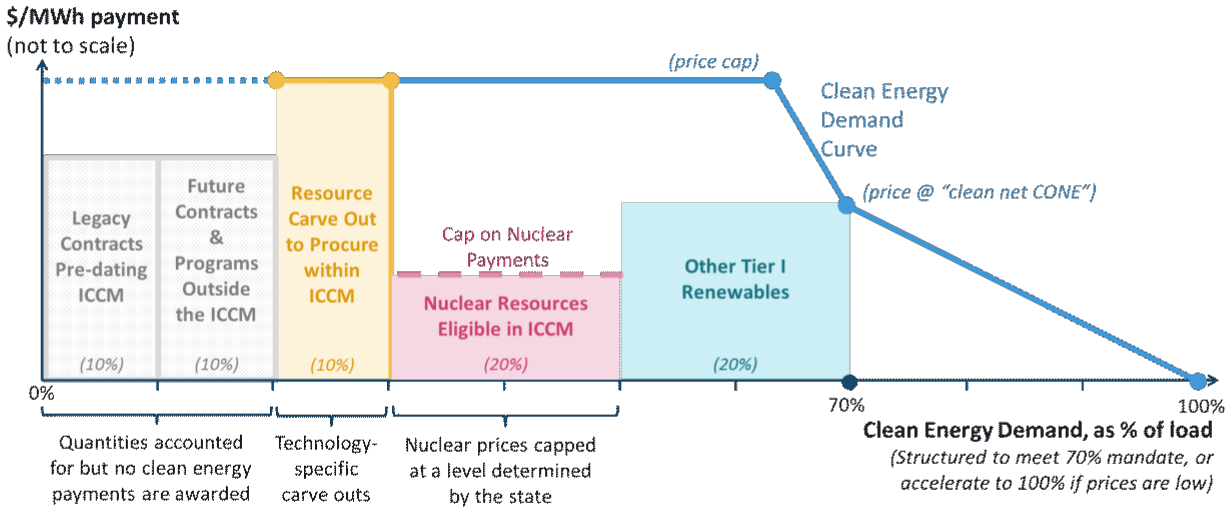
State participation as clean energy attribute buyers in the ICCM would be voluntary.[65] Meeting capacity requirements would continue to be mandatory for all customers, but could be met bilaterally or via the ICCM. States wishing to procure clean energy through the ICCM could determine the volume of clean energy they wish to procure and the prices they are willing to pay. In the alternative, a state may direct the auction administrator to translate existing state policy goals that the state wishes to procure competitively through the ICCM, into these price and quantity values consistent with state law, for review and approval by the state. Each state would retain the flexibility to tailor the structure of their demand bids consistent with state policy objectives.

States would have the option to use a downward-sloping demand curve to express their willingness to pay for clean energy. There are a number of benefits to using a sloped demand curve. A sloping curve mitigates year-to-year price volatility as market conditions fluctuate and mitigates potential exercise of market power. These beneficial price formation properties can stabilize pricing in a way that helps to support the financing of new resources when needed. A sloping curve can also help balance program costs against the pace of decarbonization to achieve faster carbon abatement if this can be done at reasonable costs to the consumer.

Within the total clean energy procurement target, many states will also have a variety of state programs or procurements that need to be accommodated. Some of these state programs would be reflected as a part of a state's total demand for clean energy within ICCM, while others would be procured outside the ICCM. As an example, Figure 13 illustrates the demand of a "typical" state with multiple policies including ZEC payments for existing nuclear resources and a renewable portfolio standard with technology-specific carve outs. The ICCM can be used to meet the overall state policy goals while accounting for existing contracts and future clean energy procurements that may occur outside the ICCM.

[65] Corporate buyers seeking to acquire clean energy could also develop a demand curve to express their increased willingness to pay for clean energy, including selecting new resources or purchasing only from their preferred state-specified REC products. Other ways of enabling and supporting private demand for clean energy would be evaluated on an ongoing basis.

FIGURE 13: CLEAN ENERGY DEMAND IN ICCM FOR A STATE WITH MULTIPLE CLEAN ENERGY POLICIES



To meet these particular goals, the state demand could be reflected within the ICCM as:

- **Overall Clean Energy Demand Curve** (blue line): The state would translate (or ask the ICCM auction administrator to translate) its total appetite for clean energy into a state-specific demand curve. In this example, the total state demand for clean energy is 50% renewables, plus 20% under the ZEC program (70% total clean energy mandate). This total demand for clean energy is expressed by the total state demand curve (blue line). The specific price and quantity parameters of the curve would be developed or approved by each state's policymakers consistent with state policy and adjusted over time. Resources cleared within the blue area would receive prices set by the intersection of supply with the blue demand curve, and would be obligated to produce and deliver Tier 1 RECs as defined by that particular state. Additional discussion of how states might wish to implement their demand curve is included in Appendix B.
- **Legacy Contracts and Procurements Outside of ICCM** (gray boxes): States would maintain total flexibility to continue using existing or future programs other than the ICCM at their own discretion. In this example, the state anticipates meeting 10% of its clean energy mandate through legacy contracts. It further anticipates meeting an additional 10% of its clean energy needs through future programs or procurements outside the ICCM construct (for example, through a specific state-sponsored resource investment). The volumes of clean energy from any contracts signed outside of ICCM would be accounted for in auction clearing (but the resources would not earn any attribute payments). These clean energy resources would be fully enabled to sell capacity into the ICCM capacity product with no MOPR. After legacy contract expiration, these resources would become eligible to participate in ICCM as existing resources eligible to earn both capacity and clean energy attribute payments.
- **Technology-Specific Carve Outs within ICCM** (yellow box): Some states may have technology-specific mandates such as for in-state solar or offshore wind within their clean energy standards. The states may elect to achieve these minimum procurements within the ICCM by specifying a minimum share of the total demand that must be met by resources qualified under the particular technology type to produce the relevant class of attributes such as solar RECs (Solar Renewable Energy Certificate or SRECs) or offshore wind RECs (ORECs). States could choose to apply a different price cap and different new resource lock-in period for these carve-out resources than the generalized clean energy demand curve. The carve outs might produce higher (but not lower)

clearing prices for the SREC, OREC, or other attributes created by these preferred technology types.[66]

- **Nuclear Resources** (pink box): Each state would determine the extent to which nuclear resources would be eligible to contribute to their clean energy goals, including whether only in-state nuclear resources could qualify or whether out-of-state nuclear resources could also qualify. States can impose a $/ZEC cap on payments awarded to nuclear supply and/or on volumes of nuclear supply eligible to serve their total clean energy demand. This structure introduces downside price competition for nuclear resources from other sources of clean energy supply, but can prevent payments in excess of nuclear program budgets.
- **Other Tier 1 Renewables** (blue box): All other qualified resources could compete to serve the state's demand for clean energy, up to the maximum price and quantity defined in the total state demand curve for clean energy.

Together, these structures offer each participating state total flexibility to meet none, some, or all of their clean energy needs within the ICCM.[67] While procuring all of the state's clean energy objectives through the ICCM would result in the lowest-cost path to decarbonization, each state still maintains the ability to procure clean capacity outside the market or voluntarily pay a premium for resources that they see as necessary to achieve their public policy goals. To maximize the competitive benefits of the ICCM over time, participating states can collaborate on opportunities to increase the quantities procured, reduce the volume of resource carve outs, increase alignment of resource qualification across states, and shift their demand toward procuring greater volumes from the PJM regionally-defined CEAC product that would qualify all clean resources across the PJM footprint.

C. ICCM Implementation Choices

Staff have developed the ICCM design concept as one viable and fully-specified approach to address the broad problems identified within the current RPM market structure. (This is unlike the FRR alternative variations considered above that were primarily tailored to address only one problem: the application of MOPR to policy resources.) An ICCM structure would offer the flexibility to implement a number of additional design elements within the same basic ICCM framework, and also offers a number of beneficial features that should be considered to enhance the performance of the RPM even if the ICCM were never implemented. Some of these design elements and implementation choices include:

- **Features to Be Considered within the PJM Capacity Market (with or without ICCM):** Several aspects of the current RPM design could be enhanced to better align with state and consumer decarbonization goals. Amongst the design options that should be considered regardless of the ICCM implementation include:
  - More accurate ELCC-based capacity accounting for all resources, including thermal power plants;

66 *See* Appendix H.3 here for additional discussion of auction clearing with technology-specific carve outs.

67 As an additional element of flexibility to states concerned about the deliverability of clean energy within their subregion of the grid, the ICCM could be utilized to impose a maximum constraint on the quantity of capacity that could be procured from fossil resources. This constraint would ensure that the remainder of state system and local capacity needs will be supplied by clean energy resources, including non-CEAC-eligible resources such as demand response and storage.

  - Enhanced seasonal resource adequacy accounting and price formation that better reflects resources' capability, summer and winter reliability needs, and the differentiated value of capacity delivered across summer and winter seasons;[68] and
  - Evaluation and consideration of whether flexible capacity requirements are needed and should be reflected within the capacity market construct.
- **Geographic Scope and Governance Structure of the ICCM:** The ICCM could be implemented regionally across PJM, sub-regionally for a group of states, or specifically for New Jersey. Even if the ICCM design remains identical, the governance, implementation, and impacts could differ substantially across these pathways:
  - *PJM-wide implementation* of ICCM would replace the current RPM with a new structure that provides states and consumers greater opportunities to express their resource requirements in the wholesale marketplace. PJM as an organization would be well-positioned to implement and operate this market drawing on its staff expertise and operational capabilities. Existing mitigation capabilities mitigate the exposure to the exercise of market power. This implementation pathway would offer the greatest economic and environmental benefits and place the lowest implementation burden on New Jersey or other participating states; however it may face barriers to implementation absent strong leadership from PJM, FERC, or both.
  - *Multi-state implementation* of an Forward Clean Energy Market, which is a simplified version of ICCM involving the forward procurement of clean energy without a capacity component, might take on a governance format and implementation pathway modeled on the RGGI. Under this implementation approach, two or more states would work together to refine the parameters of the FCEM to tailor it to their policy requirements. An auction administrator would be selected to implement the auction, which could be PJM, another third-party entity, or a newly created organization similar to RGGI. The auction administrator would procure clean energy to meet policy requirements on behalf of each participating state. Also similar to RGGI, the framework would be set up to invite and enable additional states and customers to participate over time and further the underlying aim of delivering a reliable and decarbonized resource mix.
  - *New Jersey or regional implementation* of an ICCM could also be pursued under an FRR plan by a selected auction administrator. Whether developed by New Jersey or a group of clean energy states, the ICCM would be designed to invite additional states to participate in the market over time. This approach would offer New Jersey the greatest opportunity to implement its chosen ICCM design. Further, many of the implementation, liquidity and market power challenges become less significant as the market expands. However, the complexity associated with an FRR option would still apply.
- **State-Defined ICCM Participation Choices:** Each state participating within the ICCM would have the ability to determine the parameters of its participation including: (a) selecting the products it wishes to buy such as state-defined RECs, SRECs, ORECs, or ZECs or PJM-defined CEACs; (b) determining the volume to be procured; (c) selecting the parameters of the state demand curve for attributes (or approving a formula by which the auction administrator would calculate these demand curves).
- **ICCM Design Enhancements that Could Be Implemented at Later Dates**: Some design elements within the ICCM may be desirable but take more time to implement. The evolution of the ICCM

[68] *See* additional discussion of such a two-season capacity market for the PJM region that could achieve approximately $100-$600 million per year in societal costs as compared to the current seasonal resource matching approach. Samuel Newell *et al.*, "Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM," April 12, 2018, pp. 13-16.

design could envision staged implementation that incorporates some design elements over time, such as:

- The development of enhanced PJM-defined CEAC products, such as an attribute credit that is tied to the marginal carbon abatement value of resources (and thus provides greater incentives for resources that displace more carbon, and that provides a basis for valuing storage resources that are operated to charge on clean energy and discharge to displace fossil plant production);[69]
- The adoption of a minimum clean capacity requirement that would allow states to stipulate not only the share of clean energy attributes they demand but also the share of their capacity needs that must be met by clean capacity resources that must be deliverable to serve reliability needs. This approach offers an opportunity to attract and retain clean resources such as nuclear, existing hydro, storage, and demand response that are needed for reliability in a clean energy future and that are not always eligible for state policy support.

These and other features of the ICCM are discussed in more detail in Appendices B-C. Many of these design features could be considered as part of a different long-term sustainable market design for meeting reliability and decarbonization requirements, even if the ICCM itself is not ultimately adopted.

D. Advantages and Disadvantages

This investigation specifically designed ICCM in response to the Board's charge to recommend alternative resource adequacy structures targeted towards efficiently achieving New Jersey's environmental and clean-energy policy goals. Compared to the other resource adequacy alternatives investigated, the ICCM is best aligned to sustainably achieve these policy objectives using market-based approaches to maintain reliability and drive clean energy achievement along the least cost pathway. The ICCM would maintain and expand reliance on competitive approaches, reduce the costs of achieving New Jersey's clean energy goals, and offer the opportunity to accelerate clean energy achievement through a downward-sloping demand curve.

If the MOPR is maintained in its current form, New Jersey would have the unilateral authority to implement a single-state ICCM to achieve these benefits while avoiding the application of the expanded MOPR to its policy resources, though such an approach introduces additional risks. Even if MOPR is eliminated, the single-state ICCM could offer New Jersey the benefits of a competitive mechanism for meeting its various clean energy objectives in alignment with reliability needs. A single state ICCM would come at the cost of exiting the regional capacity market, losing the associated efficiency benefits, introducing implementation risks associated with the FRR, and risks of exercise of market power. A multi-state FRR approach would expand the environmental and economic benefits of the ICCM across a broader regional footprint, but would face some of the same implementation challenges of an FRR, introduce a larger coordination challenge, and reduce the ability for New Jersey to implement its chosen design. The greatest economic and environmental benefits would be achieved under a PJM-wide ICCM, though at that scale New Jersey has the least ability to select its preferred design.

The primary disadvantages of an ICCM are the complexity and barriers to implementation, both of which are amplified if a regional solution is to be pursued. The relative advantages of different ICCM approaches are summarized in Table 3.

[69] For additional discussion of a marginal carbon abatement REC, see Spees, Oates "Locational Carbon Emissions", May 2021; and Appendix H.1, of Spees, *et al.* paper on a forward market for clean energy attributes.

TABLE 3: RELATIVE ADVANTAGES OF ICCM IMPLEMENTATION ALTERNATIVES

DESIGN	ADVANTAGES	DISADVANTAGES
New Jersey ICCM Implemented under FRR	• Eliminate MOPR on policy resources & mitigate/eliminate MOPR costs • Enhance competition among clean energy resources and reduce costs of achieving policy goals • Efficiency benefits of co-optimizing capacity and clean energy procurements • Option to accelerate clean energy achievement if prices are low • New Jersey has unilateral authority to implement its chosen design	• Lose competitive benefits of participation in PJM's broad regional capacity market • Market monitoring and implementation risks of a state-wide FRR, particularly in small capacity areas • Further evaluation required to determine statutory and regulatory authority • High implementation complexity
Multi-State ICCM Implemented under FRR	• Eliminate MOPR on policy resources & mitigate/eliminate MOPR costs • Maintain a share of the benefits from participation in broad regional capacity market, scaled to the size of multi-state region • Enhance competition among clean energy resources and reduce costs of achieving policy goals, scaled to the size of the multi-state region • Efficiency benefits of co-optimizing capacity and clean energy procurements • Option to accelerate clean energy achievement if prices are low • Multi-state approach can reduce costs of transition to clean electricity grid	• Greater coordination challenges to achieve multi-state coalition and alignment for implementation • Further evaluation required to determine statutory and regulatory authority • High implementation complexity
Regional ICCM Implemented by PJM	• Eliminate MOPR on policy resources & eliminate MOPR costs • Maintain full benefits of participation in broad regional capacity market • Maximum competition among clean energy resources and reduced costs of achieving policy goals • Efficiency benefits of regionally co-optimizing capacity and clean energy procurements • Option to accelerate clean energy achievement if prices are low • Broad regional approach can achieve least-cost efficient transition to clean electricity grid • Leverage PJM existing expertise and capability to design and operate the ICCM	• New Jersey's authority to implement its chosen design is reduced under a broader regional approach • Medium implementation complexity, aided by PJM and Stakeholder expertise
Regional Forward Clean Energy Market	• Creates an effective market for financing low cost clean energy resources • Maximize competition among clean energy resources • Ability to be implemented without involvement from federal or regional regulators and may involve fewer jurisdictional issues • (Slightly) less technical complexity than a full ICCM	• Less overall savings compared to a full ICCM implementation • Longer timeframe to stand up a new market structure outside the existing PJM structure • Medium complexity (if implemented by PJM)

V. Economic Assessment of Resource Adequacy Alternatives

To assess the economic implications of alternative resource adequacy structures for New Jersey, Staff engaged with consultants at The Brattle Group. This assessment utilized a model that replicates the outcomes of the PJM capacity auction under the status quo design and after any assumed design changes. Brattle estimated the potential impacts of the various design scenarios on capacity costs, payments for clean energy, patterns of retirement and new entry, and resource supply mix in the years 2025 and 2030. Brattle evaluated the following alternative resource adequacy scenarios:

- **Status Quo:** New Jersey stays in PJM capacity market and pays the cost of the 2019 MOPR.
- **No-MOPR RPM:** New Jersey stays in PJM capacity market, but the 2019 MOPR is repealed.
- **Best-Case Auction-Based FRR (State-Wide or Partial State JCPL-Only):** New Jersey leaves the PJM capacity market and conducts its own FRR capacity auction for one-year capacity commitments with optimistic, near-best-case competitive pricing outcomes achieved in each respective capacity zone. This scenario assumes suppliers of capacity not subject to MOPR are willing to sell capacity in the New Jersey FRR auction at prices only five percent higher than what they would expect to receive in the PJM market, *and* that they are perfectly able to predict their opportunity costs of not participating in the PJM market with no uncertainty, *and* that there would be no excess market power in the FRR auction relative to RPM.[70]
- **IMM-Assumed Pricing for FRR:** New Jersey leaves the PJM capacity market, but implements the FRR under an FRR design that results in higher pricing outcomes in line with the assumptions developed by the Independent Market Monitor (IMM) in a prior analysis of a New Jersey FRR.[71] These realized higher FRR prices could be driven by some combination of sequential-auction pricing uncertainty, lack of supply participation, exercise of market power, and/or implementation flaws. Following the IMM, this scenario assumes prices reach the level of Net CONE times the balancing ratio (equal to 78% based on the PJM 2022/23 parameters).
- **New Jersey-Only ICCM:** New Jersey elects the FRR option and conducts its own ICCM to procure both capacity and clean energy attributes on behalf of customers under a competitive procurement approach, under the same assumptions utilized under the near-best-case auction-based FRR including capacity prices at 5% above subsequent BRA prices. Other states remain in the PJM capacity market and face the costs of the 2019 MOPR; MOPR-influenced pricing also affects capacity prices available to New Jersey under the ICCM.
- **PJM-Wide ICCM:** The entire PJM region adopts an ICCM as an evolution of the current capacity market, achieving the competitive benefits of a no-MOPR full RPM plus a regional clean energy marketplace. Appendix C describes a variation of the PJM-wide ICCM that also imposes clean capacity requirements within the ICCM (that would require the capacity requirement to be served by clean resources).

As inputs to its model, Brattle utilized offer data from the PJM 2021/22 BRA, as updated to reflect future conditions anticipated by 2025 and 2030. Additional modeling detail is included in Appendix A.

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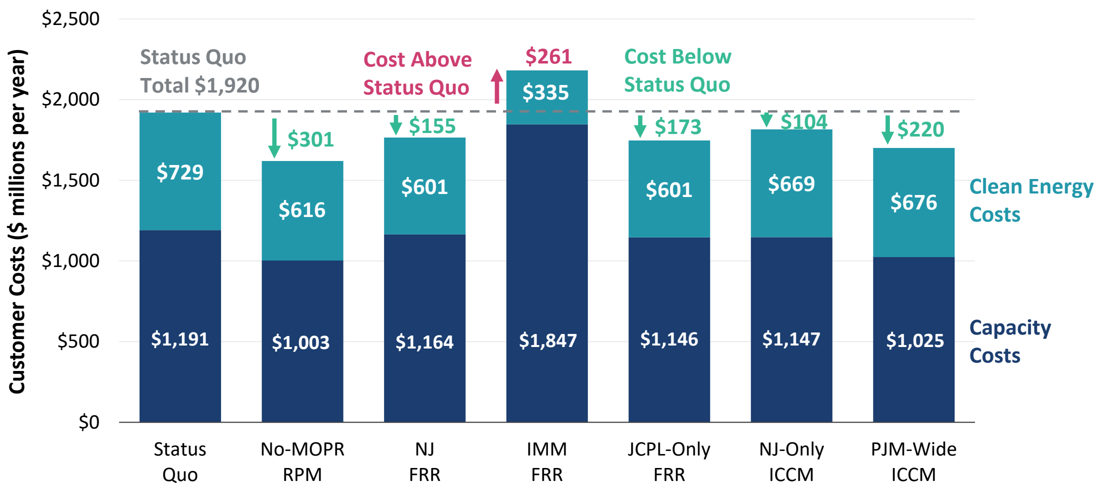
70 Note that certain FRR auction structures could make it more likely to achieve this outcome, such as the RPM-derivative pricing options in which resources were able to express their offer prices as a percentage of subsequent RPM clearing prices.

71 Monitoring Analytics, "Potential Impacts of the Creation of New Jersey FRRs," May 13, 2020.

A. New Jersey Customer Costs

Figure 14 compares the results of the New Jersey customer cost analysis across the seven scenarios examined in 2030 (2025 results can be found in Appendix A). The near-best-case outcome under a competitive FRR leads New Jersey customers to save approximately half of the cost of the current MOPR, regardless of whether the FRR is implemented state wide or for one utility zone. There are two primary drivers of these savings: (1) electing FRR allows thousands of MW of resources that cannot clear due to the expanded 2019 MOPR to provide capacity to New Jersey, thus eliminating the capacity double-payment effect for policy resources; and (2) applying policy resources to serve New Jersey capacity needs increases the supply of capacity in aggregate to the PJM footprint, thus lowering capacity prices for New Jersey customers and other PJM customers alike. These estimates also account for a smaller cost savings from the 3% reduction in procured quantities under an FRR due to the elimination of the sloping capacity market demand curve. The costs of the expanded MOPR are not eliminated by selecting an FRR however, because the broader PJM market prices would still be inflated by MOPR application to resources in other states. A New Jersey FRR auction would need to produce prices at least as high as the prevailing capacity market price in the relevant capacity LDAs order to attract sufficient supply offers.

FIGURE 14: NEW JERSEY CUSTOMER COSTS BY RESOURCE ADEQUACY DESIGN (2030)



Notes: Clean energy resource costs include payments to new onshore wind, offshore wind, and utility-scale solar resources in excess of their energy and capacity revenues. Capacity costs include New Jersey's share of PJM capacity costs (when participating in the PJM auction) or the New Jersey FRR cost (when not).

The substantial cost savings under a "Best Case FRR" depends on the willingness of non-MOPR capacity suppliers to sell into the New Jersey FRR auction at competitive prices. Competitive non-MOPR capacity sellers should rationally offer at the anticipated price in the upcoming BRA (as they would not be willing to accept a lower price to serve New Jersey than to sell into the full PJM market); they would only offer higher if their true underlying net going forward costs of providing capacity were higher. In a competitive market with appropriate measures to prevent the exercise of market power, if sellers could predict RPM prices perfectly or the auction could be constructed to exactly reflect sellers' true opportunity costs, then prices would converge between the FRR auction and subsequent BRA; this scenario assumes FRR prices will have a 5% premium over RPM outcomes.

There are also a number of plausible scenarios under which higher prices than the idealized Best Case FRR could materialize under a New Jersey FRR. Higher prices could arise from suppliers offering at prices above later-realized RPM prices due to uncertainties, lack of supply participation, localized market power, or FRR implementation flaws. If these outcomes were to produce higher prices near the levels previously assumed by the IMM, customer costs could increase (rather than decrease) under an FRR. Under this scenario, the cost savings achieved by avoiding the expanded MOPR on policy resources are more than offset by the higher capacity payments that exceed the pricing that would be available in the broader PJM market. If left unaddressed or locked in under long-term contracts, then a poorly-design or poorly-implemented FRR could cost the same or significantly more than staying within the RPM and accepting the costs of the expanded MOPR. These pricing risks highlight the importance of thoughtful design of an auction-based FRR and avoiding any lock-in of potentially unfavorable prices. The partial-state FRR would substantially limit the exposure to these potentially uneconomic outcomes.

If New Jersey elected the FRR and designed a single-state ICCM to procure both capacity and RECs, New Jersey consumers could save approximately one-third of the costs of expanded MOPR (even if MOPR would remain in place across the broader PJM footprint). The customers savings from the New Jersey ICCM are not as great as under New Jersey FRR, because the state procures additional clean energy through the ICCM (as discussed further below). This design is subject to some of the same challenges of other New Jersey-alone FRR cases as relates to pricing of the capacity product, such as the need to address the potential for exercise of market power. Careful implementation of the New Jersey-only ICCM would be necessary to mitigate such potential outcomes.

A PJM-wide ICCM would save approximately two-thirds of the cost of the expanded MOPR. These costs savings from ICCM would be realized even though New Jersey would substantially increase its clean energy achievement as discussed in the following section, accelerating renewable deployment 50% to 58% by 2030 (from 84% to 92% total clean energy including nuclear).

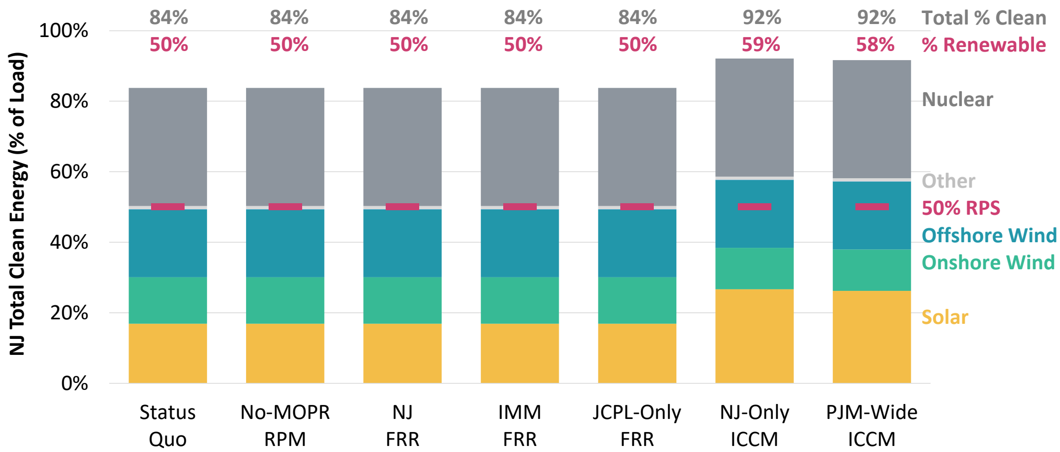
B. Implications for New Jersey Clean Energy Goals

New Jersey's clean energy mix also changes across a subset of the alternative resource adequacy structures. The volume of clean energy resources procured toward New Jersey's clean energy goals does not vary across the Status Quo, No-MOPR RPM, Best Case FRR, or IMM FRR as summarized in Figure 15 for the year 2030. In these scenarios, clean energy additions are chosen to exactly meet the total RPS target and offshore wind procurements levels; total (Class I) renewable supply is equal to 50% of New Jersey load (84% if including nuclear generation).

Both the New Jersey-Only ICCM and PJM-Wide ICCM design scenarios procure substantially more clean energy due to the introduction of a downward-sloping demand curve that can accelerate clean energy procurement.[72] By 2030 a New Jersey-alone ICCM could attract sufficient incremental new clean resources to increase New Jersey's share of load served by renewables from 50% to 59% by 2030 (or from 84% to 92% including both renewables and nuclear supply).

72 The demand curve utilized for New Jersey and all other states within the ICCM construct is described more fully in Appendix B, however the specifics of how New Jersey would choose to implement its demand curve would need to be further developed as consistent with State law.

FIGURE 15: NEW JERSEY ENERGY AND CAPACITY MIX BY RESOURCE ADEQUACY DESIGN (2030)
NEW AND EXISTING CLEAN ENERGY RESOURCES SERVING NEW JERSEY



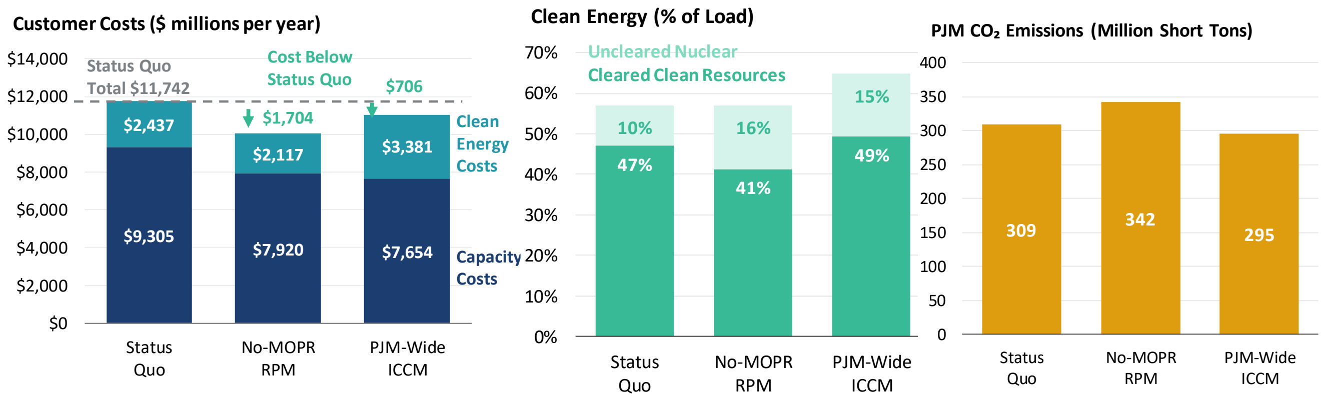
Notes: "Other" clean energy includes landfill gas, other biomass gas, municipal solid waste, geothermal, and in-state hydroelectric facilities less than 3 MW in service after July 23, 2012 currently providing RECs to meet New Jersey's RPS targets.

C. PJM-Wide Impacts on Cost and Resource Mix

A PJM-wide resolution to the expanded MOPR conflicts and better alignment with state policies could offer benefits not only to New Jersey but customers across the entire PJM region. Figure 16 illustrates the differences in customer costs, clean energy penetration, and regional carbon emissions across the cases relevant for regional solution including the status quo, no-MOPR, and regional ICCM design alternatives considered. The simplest option to eliminate MOPR applicability to policy resources would lower PJM-wide customer costs by $1,700 million per year by 2030. However, the share of nuclear resources that may fail to clear the capacity market under a no-MOPR RPM would increase (from roughly 10% to 16% of PJM customer demand) due to lower capacity market prices. This outcome illustrates why the RPM structure, even after the elimination of MOPR, is insufficient to support the most cost effective clean energy transition. Without a means to express their preference to rely on clean energy and clean capacity resources through the market, the RPM may continue to clear fossil resources rather than retaining nuclear (even if states and customers would prefer to pay the incremental cost required to rely on a cleaner supply mix).

Introducing a regional, PJM-wide ICCM would reduce costs by $700 million per year compared to the status quo, while at the same time increasing the share of PJM customer demand served by clean energy from 41% to 49%; cutting regional carbon emissions by 14% across the entire PJM footprint. This outcome is achieved by eliminating the costs of MOPR and redirecting incentives away from fossil resources, benefitting all customers including those with no clean energy policies and those with substantial clean energy goals. At the same time, New Jersey and other clean energy states are assumed to adopt downward-sloping demand curves for clean energy attributes that accelerate renewable development, the associated costs borne by the consumers within that state. Overall, the effect of the ICCM is to shift resource incentives away from the development and retention of fossil plants and toward the development of incremental renewable energy.

FIGURE 16: PJM-WIDE CUSTOMER COSTS, CLEAN ENERGY AND CARBON EMISSIONS



VI. List of Acronyms

AECO	Atlantic City Electric Company
AEP	American Electric Power Company
APS	Allegheny Power Systems
ATSI	American Transmission Systems, Inc.
ATSI-C	American Transmission Systems, Inc. – Cleveland
BGE	Baltimore Gas and Electric Company
BRA	Base Residual Auction
CETL	Capacity Emergency Transfer Limits
CEAC	Clean Energy Attribute Credit
ComEd	Commonwealth Edison
Dayton	Dayton Power and Light Company
DEOK	Duke Energy Ohio and Kentucky
DLCo	Duquesne Lighting Company
DPL	Delmarva Power and Light Company
EKPC	East Kentucky Power Cooperative
ELCC	Effective Load Carrying Capability
EMAAC	Eastern Mid-Atlantic Area Council
FERC	Federal Energy Regulatory Commission
FRR	Fixed Resource Requirement
FCEM	Forward Clean Energy Market
ICAP	Installed Capacity
ICCM	Integrated Clean Capacity Market
IMM	Independent Market Monitor
IRM	Installed Reserve Margin
JCPL	Jersey Central Power and Light Company
LDA	Locational Deliverability Area
LSE	Load-Serving Entity
MAAC	Mid-Atlantic Area Council
MetEd	Metropolitan Edison Company
MOPR	Minimum Offer Price Rule
MW	Megawatt
Net CONE	Net Cost of New Entry
OPSI	Organization of PJM States, Inc.
PJM	PJM Interconnection
PSEG	Public Service Electric & Gas Company
PS-North	PSEG North
RGGI	Regional Greenhouse Gas Initiative
RTO	Regional Transmission Organization
RPM	Reliability Pricing Model
REC	Renewable Energy Credit

RPS	Renewable Energy Portfolio Standard
SREC	Solar Renewable Energy Certificate
SWMAAC	Southwest Mid-Atlantic Area Council
UCAP	Unforced Capacity
VRR	Variable Resource Requirement
ZEC	Zero-Emissions Certificate

VII. Appendices

A. Modeling Details

This appendix provides additional detail on modeling input assumptions and results as developed by Brattle and summarized in Section V above. Though price and other outcomes are subject to a number of uncertainties, the analysis has applied consistent assumptions across all studied resource adequacy design alternatives.

Supply Offers. The model of the PJM region in 2025 reflects confidential supply offer data from the 2021/22 auction received from PJM, adjusted for announced retirements and new entry. For 2030, this supply curve is updated based on public data and estimate the long-run average avoidable net going forward costs of supplying capacity, which yields a more elastic 2030 supply curve.[73] Consistent with recent market experience, the modeling assumes that new entry of gas combined cycle and renewable resources can be attracted at prices 20% below the administrative estimate of the net cost of new entry (Net CONE), with new resource costs projected to decline consistent with National Renewable Energy Laboratory (NREL) projections.[74] The approach produces outcomes with greater price differences in 2025 than in 2030 caused by the same quantity of supply or demand changes. This accounts for the fact that in the short-term capacity prices can be quite sensitive, with large price changes driven by relatively small changes in supply or demand. However, over the longer term, extreme pricing impacts will tend to be moderated by supply exit (in the case of persistent low prices) and new entry (in the case of persistent high prices).

Demand and Transmission Parameters. This modeling assumes that policy-supported resources must offer at least the default MOPR price when subject to MOPR. The capacity demand curve reflects the 2022/23 PJM RPM demand curve, updated to 2025/26 and 2030/31 conditions to account for changes in peak demand by LDA and anticipated changes in Net CONE. CETL into each LDA are assumed to stay constant throughout the study period.

Auction-Based FRR Options. The various FRR options are modeled as sequential auctions, with PJM resources offering into the FRR auction at their economic costs, including opportunity costs of not clearing the subsequent PJM BRA. The near-best-case FRR and New Jersey ICCM cases assume that suppliers project RPM revenues with near perfect foresight (leading to a 5% price premium in FRR clearing prices relative to the RPM prices in most LDAs). The IMM-Assumed Pricing FRR case assumes that FRR prices are set at the balancing ratio times Net CONE.[75] Capacity demand curves in the FRR are vertical at the New Jersey reliability requirement.[76]

New Jersey ICCM. In the New Jersey ICCM, the present offshore wind carve-outs to the RPS remain in place as today. In addition, a new demand curve for the clean energy attribute is implemented as discussed in Section IV that reflects demand for the incremental (non-carveout) clean energy needed to meet the RPS at a $/MWh reference price given by the expected cost of new clean entry, net of energy

[73] Monitoring Analytics, "CONE and ACR Values – Preliminary," January 28, 2020.

[74] "2020 Annual Technology Baseline," National Renewable Energy Laboratory.

[75] Assumption derived from the IMM study of FRR implementation in New Jersey. Monitoring Analytics, "Potential Impacts of the Creation of New Jersey FRRs," May 13, 2020.

[76] We adjust the reliability requirement for energy efficiency and price-responsive demand in accordance with PJM's accounting for these factors in the determination of RPM demand curves.

and capacity revenues. Solar and onshore wind are assumed to be able to provide clean energy and capacity, though the capacity value of both is assumed to decline as penetration increases. The demand curve slopes down to a point reflecting 100% clean energy at $0/MWh price. As in the simple FRR cases, capacity subject to MOPR in the rest of the PJM footprint can also offer capacity at non-MOPR prices, subject to limits by LDA of the amount of local capacity needed to meet the FRR requirement.

PJM-Wide ICCM. In the PJM-Wide ICCM, the capacity and clean energy attribute markets are co-optimized across the PJM footprint. States' offshore wind carve-outs are maintained, with additional generic clean energy available from either solar or onshore wind, whichever is most economic (considering both their clean energy value and capacity value at the prevailing clean and capacity prices). The PJM-wide demand curve for clean energy is implemented similarly to the one developed for New Jersey and applies only to states that have already adopted renewable portfolio standards.

PJM-Wide ICCM with Clean Capacity Requirements (results in Appendix C). In addition to the assumptions described above in the PJM-Wide ICCM, this scenario enforces a minimum constraint on clean *capacity* that is available and deliverable to consumers in clean energy. Separate clean capacity constraints are imposed system-wide, as well as in MAAC, SWMAAC, and EMAAC capacity areas.

Table 4 provides a summary of prices, costs, and quantities procured across study years and alternative market design scenarios.

TABLE 4: SUMMARY OF ECONOMIC RESULTS BY RESOURCE ADEQUACY DESIGN

PANEL A: 2025

		Status Quo	No-MOPR RPM	NJ FRR	IMM FRR	JCPL-Only FRR
New Jersey Customer Costs						
Capacity						
Cleared UCAP MW	*(UCAP MW)*	20,641	20,772	20,413	20,413	20,582
Uncleared NJ MOPR Resources	*(UCAP MW)*	2,028	1,567	854	854	854
Average NJ Capacity Price	*($/MW-day)*	$197	$171	$194	$222	$190
Capacity Costs	*($ Millions/yr)*	$1,483	$1,297	$1,442	$1,655	$1,426
Contracts and Clean Energy			26			
Renewable Energy Supply	*(% of Load)*	38%	38%	38%	38%	38%
Clean Energy Supply	*(% of Load)*	73%	73%	73%	73%	73%
CEAC Price	*($/MWh)*	n/a	n/a	n/a	n/a	n/a
Contracts and Clean Energy Costs	*($ Millions/yr)*	$453	$381	$374	$301	$373
Total New Jersey Customer Costs	***($ Millions/yr)***	**$1,936**	**$1,678**	**$1,817**	**$1,956**	**$1,799**
Change vs. Status Quo	*($ Millions/yr)*	*n/a*	*($259)*	*($120)*	*$19*	*($137)*

PANEL B: 2030

		Status Quo	No-MOPR RPM	NJ FRR	IMM FRR	JCPL-Only FRR	NJ-Only ICCM	PJM-Wide ICCM	Low Clean Capacity	Mid Clean Capacity	High Clean Capacity
New Jersey Customer Costs											
Capacity											
Cleared UCAP MW	*(UCAP MW)*	21,523	21,626	20,988	20,988	21,366	20,988	21,660	21,761	21,931	22,023
Uncleared NJ MOPR Resources	*(UCAP MW)*	2,427	0	0	0	0	0	0	0	0	0
Average NJ Capacity Price	*($/MW-day)*	$152	$127	$152	$241	$147	$150	$130	$117	$158	$210
Capacity Costs	*($ Millions/yr)*	$1,191	$1,003	$1,164	$1,847	$1,146	$1,147	$1,025	$931	$1,264	$1,687
Contracts and Clean Energy			25								
Renewable Energy Supply	*(% of Load)*	50%	50%	50%	50%	50%	59%	58%	58%	58%	59%
Clean Energy Supply	*(% of Load)*	84%	84%	84%	84%	84%	92%	92%	92%	92%	92%
CEAC Price	*($/MWh)*	n/a	n/a	n/a	n/a	n/a	$17	$18	$18	$18	$17
Contracts and Clean Energy Costs	*($ Millions/yr)*	$729	$616	$601	$335	$601	$669	$676	$671	$650	$640
Total New Jersey Customer Costs	***($ Millions/yr)***	**$1,920**	**$1,620**	**$1,765**	**$2,182**	**$1,747**	**$1,816**	**$1,700**	**$1,602**	**$1,915**	**$2,327**
Change vs. Status Quo	*($ Millions/yr)*	*n/a*	*($301)*	*($155)*	*$261*	*($173)*	*($104)*	*($220)*	*($318)*	*($6)*	*$407*

Note: Monetary values reported in nominal dollars.

B. Design Details of the Integrated Clean Capacity Market

The ICCM is a state or regional market design for attracting and retaining the least-cost set of resources for maintaining grid reliability, achieving state electricity goals, accelerating clean energy adoption, empowering customers, and unlocking innovative new technologies. The ICCM builds on best practice by using a centralized competitive auction to meet capacity and clean energy needs through competitive merchant investments.[77] Supply resources continue to participate in the energy markets and earn energy

[77] Many design details of the resource adequacy market will be derived from the current practice of PJM RPM capacity market; many design details of the clean energy product procurement will be derived from the Forward Clean Energy Market (FCEM) design proposal described in the appendix of: Kathleen Spees, *et al.*, "How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals: Through a Forward Market for Clean Energy Attributes," September 2019.

market revenues as they do today. This ensures that the resource adequacy market achieves a resource mix that is both reliable and consistent with participating states' decarbonization goals and public policies.

The ICCM clearing engine starts with the assumption that the market will procure enough clean energy (denominated as regionally-defined CEACs, state-defined RECs, or state-defined ZECs) to meet each participating state's clean energy requirements. The total clean energy accounted for will include resources selected through the ICCM as well as those procured outside the ICCM and offsetting each state's clean energy requirements.[78] Because the ICCM procures the specified percentage of clean energy in a competitive fashion, there is no longer any need for a MOPR; all clean energy resources are eligible to clear the ICCM auction without mitigation. The ICCM auction clearing engine determines the lowest-cost suite of clean and emitting generation resources to procure the specified volume of clean energy, account for state policy procurements outside of ICCM, *and* commit enough capacity to satisfy all regional and local reliability constraints. The ICCM thus simultaneously procures two distinct products (capacity and clean energy) at the lowest combined cost, while accommodating state policy.

Resources will offer qualified quantities of both capacity MW and clean energy MWhs, up to a maximum determined under eligibility rules. Capacity and clean energy will clear at two different prices (denominated in $/MW-day of unforced capacity (UCAP) for capacity and in $/CEAC, $/REC, or $/ZEC for each MWh of clean energy). Cleared capacity and clean energy products will be committed for delivery in the specified ICCM delivery year, which is three years after the auction is conducted. ***Because the ICCM integrates clean energy and locational capacity requirements into a single auction, it could entirely replace the existing RPM structure, while also advancing decarbonization at a regional scale.***

[78] Resources procured outside of ICCM could include (but is not limited to): resources procured under state solicitations, resources approved under state planning, or resources developed under incentives programs that the state wishes to maintain outside the ICCM construct. States could choose to maintain any and all such existing programs (which would reduce the volumes procured via ICCM), or could utilize the ICCM to meet their entire clean energy demand.

DETAILED DESIGN STRAW PROPOSAL SUMMARY

The ICCM would procure two products: (1) capacity and (2) clean energy. Table 5 provides design details describing how capacity and clean energy needs would be defined and procured.

TABLE 5: ICCM DESIGN PROPOSAL DETAILS FOR CAPACITY AND CLEAN ENERGY NEEDS

	Capacity *Denominated in $/MW-day UCAP*	**Clean Energy** *Denominated in $/ CEAC, $/REC, or $/ZEC*
Who Sets Demand?	• PJM	• State policymakers (who may delegate demand curve development to the auction administrator) • Voluntary buyers (retailers, companies)
Product Definition	• Unforced capacity (UCAP MW) • Keep locational specificity (as today) • Accurate accounting of capacity needs and values of resource types	• Unbundled clean energy attributes • States can buy regionally-defined CEACs, or state-defined REC or ZEC products • <u>*Consider*</u>: CEAC accreditation tied to carbon abatement value
Supply Eligibility	• All clean and fossil resources are eligible • Effective load carrying capability (ELCC) accounting used to develop resource-neutral capacity values (by location, season, and flexibility)	• CEACs: clean energy resources across PJM • RECs: state-defined eligibility, including for technology-specific classes of RECs to fulfill carve-out requirements • ZECs: each state determines whether in-state and out-of-state nuclear qualifies • Each state can specify eligible technologies (but aim to limit cross-state differences to maximize competition)
Quantity to Procure	• Quantity needed to support 1-in-10 reliability standards • Based on advanced reliability modeling that considers resource characteristics and flexibility needs in the clean grid • <u>*Consider*</u>: State option to impose a maximum on the share of capacity procured from fossil plants	• States and customers set demand quantity • Pre-existing contracts are fully accounted for as self-supply • In vertically integrated or other Fixed Resource Requirement states, the resource mix is approved by the state and not subject to ICCM
Willingness to Pay for each Product	• Sloping demand curves for each system-wide and locational capacity requirement • <u>*Consider*</u>: Separate demand curves for summer/winter needs and "flexible" capacity needs	• States submit or approve an auction-administrator-developed sloping demand curves for total clean energy demand, and carve out requirements (if any) • Voluntary buyers can submit price-quantity pairs to exceed state mandates, for regional CEACs or state-defined RECs/ZECs

AUCTION FORMAT, RESOURCE CLEARING, AND PRICE SETTING

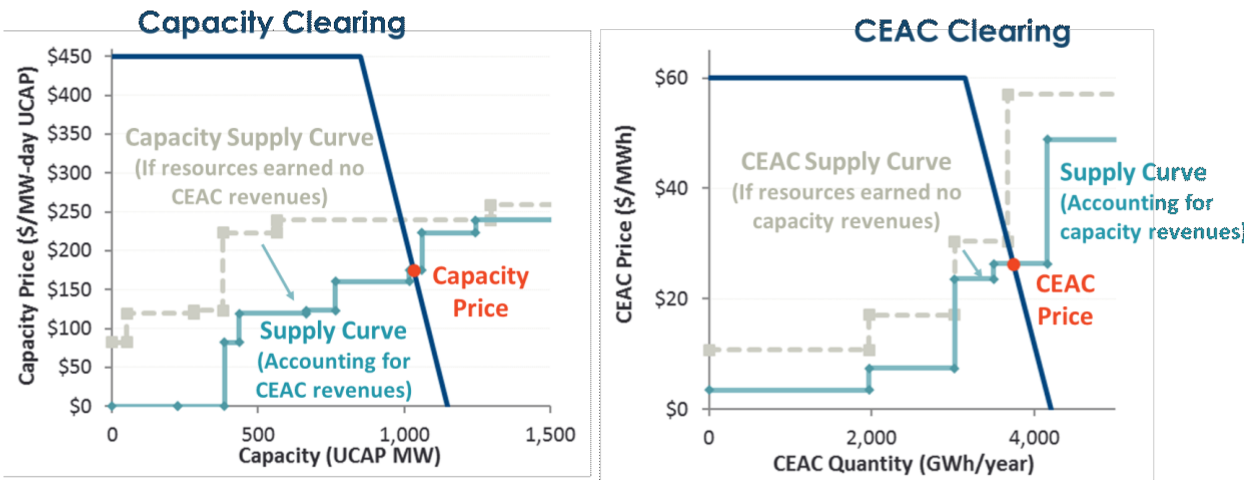
The ICCM auction format and clearing procedures derive from best practices in resource adequacy market design while incorporating certain new design concepts to ensure that clean energy needs are procured alongside capacity. The approach used to procure this least-cost, clean resource mix includes:

- **Three-Year Forward Auction:** The auction administrator would conduct an auction for each year to procure enough capacity and clean energy to meet system needs three years later. For example, the auction conducted in 2025 would procure capacity and clean energy for delivery in 2028.
- **Single-Round, Uniform Price:** The auction format would be a single-round auction that would produce a separate, uniform clearing price for each clean energy and capacity products (*i.e.*, single clearing price for each distinct product).
- **Optimized Clearing:** The auction would clear using a surplus-maximizing optimization formulation. This would maximize the value of cleared capacity and clean energy to states and customers, minus the cost of procured resources. This optimal resource mix is identified by continuously adjusting the set of cleared resources; determining the relevant clearing price for each product as consistent with the total volume cleared on the capacity and clean energy demand curves; assessing which resources would wish to clear (or not to clear) consistent with those prices; and then readjusting the selection of cleared resources. This is comparable to today's capacity market design.
- **Price-Setting Based on Marginal Value:** Prices for each product would be set based on marginal value (*i.e.*, at the intersection of supply and demand). To the extent that locational transmission constraints apply, capacity prices may differ by LDA, just as in today's capacity market. If a state wishes to meet a technology-specific carve out, such as for in-state solar, the ICCM will also support this through a separate class of RECs for the targeted resource type. The auction will include a constraint requiring the minimum share of RECs be procured from resources eligible to meet the technology-specific carve out. Any such state carve-out REC product may clear at higher prices than the more broadly-defined CEAC product. If states impose a separate (smaller) cap on ZEC volumes or program costs, this could produce a lower clearing price for ZECs delivered to their state.

Viewed from the customer's perspective, this auction format seeks to identify the lowest-cost portfolio of resources to meet capacity and clean energy needs by continuously adjusting resource selection until the lowest possible total procurement cost is achieved. Viewed from the seller's perspective, the same auction format seeks to clear any resource that can earn its total revenue requirement from some combination of clean energy and capacity payments; the auction would exclude any resource that cannot earn sufficient revenue to cover its offer price. Overall, the outcome from the auction maximizes social value by identifying the least-cost solution for customers and ensuring that sellers' private incentives align with auction outcomes (*i.e.*, profitable projects clear while unprofitable projects do not).

Figure 17 illustrates auction clearing and price setting in a simplified example. The curves illustrate the capacity demand curve developed by the auction administrator (on the left) and the clean energy demand curve developed by each state or voluntary commercial buyer, as described further below (on the right). Sellers offer their resources at the minimum payments they would accept to take on the obligation to sell both capacity and clean energy attributes. The gray dashed supply curves are drawn as if the seller would need to earn its entire offer price from just one product. The lower aqua supply curves account for clean energy revenues driving a lower capacity supply curve (and vice versa, with capacity revenues driving a lower clean energy supply curve).

FIGURE 17: CO-OPTIMIZED PRICE FORMATION REFLECTING THE MARGINAL COST OF EACH PRODUCT



Notes: Simplified simulation illustrating ICCM procurement outcomes in a simplified example, contact authors for the underlying model used to create this numerical example.

This simplified example illustrates that by optimizing the procurement across both products, prices and customer costs can be reduced. If the auction were designed to narrowly focus on capacity procurement (as the RPM market does today), it would likely procure capacity primarily from fossil plants and attract investments in new gas combined-cycle resources. This outcome runs counter to policy goals in many states by expanding the reliance on fossil resources even for states that wish to decarbonize. States would then need to conduct separate solicitations for clean energy resources, inducing an excess of total capacity in the market and leaving customers to pay for duplicate resources. This double-payment problem is amplified by the expanded MOPR construct that will increasingly exclude clean energy resources from the capacity market, however some of the inefficiencies and customer costs associated with a sub-optimal resource mix would persist in the RPM even without MOPR.

A joint auction resolves these inconsistencies in ways that will drive the resource mix toward an efficient balance of firm capacity needed for reliability and bulk clean energy resources needed to decarbonize the grid. As illustrated in Figure 17 above, the price paid for capacity will go down as clean resources earn a portion of their revenue requirements from the CEAC product. CEAC payment prices will also go down as clean resources earn a portion of their revenues from selling capacity. These customer savings do not occur by accident, but rather by utilizing competitive forces to drive the right quantity and the right mix of supply to meet all system needs.

HOW RELIABILITY IS MAINTAINED WITHIN THE ICCM

PJM Interconnection will continue to set reliability standards both system-wide and by LDA. However, the auction administrator (whether PJM or another entity) would take on responsibility for ensuring that sufficient capacity is procured to meet these standards. PJM will have the following responsibilities associated with its mandate of maintaining the 1-in-10 reliability standard:

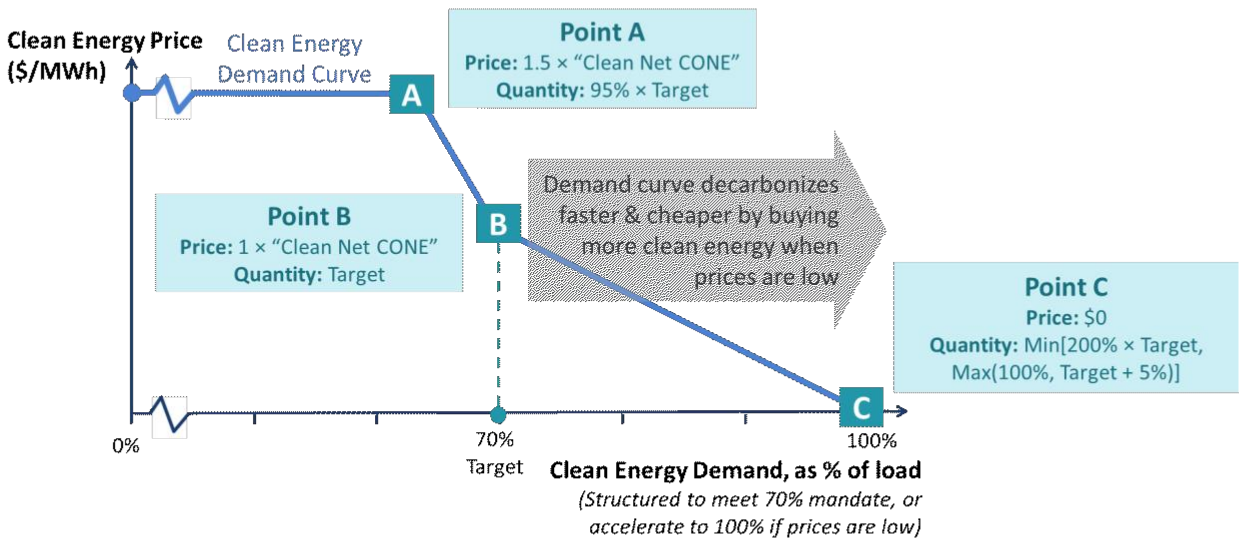
- Determining the Reliability Requirement or UCAP MW quantity of supply needed system-wide and within each LDA in order to maintain reliability;
- Determining the UCAP MW ratings of each eligible supply resource including both fossil and clean energy resources, developed in a technology-neutral fashion such that 1 UCAP MW of capacity has the same reliability value regardless of the underlying technology type;

- Determining which LDAs must be separately considered for reliability purposes and calculating the CETL of supply that could be imported into each LDA; and
- Enhancing current reliability accounting practices to align with the region's clean energy transition, including considering: (a) more accurate accounting of resources' reliability value and ensuring full participation of emerging clean energy technologies; (b) separate summer and winter reliability requirements; and (c) flexible capacity requirements.

The auction administrator will take these reliability parameters as inputs into the ICCM. The auction administrator will translate capacity needs into system-wide and locational demand curves for capacity, and will ensure that CETL and other reliability constraints are appropriately reflected within ICCM auction clearing. Based on this foundation of accurate supply and demand accounting, the ICCM will be able to ensure reliability by procuring sufficient UCAP MW to meet all system and locational reliability needs.

THE SHAPE OF STATE-DEFINED DEMAND CURVES

FIGURE 18: ILLUSTRATIVE DEMAND CURVE FOR A STATE WITH A 70% CLEAN ENERGY TARGET



For the purposes of this proposal, a draft state design curve could be defined by three price and quantity points that would be updated each year using a formula that reflects each state's willingness to pay to achieve carbon abatement, as illustrated in Figure 18:

- **Point B:** The curve is anchored at "Point B," which is the procurement target at a price equal to the Clean Resource Net Cost of New Entry ("Clean Net CONE"), calculated as the estimated CEAC price that would be needed to attract new clean energy resources into the PJM region (*i.e.*, the net of anticipated energy, ancillary service, and capacity payments).[79]
- **Point C:** To the right of the anchor point, the demand curve slopes downward and reaches "Point C" at a price of zero at either (i) double the procurement target if clean energy targets are below 50% of electricity load; (ii) at 100% of forecasted electricity demand if the clean energy target is between 50 and 95%; or (iii) at the target plus 5% for clean energy targets exceeding 95%. This low-priced portion of the demand curve enables the state to pursue an accelerated pace of decarbonization if it is possible to do so at low cost.

[79] This proposal envisions Clean Net CONE being determined through a periodic expert review in accordance with the ICCM governance structure.

- **Point A:** To the left of the anchor point, the curve slopes up to the price cap at "Point A". The price is capped at 1.5 times Clean Net CONE, at a quantity 5% less than the target. States would have the flexibility to adjust the price and quantity at Point A in order to only procure CEACs below a threshold price cap or program budget cap. This higher-priced portion of the demand curve allows the pace of decarbonization to moderate slightly if CEACs are only available at high prices (e.g., in case there is a period with high commodity prices or tight financial market conditions). During such a time, a state may wish to take a somewhat moderated pace as a cost mitigation decision.

These price and quantity points are a reasonable starting point for states that wish to use a demand curve approach, though the specific formula for each point should be adjusted to match the state's policy priorities. If a state prioritizes to never fall short of the target, "Point A" should be right-shifted so that the sloping part of the demand curve can start at the target. If total cost is the main concern, the price at the cap can be lower than in the figure. If the state wishes to maximize the pace of decarbonization, the foot of the curve can extend to 105% of load even if the target begins at a low level. As long as the curve passes through the target quantity at a price near or above Clean Net CONE, the curve will help meet the clean energy objectives while appropriately balancing costs, mitigating price volatility, and supporting a sustainable marketplace.

HOW SUPPLY RESOURCES PARTICIPATE IN THE ICCM

Participating resources, both clean and emitting, participate in the ICCM by identifying their annual net going forward costs for delivering capacity and clean energy in the targeted delivery year (three years in the future). Offer prices for new resources will likely reflect annualized investment costs minus net energy and ancillary service market revenues, as all such resource costs could be 'avoided' if their resource were not selected through ICCM. For traditional resources, the offer price is the total payment needed to deliver their qualified quantity of unforced capacity (in UCAP MW, comparable to today's capacity market). In the case of clean resources, the sell offer will also include the number of clean energy MWh (denominated as CEACs, RECs, or ZECs) the clean resource is expected to produce during the delivery year. New clean suppliers would have the option of selecting a 7-12 year price lock-in on clean energy payments to promote efficient financing.[80]

A clean energy supply resource would be eligible to sell capacity, CEACs, or both products into the ICCM. Examples of bids would include:[81]

- **A new 100 MW (nameplate) onshore windfarm**, with a $76/kW-year installed capacity (ICAP) revenue requirement and a 30% annual capacity factor would expect to produce 262,800 MWh of clean electricity and 13 MW of unforced capacity. It would be eligible to sell 262,800 CEACs and 13 MW UCAP of capacity.
- **A new 100 MW (nameplate) solar facility,** with a $61/kW-year ICAP revenue requirement and a 15% annual capacity factor would expect to produce 131,400 MWh of clean electricity and 42 MW of unforced capacity. It would be eligible to sell 131,400 CEACs and 42 UCAP MW of capacity.
- **A new 100 MW (nameplate) gas-fired peaking resource**, with an $82/kW-year ICAP revenue requirement, would expect to produce 0 MWh of clean electricity and 95 MW of unforced capacity. It would be eligible to sell 0 CEACs and 95 UCAP MW of capacity.

80 Resources that acquire a price lock would have their clean energy contributions automatically credited for the duration of the price lock (*i.e.*, have their supply offered at zero in subsequent auctions during the price lock period).

81 The majority of the numbers in these examples are derived from PJM's August 2020 filing before the Federal Energy Regulatory Commission regarding MOPR levels for new resources. *See* *Re: PJM Interconnection, L.L.C, Docket Nos. EL19-58-003, Informational Filing with Indicative Values for Energy and Ancillary Services Offset*, August 19, 2020.

Each supply resource would select one of three different offer types, representing their offer of committed production in the delivery year, three years in the future:

- **Capacity-Only Offers** (in units of $/MW-day UCAP) would be submitted by fossil plants or demand response that can sell capacity but that cannot sell CEACs;
- **Bundled Capacity + Clean Energy Offers** (in units of total $/year revenue requirement to deliver the independently-specified volumes of capacity and clean energy), which would be offered by clean energy resources that seek to earn this total revenue requirement but that are indifferent as to whether the revenues are earned from capacity or clean energy payments; or
- **Clean-Energy-Only Offers** (in units of $/MWh of CEACs, RECs, or ZECs) would be offered by sellers that wish to market their clean energy sales independent of any capacity obligation. This offer type might be primarily relevant for clean energy resources that have failed to qualify for capacity sales, or market participants that hold excess volumes of unbundled CEACs that were procured bilaterally.

Each resource would compete to sell capacity and clean energy up to their maximum offered quantity. The auction clearing would account for each resource's eligibility to serve each LDA demand curve and fulfill each state's demand curve (as well as to meet any state resource carve outs that it is eligible to serve). Resources would clear to sell the highest-value products for which they are eligible and would be guaranteed to earn payments equal to or exceeding their offer price.

Once cleared in the forward auction, each supply resource would take on an obligation to deliver the cleared volume in the specified delivery year. Resources that produce excess volumes of clean energy attributes within the delivery year would be able to sell these excess volumes bilaterally, in a spot auction, or possibly bank the excess credits. Resources that produce an insufficient volume of clean energy relative to their commitment would be required to fulfill the obligation either through a bilateral purchase or a procurement within the final spot auction.[82]

C. ICCM with Clean Capacity Requirements

One of the design options of ICCM is to adopt consideration of "clean capacity requirements" that would advance not only the share of clean *energy* on the system, but also the share of *capacity* that would be served by clean energy resources. These requirements may be relevant, for example, if states want their reliability services provided by clean resources (such as storage, demand response, nuclear, and some existing hydro) that may not be eligible under REC or ZEC programs. Under a clean capacity requirement, the state would specify a share of the *capacity* product that must be met from clean capacity resources. The clean capacity requirement would likely be lower than the clean energy goal. For example, New Jersey's Energy Master Plan found that the least-cost decarbonization pathway included 84% clean energy by 2030, but only approximately 42% clean capacity over the same timeframe.[83] The remainder of capacity and other reliability needs would continue to be served by infrequently-operated fossil fuel plants that are maintained for the primary purpose of serving reliability and balancing needs.

The Brattle Group estimated the potential market outcomes within an ICCM design with three levels of clean capacity requirements, as summarized in Table 6. The three cases examined are: (i) a *High Clean Capacity Requirement* scenario, in which state mandates for clean energy are also applied as a mandate for clean capacity, the New Jersey 2030 clean capacity requirement is 84% (equal to the state renewable

[82] See additional discussion of arrangements for discussion of delivery obligations in Appendix D here.

[83] *See* State of New Jersey Energy Master Plan.

plus nuclear policy); (ii) a *Low Clean Capacity Requirement* scenario, in which the clean capacity requirement is half the size of the clean energy policy, or 42% in new Jersey by 2030, this scenario is approximately consistent with the Energy Master Plan; and (iii) a *Mid Clean Capacity Requirement,* which is half way between the other two.

TABLE 6: MINIMUM CLEAN CAPACITY REQUIREMENTS

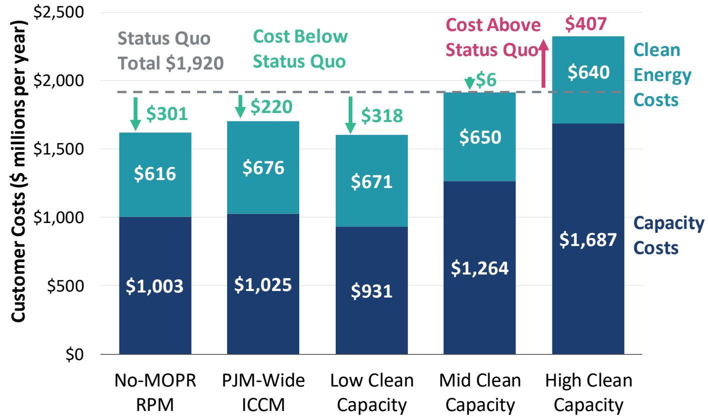
	Clean Energy (RPS + Nuke)	Total Clean Capacity Needed (Local + Imports)			Local Clean Capacity Needed		
		Low Clean Capacity	Mid Clean Capacity	High Clean Capacity	Low Clean Capacity	Mid Clean Capacity	High Clean Capacity
RTO	54%	27%	41%	54%	n/a	n/a	n/a
MAAC	68%	34%	51%	68%	32%	48%	65%
EMAAC	74%	37%	55%	74%	24%	35%	47%
NJ	84%	42%	63%	84%	n/a	n/a	n/a

Figure 19 summarizes the New Jersey customer cost and resource mix outcomes by 2030 under an ICCM with clean capacity requirements. As illustrated in the top panel, the ICCM with clean capacity requirements can produce customer costs ranging from $320 million per year in customer savings relative to the status quo, up to $400 million per year in additional costs above status quo. The figure further illustrates that an increasing share of New Jersey customers' capacity costs are directed toward clean capacity resources at higher clean capacity requirement levels.

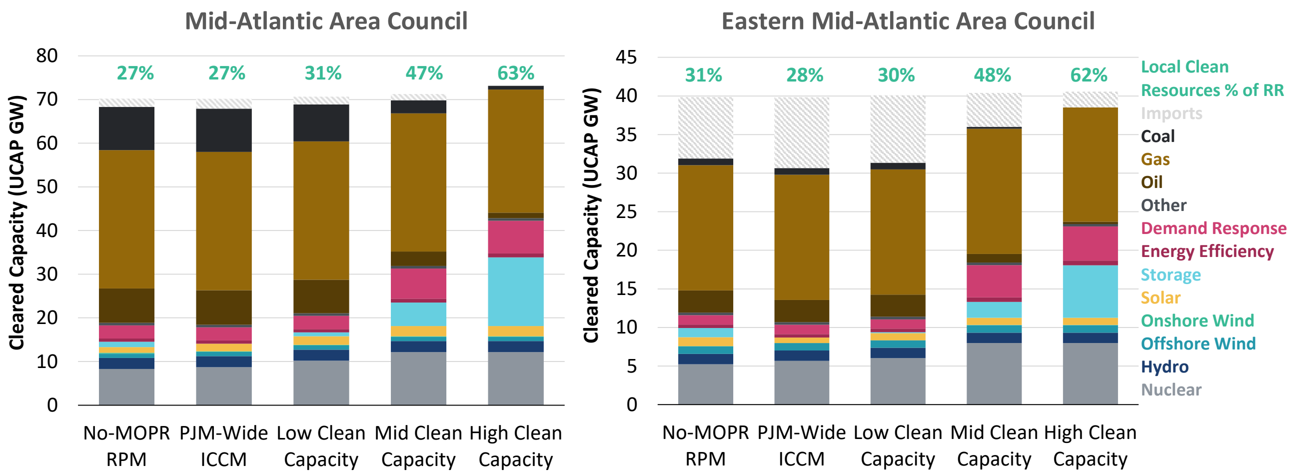
The bottom panel illustrates the resource mix under each of these alternatives, focusing on the MAAC and EMAAC regions serving New Jersey. In EMAAC, the share of clean capacity could increase from 28% (under a PJM-wide ICCM) up to 30-60% (under the range of clean capacity requirements modeled). The additional clean capacity comes primarily from at-risk nuclear that might otherwise retire, demand response, and storage. The additional clean capacity supply displaces fossil plants (primarily aging oil and coal plants) in EMAAC as well as the broader PJM footprint.

FIGURE 19: NEW JERSEY CUSTOMER COSTS AND SUPPLY MIX IN 2030 BY RESOURCE ADEQUACY DESIGN

PANEL A: NEW JERSEY CUSTOMER COSTS



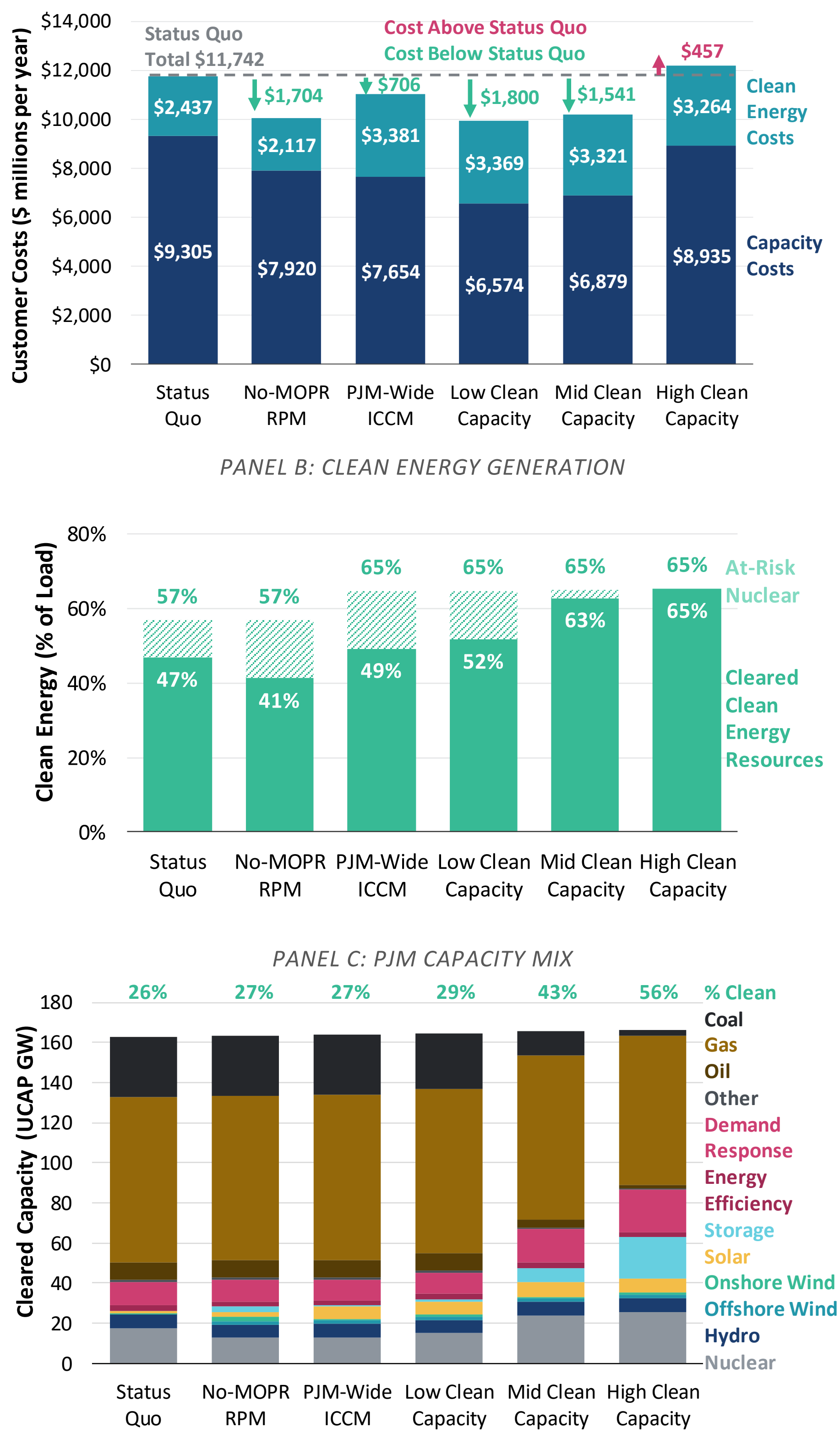
PANEL B: CAPACITY MIX IN THE EASTERN CAPACITY AREAS SERVING NEW JERSEY



On a PJM-wide basis, imposing clean capacity requirements would similarly shift investment incentives and the resource mix. At lower clean capacity requirements, total customer costs would drop by approximately $1,800 million per year compared to the status quo; the midpoint case would reduce costs by $1,550 million per year; while the highest level of clean capacity requirements could increase total customer costs by $450 million per year. On a PJM-wide basis, the total share of capacity needs met from clean energy resources would increase from 27% under ICCM, and up to 29-56% of the total PJM capacity mix depending on the size of the clean capacity requirement. The incremental clean capacity needs are fulfilled by at-risk nuclear that might otherwise retire (Figure 20B), demand response, and storage. The clean capacity requirements offer an opportunity to retain existing nuclear plants, even if they are not eligible to sell clean energy attributes to all states under the ICCM. Considering both increases in renewables and increases in retained nuclear, the ICCM with clean capacity constraints could advance PJM-wide clean energy from 41% (in the No-MOPR RPM) up to 52-65% of total PJM-wide demand. For demand response and storage, clean capacity requirements would maintain and advance their position as likely the most cost-effective means of providing reliability services in states that wish to achieve complete decarbonization of the supply mix. The incremental clean capacity resources encourage the retirement of aging fossil plants, primarily coal and oil (Figure 20C).

FIGURE 20: PJM-WIDE CUSTOMER COSTS AND SUPPLY MIX IN 2030 BY RESOURCE ADEQUACY DESIGN

PANEL A: CUSTOMER COSTS IN PJM



Document Content(s)

Exhibit A

Clarification of Written Testimony Submitted by Dr. Kathleen Spees and Dr. Samuel A. Newell,

The Brattle Group (Sept. 2021)

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection L.L.C.,	)	
	)	**Docket No. ER21-2582-000**
Revisions to Application of Minimum Offer Price Rule	)	
	)	

CLARIFICATION OF WRITTEN TESTIMONY

Submitted by

DR. KATHLEEN SPEES AND DR. SAMUEL A. NEWELL

Our names are Dr. Kathleen Spees and Dr. Samuel A. Newell. We are employed by The Brattle Group as Principals. We submit this clarification on behalf of the Natural Resource Defense Council, the Sustainable FERC Project, Earthjustice, Sierra Club, and Union of Concerned Scientists.

On August 20, 2021, we submitted into this docket written testimony on the Economic Impacts of the Expansive Minimum Offer Price Rule within the PJM Capacity Market ("August 20 MOPR-Ex Testimony").[1] On August 30, 2021 the PJM Power Providers Group ("P3") submitted a motion to strike ("P3 Motion") our testimony on the grounds that it relied "on confidential market information that parties in this adversarial proceeding cannot examine or challenge."[2]

In response to the P3 Motion, we offer the following clarifications of our August 20 MOPR-Ex Testimony:

- Our August 20 MOPR-Ex Testimony relied entirely on publicly available information, and
- The economic analysis and conclusions presented in our August 20 MOPR-Ex Testimony do not hinge on the precise magnitude of the economic impacts presented.

We provide a more comprehensive explanation of the basis for our economic analysis and conclusions as follows.

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[1] *See* Comments of Natural Resources Defense Council, Sustainable FERC Project, Sierra Club, and Union of Concerned Scientists, at Exhibit A, Docket No. ER21-2582 (Aug. 20, 2021), Accession No. 20210820-5241.
[2] *See* Motion to Strike of the PJM Power Providers Group (Aug. 30, 2021), Accession No. 20210830-5129.

A. Our August 20 MOPR-Ex Testimony Relied On Publicly Available Information

Our August 20 MOPR-Ex Testimony made reference to the results of a public study issued by the New Jersey Board of Public Utilities ("NJBPU Report") in June 2021.[3] The NJBPU Report was authored by NJBPU staff but made use of economic analysis and modeling estimates that we had conducted on their behalf over the timeframe spanning Fall 2020 through June 2021. The NJBPU Report reported an estimate that MOPR-Ex could cost PJM customers approximately $1.7 billion per year by 2030, along with a description of the assumptions and methods used to develop that estimate. The analysis contained within the NJBPU Report relied on many assumptions and data sources, one of which was a confidential dataset of PJM capacity market sell offers from the 2021/22 Base Residual Auction ("BRA") ("Confidential Offer Data").[4] Within the capacity market model utilized for the NJBPU Report, the Confidential Offer Data were used as the primary basis for developing the 2025 supply curve, and were used to a lesser extent as an input to the 2030 supply curve.[5] After concluding the economic analysis contained within NJBPU Report in June 2021, we have not accessed or used the Confidential Offer Data for any purpose.

The estimated costs to consumers reported on pages 26–30 in our August 20 MOPR-Ex Testimony were based solely on results reported in the publicly-available NJBPU Report.[6] Any other party to this proceeding or member of the public could have referenced this same information.

[3] *See* Staff of New Jersey Board of Public Utilities, Alternative Resource Adequacy Structures for New Jersey: Staff Report On The Investigation Of Resource Adequacy Alternatives, NJBPU Docket No. EO20030203 (June 2021), https://nj.gov/bpu/pdf/reports/NJ%20BPU%20RA%20Investigation%20(Final).pdf. In our August 20 MOPR-Ex Testimony, this report was cited extensively both by reference to the public website where it has been available since June 2021 and by including that report in full as attachment. *See* August 20 MOPR-Ex Testimony at n.12 and Attachment A.

[4] We understand that the Confidential Offer Data were provided by PJM to the New Jersey BPU under the terms of PJM Operating Agreement Section 18.17.4 regarding disclosure of data to authorized commissions. (*See* Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. Confidentiality Provisions (Rate Schedule FERC No. 24) at Section 18.17.4 ("PJM Operating Agreement"), https://www.pjm.com/directory/merged-tariffs/oa.pdf.) We also understand that, per the terms of the Operating Agreement, PJM issued a notification to all market participants on October 9, 2020, explaining the proposed transfer of the Confidential Offer Data. The notification stated that the data would be transferred to the NJBPU and any third party contractors that signed the requisite non-disclosure agreement ("NDA") contained within Schedule 10 of the Operating Agreement; the PJM notification further advised that the data would be used for the purpose of supporting the NJBPU investigation of resource adequacy alternatives. (See PJM Operating Agreement, Schedule 10; and NJBPU, Investigation of Resource Adequacy Alternatives, https://www.nj.gov/bpu/about/divisions/ferc/resourceadequacy.html (last visited Sept. 10, 2021)). Interested parties were offered seven days to object to the transfer of the Confidential Offer Data. We understand that no parties objected. PJM then transferred the Confidential Offer Data to the NJBPU. The NJBPU transferred the data to us as their contractors after we signed the requisite NDA (the full text of which is contained in Schedule 10 of the PJM Operating Agreement). Consistent with the public notification issued by PJM, we used the Confidential Offer Data as one input to the analysis we conducted for the NJBPU over the timeframe from Fall 2020 through June 2021.

[5] As described in the NJBPU Report, for the 2025 study year the 2021/22 BRA offer data were adjusted for expected retirements and new entry, and were adjusted to account for the effects of MOPR-Ex to develop the modeled supply curve. For the 2030 study year, the 2021/22 BRA offer data were further adjusted to account for additional entry of policy resources and offer prices were replaced with an estimate of the long-run avoidable net going forward costs of supplying capacity, which resulted in a more elastic supply curve (thus the 2030 supply curve would produce lower price and lower cost impacts from MOPR-Ex for the same volume of excluded policy resources). *See* NJBPU Report at 21.

[6] Every number, figure, and calculation contained within our August 20 MOPR-Ex Testimony makes clear reference to the public source of that information. We reiterate the sources of that information here for clarity. Customer cost impacts from MOPR-Ex are presented multiple times in the NJBPU Report in Section II.C, Appendix A, and Figure 20. Price impacts from MOPR-Ex are reported in the NJBPU Report on page 22. Increases in non-policy-resource capacity

The P3 Motion argues that FERC should not consider the results of the public NJBPU Report because parties to this proceeding cannot access the Confidential Offer Data used as an input to that study.[7]

While P3 is correct that the detailed Confidential Offer Data utilized within the NJBPU Report cannot be accessed by them or by us for the purposes of this proceeding, we disagree with P3's concern that the results of the NJBPU Report cannot be validated with public information. PJM does produce sufficient public data with which to confirm the findings of the NJBPU Report, including a smoothed version of the 2021/22 aggregate supply curve and a scenario analysis of price impacts from adding or subtracting various quantities of supply from the capacity auction.[8] In its scenario analysis of the 2021/22 BRA, PJM conducted two scenarios that can be used to validate the MOPR-Ex price impacts contained within the NJBPU Report: (a) Scenario 2 in which 3,000 unforced capacity ("UCAP") MW of supply was removed from the supply stack, causing a price increase of $21/MW-day; and (b) Scenario 4 in which 6,000 UCAP MW of supply was removed from the supply stack, causing a price increase of $33/MW-day.[9] Using linear interpolation between these two scenarios, one would estimate that excluding 3,500 MW of policy resources from clearing the market would cause a $23/MW-day increase in capacity prices—essentially the same as the $26/MW-day reported in the NJBPU Report in year 2025 from excluding 3,500 MW, based on more granular (confidential) data and modeling analysis.[10] In other words, one can utilize a very simplified analysis to estimate the price and cost impacts of MOPR-Ex (as in the simple linear interpolation just described) or a more sophisticated and detailed modeling approach (as is reported in the NJBPU Report), and arrive at nearly the same result.

B. The Economic Analysis and Conclusions Presented in Our August 20 MOPR-Ex Testimony Do Not Hinge on the Precise Magnitude of the Economic Impacts Estimated

We further clarify that the economic analysis and conclusions presented in our August 20 MOPR-Ex Testimony are primarily qualitative in nature and apply regardless of the precise magnitude of the results reported in the NJBPU Report. Our conclusions regarding the direction and nature of the impacts from MOPR-Ex are derived from qualitative inspection of the design using basic microeconomic

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revenues are identical to the increases in customer costs from MOPR-Ex, which are presented in NJBPU Report in Figure 16. Deadweight loss caused by MOPR-Ex was calculated as the product of average price and excess quantity as described in footnote 50 of our August 20 MOPR-Ex Testimony (this simplified calculation is an approximation of deadweight loss, given that the exact deadweight loss was not presented in the NJBPU Report). Net revenue increases to sellers was calculated as customer cost increases minus deadweight loss (again, this calculation is an approximation). The NJBPU Report and a March 19, 2021 draft of the same results (Kathleen Spees et al., *Alternative Resource Adequacy Structures for New Jersey: Draft Economic Impact Estimates*, Brattle (Mar. 19, 2021), https://www.nj.gov/bpu/pdf/ofrp/2021-03-11%20RA%20economic%20analysis%20results%20deck%20(1).pdf) presented a substantial amount of information that was not referenced in our August 20 MOPR-Ex Testimony.

[7] *See* P3 Motion, n. 4.

[8] *See* PJM Interconnection, 2021/2022 Base Residual Auction RTO Supply Curve (May 8, 2019), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-bra-supply-curves.ashx; and PJM Interconnection, Scenario Analysis for Base Residual Auction (Sept. 4, 2018), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-bra-scenario-analysis.ashx.

[9] The prices reported here are the unconstrained regional transmission organization ("RTO") prices; the PJM scenario analysis includes nine different scenarios of supply additions or supply reductions in different locations across PJM.

[10] The NJBPU Report estimate that 3,500 UCAP MW of policy resources would be excluded from the market was a product of modeling results, but could be just as easily determined from public information. The NJBPU Report reported the volume of resources subject to MOPR-Ex based on an analysis of public data on the growth in policy commitments to renewable, nuclear, and storage resources; of these resources only nuclear would have a low enough default MOPR-Ex price to clear the auction. *See* NJBPU Report at 19–21.

concepts.[11] Our qualitative economic analysis of MOPR-Ex predates the specific numerical findings reported in the NJBPU Report. For example, we have maintained a consistent economic analysis of MOPR-Ex across the following studies and publications:

- **An opinion piece that we contributed to *Utility Dive*** on January 27, 2020, in which we stated that MOPR-Ex would "prevent [policy resources] from clearing in the auctions and being paid for the capacity value they provide. It will increase the cost of clean-energy resources, hinder the industry's transformation to clean energy, and result in PJM committing more resources than what is needed for reliability, incurring unnecessary costs."[12]
- **A qualitative analysis of MOPR application to policy resources in the New York capacity market** conducted on behalf of the New York State Energy Research and Development Authority ("NYSERDA") and the New York State Department of Public Service ("NYSDPS") published May 19, 2020, in which we stated that "Applying [MOPR] to clean energy resources would inefficiently exclude them from the capacity market and produce the wrong capacity price… It would also induce a large transfer payment from customers to incumbent capacity suppliers; it also induces societal costs and deadweight loss. Applying [MOPR] would prevent clean resources from clearing the market and induce more non-policy-supported resources to clear, both existing and new ones. This would cause oversupply, retain excess fossil plants, and (in a worst case scenario) attract new fossil plants to enter the market."[13]
- **A quantitative analysis of MOPR application to policy resources in New York capacity market** published July 1, 2020, in which we estimated that applying an expansive MOPR to policy resources in that market would impose $1.8 billion per year in excess costs on New York consumers.[14] We note that our study of the costs of an expansive MOPR in New York used entirely different assumptions as consistent with the different features of that market, a different volume of affected resources, different market fundamentals, and a different modeling platform. That study used assumptions derived from the public domain to represent supply costs and offer prices. In that context, the estimated costs of an expansive MOPR are larger relative to the size of that market (primarily because the share of resources excluded by the MOPR would be larger). Despite these differences in study assumptions and results, the qualitative findings from that study were identical to those that we have offered in our August 20 MOPR-Ex Testimony.

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[11] *See* NJBPU Report; and Kathleen Spees, Travis Carless, Walter Graf, Sam Newell, et al., *Alternative Resource Adequacy Structures for Maryland: Review of the PJM Capacity Market and Options for Enhancing Alignment with Maryland's Clean Electricity Future*, prepared for Maryland Energy Administration (Mar. 2021), https://brattlefiles.blob.core.windows.net/files/21870_alternative_resource_adequacy_structures_for_maryland_-_review_of_the_pjm_capacity_market_and_options_for_enhancing_alignment_with_marylands_clean_electricity_future.pdf. Also included as Attachment E.

[12] *See* Sam Newell, Kathleen Spees, & Johannes Pfeifenberger, Forward Clean Energy Markets: A new solution to state-RTO conflicts, *Utility Dive* (Jan. 27, 2020), https://www.utilitydive.com/news/forward-clean-energy-markets-a-new-solution-to-state-rto-conflicts/571151/. Also included as Attachment A.

[13] *See* Kathleen Spees, Samuel Newell, & John Imon Pedtke, *Qualitative Analysis of Resource Adequacy Structures for New York*, at 5, prepared for NYSERDA and NYSDPS (May 19 2020), https://brattlefiles.blob.core.windows.net/files/18987_qualitative_analysis_of_resource_adequacy_structures_for_new_york.pdf. Also included as Attachment B.

[14] *See* Kathleen Spees, Sam Newell, John Imon Pedtke, & Mark Tracy, *Quantitative Analysis of Resource Adequacy Structures*, prepared for NYSERDA and NYSDPS, (July 1, 2020), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b9D20EBBD-4DF8-4E4E-BEC1-F4452345EBFA%7d. Also included as Attachment C.

- **A testimony we have submitted to the FERC** on November 18, 2020, including our economic assessment of expansive MOPR, including making reference to our economic analysis conducted on behalf of NYSERDA and NYSDPS.[15]
- **A study completed for the Maryland Energy Administration** in March 2021, in which we estimated that MOPR-Ex could impose $190–$240 million per year in costs on Maryland customers.[16]

Throughout all of these qualitative and quantitative analyses, our economic assessment of the impacts of applying MOPR to policy resources has remained the same. This is because the nature and direction of these impacts are obvious by inspection. Applying MOPR-Ex to policy resources can prevent them from clearing the capacity market. This produces higher prices, higher customer costs, excess total supply, and societal deadweight loss. One does not need a model or confidential information to draw these conclusions, one needs only to apply basic microeconomic concepts.

To estimate the magnitude of the cost impacts from MOPR-Ex, one must do a calculation. In the studies referenced above, we have taken great care to utilize the best available information to derive robust and defensible estimates of these cost impacts. At the same time, we have always acknowledged uncertainties related to the level of supply elasticity in the market, the volume of resources that would be excluded, and other assumptions. For example, in our assessment of cost impacts in New York, we conducted a sensitivity analysis that demonstrated a substantial uncertainty range of $1.3–$2.8 billion per year in customer costs that could be imposed by an expansive MOPR in that region depending on how many resources would be excluded and the prevailing market conditions.[17] Differences in these study assumptions can produce a different magnitude of estimated impacts, but in all cases the nature and direction of these economic impacts are the same (and always consistent with the outcomes predicted by standard microeconomic analysis).

In all cases, the estimates serve only to demonstrate the negative impacts of MOPR-Ex and the arguments for eliminating it; the specific level of the costs is not critical, as it would be with a damages calculation, for example. The conclusions do not hinge on the specific estimates, let alone the specific data on which the estimates were based.

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[15] *See* Kathleen Spees & Sam Newell, *The Economic Impacts of Buyer-Side Mitigation in New York ISO Capacity Market*, FERC Docket No. EL21-7-000 (Nov. 18, 2020), https://brattlefiles.blob.core.windows.net/files/20558_2020-11-18_the_brattle_group_ce_parties_protest.pdf. Also included as Attachment D.
[16] *See* Attachment E, Figure 14.
[17] *See* Attachment C at 5 and 8.

C. Certification

We hereby certify that we have read the filing signed and know its contents are true as stated to the best of our knowledge and belief. We possess full power and authority to sign this filing.

Respectfully Submitted,

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September 10, 2021

Attachment A

Samuel Newell, Kathleen Spees, & Johannes Pfeifenberger, *Forward Clean Energy Markets: A new solution to state-RTO conflicts*,

Utility Dive (Jan. 27, 2020)

UTILITY DIVE

OPINION

Forward Clean Energy Markets: A new solution to state-RTO conflicts

Published Jan. 27, 2020

By Sam Newell, Kathleen Spees and Johannes Pfeifenberger

The following is a contributed article by Sam Newell, Kathleen Spees, and Johannes Pfeifenberger of The Brattle Group.

The Federal Energy Regulatory Commission's recent order on PJM's Minimum Offer Price Rule (MOPR) will subject state-mandated or state-supported nuclear and renewable generation resources to offer-price floors in the PJM capacity auctions. This may prevent them from clearing in the auctions and being paid for the capacity value they provide. It will increase the cost of clean-energy resources, hinder the industry's transformation to clean energy, and result in PJM committing more resources than what is needed for reliability, incurring unnecessary costs.

The prospect of this outcome has already forced states, consumer groups and environmental groups to contemplate exiting organized capacity markets, for example, by means of PJM's Fixed Resource Requirement (FRR) option.

That would be a loss. The capacity markets have historically provided economic efficiencies in meeting resource adequacy requirements at surprisingly low prices through broad participation, intense competition, and the ability to complement resources' other value streams in a largely technology-neutral design. Defections from the organized capacity markets would harm customers and competitive producers alike. Customers would lose the benefits associated with meeting capacity needs at low prices; competitive producers would likely face a dwindling organized market size, low prices, and the eventual elimination of the merchant business model.

These disappointing outcomes could be avoided if the markets were set up to complement clean-energy policies rather than reject them.

This could be achieved by adding carbon pricing and/or competitive clean energy attributes to the current suite of unbundled wholesale electricity markets for energy, ancillary services and capacity. Under this more comprehensive suite of wholesale markets, capacity markets can recognize clean resources' environmental value stream as a legitimate offset to the net cost of providing capacity — similar to the way capacity markets already recognize energy and ancillary services offsets. The result would be a more comprehensive and robust wholesale market design that can meet all reliability needs and policy goals at the attractive low prices we have come to expect from competitive markets.

Carbon pricing

Carbon pricing is often advocated as the purest solution that would internalize carbon policy objectives directly into the market so that the market can identify the least-cost sources of carbon emission abatement and most reward those that displace the most emissions. We agree that adding carbon pricing to organized wholesale power markets should be pursued, whether through carbon taxes, carbon charges or cap-and-trade. To achieve the most economic outcome, carbon prices would ideally be set at the ascribed value of carbon abatement consistent with policy goals, applied uniformly across a broad multi-state or national footprint, applied uniformly across all economic sectors, not just electricity.

Realistically, though, the federal government is not close to implementing any carbon pricing, and few states are considering imposing carbon prices that are high enough to meet their goals. Achieving a uniform and appropriately high carbon price across both jurisdictions and economic sectors is unlikely in the near term. And a patchwork of different prices across states can create "leakage" by increasing the output of carbon-emitting resources from outside the carbon-pricing region, absent border adjustments as proposed by the New York Independent System Operator, but not yet addressed by the Regional Greenhouse Gas Initiative (RGGI). Further, depending on the policy environment, carbon prices can sometimes be perceived by investors as having too much "stroke of the pen" risk to support major investments.

Forward Clean Energy Market

This is why, even with some carbon pricing, investment in clean energy sufficient to meet state and customer preferences will likely continue to rely on payments for clean energy attributes that durably recognize their policy value. With that in mind, we have developed the concept of a Forward Clean Energy Market (FCEM) that would competitively procure clean energy commitments in a technology-neutral fashion that can complement other wholesale power market products, including capacity.

The FCEM could be administered by an individual state, an existing market operator (such as PJM) or an interstate entity (such as RGGI). The FCEM would procure Clean Energy Attribute Credits (CEACs), a product similar to RECs but drawing on best practices and experience with modern market design. The FCEM:

- Qualifies a broad set of resources and technologies to maximize competition;
- Uses a three-year forward procurement to allow for competition between existing and new resources and provide more certainty in market revenues;
- Incorporates a downward-sloping curve for aggregate demand from both state mandates and green energy demands of retail customers, buying more CEACs and accelerating the transition to clean energy when they are cheap (and buy less when not), to reduce price volatility, and mitigate market power;
- Uses uniform-price auctions to encourage cost-based offers, transparently award winners at competitive prices, and attract innovative solutions and low-cost technologies to enter the market;
- Offers a multi-year price lock-in to support the financing of new resources;
- Offers advanced features to dynamically vary payment rates for CEACs based on the realized carbon abatement at any point in time and avoid negative-priced energy offers; and
- Avoids the need for border adjustments in carbon pricing regimes to prevent the "leakage" of carbon emissions.

Avoiding MOPR's inefficiencies

Adopting an FCEM can avoid the inefficiencies of imposing MOPR on clean-energy resources, by recognizing the in-market payments for environmental attributes that would otherwise be excluded from organized wholesale electricity markets. The CEAC products would more effectively complement the grid services that are rewarded in organized markets through the existing energy, ancillary and capacity products.

With the introduction of an FCEM, no special MOPR treatment of clean energy resources would be needed or be appropriate because it would be clear that CEAC payments are a competitive means of meeting clean energy goals. It would be clear that the FCEM procurement would in no way be associated with any intention to suppress capacity prices paid to conventional resources, or to do anything other than internalize environmental externalities, just like carbon pricing.

FCEM and capacity markets can also incorporate technology-specific carve-outs for targeted resource types, such as offshore wind, to meet special policies aimed at advancing R&D and commercialization. MOPR should not apply to such resources either: with any premium representing a down payment on future cost declines, they should not be considered "uneconomic" (per the original MOPR). Moreover, as long as they also qualify for the base product toward meeting the state's overall clean energy objective, they are displacing base resources and effecting little or no net impact on capacity prices.

Avoiding a painful transition to less cost-effective constructs

Why bother with all this? If implementing a broad MOPR denies clean energy resources access to wholesale capacity markets for the resource adequacy benefits they provide, the affected states may simply leave the PJM capacity market. States could force load serving entities or integrated utilities into PJM's Fixed Resource Requirement option, such that they have to contract bilaterally for capacity; or states might even consider reverting to partial or full re-regulation of all capacity resources. This could involve a costly and painful transition to less competitive and less cost-effective market and regulatory constructs.

Compare bilateral contracting and RFPs to multilateral organized markets with multiple products: the competitive scope of an RFP for, say, wind generation is only new wind plants. In contrast, the scope of competition in organized product markets is much wider as all technologies (and both existing and new plants) are forced to compete. In addition, the shorter price lock-in (contracting period) and unbundled product-specific procurement (energy, ancillary services, capacity and CEACs) leave more of the market, technology and financing risks with the bidders and project developers, who are in a better position to assess, control and mitigate these risks than retail customers. In contrast, the 10-20 year contracts for specific new resources leave much more of these risks with customers, including plant-specific risks.

Read More in **Regulation & Policy**

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LA approve energy by 2 decade ahe
Sep 02, 202

Our hope is to see a future in which organized wholesale power markets will continue providing the now-well-documented benefits of: (1) optimizing reliable grid operations at low cost; (2) attracting investments at low cost; and (3) keeping more investment risks with suppliers, rather than customers. To achieve that outcome, we believe the organized markets will have to offer state policymakers and customers a market design that aligns with and can help achieve their clean energy goals. The FCEM and carbon pricing offer that solution.

Alongside the traditional energy, ancillary services and capacity markets, the FCEM can help signal when any particular attribute is valuable or scarce and which resources and technologies provide the best bundle of multi-attribute values to meet overall system needs — whether the supply is coming from conventional, renewable, nuclear, storage, demand response or interchanges. Such well-designed, unbundled product markets are the most economically efficient path to solving the challenging problem of decarbonizing the electricity industry while keeping the lights on.

FERC's order does not provide an easy path for making all of this work, particularly for reconciling state clean energy policies with organized wholesale capacity market participation. Nevertheless, we are hopeful that, even with FERC's order, FCEM is different enough and sensible enough that it can offer a workable path forward.

Attachment B

Kathleen Spees, Samuel Newell, & John Imon Pedtke, *Qualitative Analysis of Resource Adequacy Structures for New York*,

The Brattle Group (May 19, 2020)

Qualitative Analysis of Resource Adequacy Structures for New York

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May 19, 2020

THE Brattle GROUP

Contents

Introduction

In recent years, there has been concern regarding a growing disconnect between wholesale markets and states' clean energy and environmental goals. In many cases, this concern has stimulated a constructive dialogue on how reliability needs can be better expressed through wholesale markets with a changing fleet, how markets can help states to achieve their clean energy goals at the least cost, and how state programs can be aligned with the merchant investment model.[1,2]

Compatibility concerns have been elevated by recent efforts of the Federal Energy Regulatory Commission (FERC) to impose Buyer Side Mitigation (BSM) or Minimum Offer Price Rule (MOPR) provisions on state-sponsored clean energy resources.

To address the inconsistency of BSM rules and New York's clean energy goals, New York policymakers are working to identify and evaluate alternative approaches to meeting resource adequacy needs in an ongoing docket before the Public Service Commission (PSC).[3] To assist in this evaluation, we offer our independent assessment of a range of options for addressing resource adequacy, which are summarized in Table 1.

1 As a few examples of studies and efforts to better align markets with states' policy needs, see proceedings under the New England Integrating Markets and Public Policy Initiative, one of our papers on aligning markets with environmental policy, and Energy Innovation's paper series on options for improved market-policy alignment.

2 In this paper, the term "merchant investment" refers to resources whose energy and capacity are not contracted to captive customers.

3 PSC Case 19-E-0530, "Proceeding on Motion of the Commission to Consider Resource Adequacy Matters."

Table 1
Resource Adequacy Structures to Evaluate

Structure	How is Resource Adequacy Achieved
1. ICAP Market with Status Quo BSM	• ICAP procurement market administered by NYISO • Administratively set demand curve consistent with 1-in-10 reliability standard • Supply-side offers provide capacity as per intersection with the demand curve • Status quo BSM rules (no blanket exemptions in place for Storage or Clean Resources in G-J) • Bilateral contracts enabled between Load-Serving Entitites (LSEs) and capacity sellers, but subject to BSM
2. ICAP Market with Expanded BSM	• Resource adequacy procurement administered by NYISO same as in Structure 1 • Expanded BSM rules cover some existing resources including policy-supported nuclear, all new clean energy, and contracted storage resources (consistent with FERC's recent MOPR Order for PJM) throughout NYCA • Bilateral contracts enabled between LSEs and capacity sellers, but subject to BSM
3. Centralized RAC Market without BSM	• Resource adequacy procurement functionally similar to Structure 1, but rule-setting would be taken on by the State. To achieve that outcome, the State may need to take on all auction and administrative functions (or some responsibilities may be shared by the State and NYISO) • New York Resource Adequacy Credits (RACs) would satisfy LSE reliability obligations, similar to the role ICAP/UCAP plays in Structures 1 and 2 • Bilateral contracts enabled between LSEs and capacity sellers • No BSM except as applied by PSC on a case-by-case basis to prevent the intentional introduction of uneconomic capacity to profitably suppress capacity market prices
4. LSE Contracting for RACs	• LSEs would be responsible for procuring through contracts sufficient RACs to meet resource adequacy obligations (fixed obligations, not on a demand curve) • No centralized procurement (no centralized auction; no administrative demand curve) • No BSM except as applied by PSC on a case-by-case basis to prevent the intentional introduction of uneconomic capacity to profitably suppress capacity market prices
5. Co-optimized Capacity and Clean Energy Procurement	• Same as Structure 3, except a State entity would procure both RACs and RECs for LSEs in a joint, co-optimized auction • To offer clean energy investors more forward visibility and certainty, the forward period could be extended to 3-years forward, and the term of RECs awarded under the auction may be 7-20 years for new resources (procurements of RECs for existing resources and RAC commitments would secured on a year-by-year basis) • Bilateral contracts enabled between LSEs and RAC sellers • No BSM except as applied by PSC on a case-by-case basis to prevent the intentional introduction of uneconomic capacity to profitably suppress capacity market prices

We evaluate these structures by first addressing the foundational questions of why we view the application of BSM to environmental policy-supported resources as economically flawed. We then provide a more detailed description of the mechanics of each structure and a qualitiative analysis of each one's advantages and disadvantages.

As an overall matter, we view the automatic imposition of BSM on clean energy resources as costly and problematic, with the scope of the challenges growing alongside the scope of covered resources.[4]

Structure 1: ICAP Market with Status Quo BSM is less problematic than *Structure 2: ICAP Market with Expanded BSM* primarily due to the less extensive scope of mitigation. The remaining structures entirely avoid BSM for policy-supported resources, but with significant differences in approach and relative merits. As an overview of the relative merits:

- *Structure 3: Centralized RAC Market without BSM* has significant merits, maintaining the economic and competitive advantages of the current ICAP market to harness competitive forces toward meeting resource adequacy needs cost effectively. It would also provide market continuity, as it relies on a centralized structure similar to the one market to which players have become accustomed. Certain implementation functions may be able to remain with NYISO even as a state agency takes on responsibility for implementing auction procurements.
- *Structure 4: LSE Contracting for RACs* may necessitate the development of approaches for mitigating certain disadvantages of bilateral resource adequacy markets, particularly their lower price transparency and reduced ability to address market power concerns.
- *Structure 5: Co-Optimized Resource Adequacy and Clean Energy Procurement* would offer largely the same benefits as Structure 3, with the additional opportunity to achieve lower total system costs through a procurement mechanism designed to jointly procure the least cost supply to meet both capacity and clean energy needs. This approach would require significant time and policy attention to develop a sound procurement design aligning with best practices, given that there are limited examples to draw upon. This approach, if pursued, could naturally extend or evolve from *Structure 3: Centralized RAC Market without BSM*, but could be more complex and time-consuming to implement on a near term time horizon.

We provide a more comprehensive discussion of the approaches, advantages, and disadvantages of these five structural choices in the body of this qualitative assessment. In a separate work product, we present quantitative estimates of the anticipated cost impacts of Structures 1, 2 and 3 in the year 2030; quantitative estimates of Structures 4 and 5 were beyond project scope.

As a complement to any of the above approaches, enhancing the E&AS with higher scarcity pricing could be separately pursued at the NYISO. The advantages of this parallel improvement would be to offer a more accurate representation of when and where reliability is needed as compared to the

[4] We do see an economic rationale for MOPR, or other market power mitigation approaches, if used for the narrower original purpose for discouraging the intentional introduction of uneconomic capacity for the purposes of profitably suppressing capacity market prices (whether by net-short buyers or by state agencies on behalf of customers). However, state clean energy policy resources are not there for that purpose (and would be an inefficient way to suppress prices) but rather to meet long-term clean energy mandates.

more "blunt instrument" of relying heavily on the current ICAP market or RACs. If properly designed, this would tend to shift money out of the resource adequacy construct and into the E&AS markets, where reliability can be more precisely measured. This would also shift the resource mix toward those providing more operational flexibility and resulting reliability.

I. Economic Assessment of the Rationale for BSM Application to Clean Energy Resources

The rationale for expanding BSM is grounded in flawed economic logic, but has gained significant traction in recent years among incumbent capacity market suppliers, some market advocates, and (most recently) with the majority of the FERC ("BSM advocates"). The stated concerns are as follows.

States such as New York are attracting large quantities of new resources to meet clean energy goals through a variety of programs and contract solicitations that BSM advocates consider to be "subsidies."[5] Because these activities can reduce near-term capacity market prices and/or displace "non-subsidized" resources, BSM advocates argue that it is necessary to protect wholesale capacity markets from the price-suppressive impacts of state policies. The assertion is that the capacity price should be restored to the "correct" price*, i.e.*, the price that would have prevailed in the absence of the state policies.

In our view, however, clean energy policies and resources address an environmental externality that must be incorporated into resource investment decisions in order to achieve economic efficiency. The clean resources provide valuable clean energy attributes that fossil resources do not provide, such that their net cost of capacity may be lower (similar to resources providing high energy and ancillary services value). If the capacity market produces low prices, this is correctly signaling an oversupply of capacity, that no more investments are needed for resource adequacy, and the least valuable resources should retire. Reliability would not be threatened, as clean resources could be credited only with the marginal reliability value they actually provide (through reliability studies that recognize the declining marginal value of intermittent resources and storage as penetration increases). Any potential shortages would increase capacity prices if and only if needed to attract and retain capacity as needed to maintain resource adequacy.

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5 We do not subscribe to the view that such state programs and/or solicitations should always be considered "subsidies" in the traditional sense, nor that subsidies are inappropriate or inherently problematic if they are pursued in light of policy goals. Instead, we see the introduction of clean energy policies as generally providing compensation for environmental externalities not otherwise provided for.

We do see some merit in one aspect of some BSM advocates' arguments: that the prevalence of contracting for new resources seems to depart from the state's market/regulatory model, whereby the investment risk of most generation resources was placed on suppliers facing organized wholesale market prices for energy and capacity rather than contracts with captive load.[6] Relying on contracts shifts some risks back to customers. Customers become exposed to the risk that state-sponsored technology-specific mandates and procurements do not select the most cost-effective resource mix. These risks exist, even if procurements employ competitive solicitations and careful selection of resources with different characteristics, generation profiles, and locations.

The BSM advocates argue that a better way to address environmental externalities would be to express them through a carbon pricing mechanism. This would enable all resources to compete based on market prices for energy (that price in carbon), capacity, and ancillary services; it would efficiently disfavor emitting resources and support investment in clean resources possibly without the need for additional payments or contracts.

We too believe that carbon pricing could help support the state's objectives cost-effectively, through resource-neutral competition that signals where and when clean energy production displaces the most carbon emissions. We have stated this in numerous forums, where we have also addressed how to mitigate leakage to other geographies and sectors and associated economic distortions. However, carbon prices alone may not be high enough, or be perceived by investors as being politically stable enough, to support sufficient merchant investment to meet state policy targets—especially as the target tightens toward zero. Some form of customer-backed long-term contracts for clean energy attributes can solidify the support and efficiently transfer the regulatory risk away from suppliers, while still leaving some market risk with them. Unfortunately, resources receiving such support would likely continue to be subject to mitigation under the existing approach, even with carbon pricing in place.

Applying BSM to clean energy resources would inefficiently exclude them from the capacity market and produce the wrong capacity price, as noted above. It would also induce a large transfer payment from customers to incumbent capacity suppliers; it also induces societal costs and deadweight loss. Applying BSM would prevent clean resources from clearing the market and induce more non-policy-supported resources to clear, both existing and new ones. This would cause oversupply, retain excess fossil plants, and (in a worst case scenario) attract new fossil plants to enter the market. These outcomes would be counterproductive from a policy perspective, inducing excess customer costs from unnecessarily high capacity prices, inflating the costs of clean energy contracts, and potentially driving private capital to invest in fossil plants that will not be needed. The scale of these problems would grow with the scope of BSM application (as we will separately evaluate in our quantitative analysis).

To mitigate such outcomes from BSM, a number of ISOs and market participants have proposed or implemented convoluted solutions. These include the ISO-NE's Competitive Auctions with

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6 This has not been the case for resources owned by or contracted to power authorities, such as NYPA and LIPA.

Sponsored Policy Resources (CASPR), which FERC has approved; PJM's Resource-specific Carve Out (ReCO), which was not approved; and some of the options discussed in the PSC docket.[7] In general, we see these proposals as overly complicated, economically flawed, and ultimately unsatisfying. The central problem is that they are designed to answer the wrong question of how to "correct" prices to a higher level without introducing economic inefficiencies. These proposals will always cause inefficiencies as long as they signal the market at prices that deviate from the underlying fundamentals of supply (including that associated with state policy resources) and demand (as expressed through resource adequacy requirements).

The rest of this paper evaluates resource adequacy constructs that include BSM versus several alternatives that do not. Those without BSM appropriately count the resource adequacy value that clean energy resources provide, while also aiming to retain the benefits of competition in various ways and to various degrees.

II. Description and Evaluation of Alternative RA Structures

A wide range of approaches exist for meeting resource adequacy needs and have been tested across the globe for the past two decades or more, offering a rich literature of academic and industry studies on lessons learned across a variety of contexts.[8] We draw extensively on the lessons learned from both this literature and real-world experience as we assess the options for New York to meet resource adequacy needs over the coming decades, including:

Structure 1: "Status Quo" Installed Capacity Market
Structure 2: ICAP Market with Expanded BSM
Structure 3: Centralized RAC Market without BSM
Structure 4: LSE Procurement of Resource Adequacy Credits
Structure 5: Co-optimized Resource Adequacy and Clean Energy Procurement

In each case, we briefly describe the mechanics of how the design could work in New York, key design variations that the State may wish to consider, and relative advantages/disadvantages of each option.

7 ISO New England Inc., FERC Docket No. ER18-619-000. PJM Interconnection, L.L.C, FERC Docket No. ER18-1314-000. PSC Case 19-E-0530, "Proceeding on Motion of the Commission to Consider Resource Adequacy Matters."

8 As one example, see an international review of alternative approaches to achieving resource adequacy.

A. Structure 1: ICAP Market with "Status Quo" Buyer-Side Mitigation

How Does it Work?

The status quo approach to maintaining resource adequacy is a continuation of the current ICAP market to achieve resource adequacy. The current ICAP market relies on a combination of LSE self-supply and a non-forward centralized spot market to procure at least the minimum quantity of capacity needed to meet system and locational resource adequacy needs, as follows:

- The New York State Reliability Council (NYSRC), in coordination with the NYISO, establishes the quantity of capacity supply that must be procured on a system-wide and locational basis in order to meet the long-standing 1-in-10 reliability requirement. The quantity needed is first established on an ICAP basis as a reserve margin above peak load, and translated into the units of UCAP MW that must be secured from supply resources.
- The NYISO oversees the qualification of supply resources that are eligible to meet system and local capacity needs, determining the UCAP of supply each resource is eligible to sell in the summer and winter seasons within each capacity market zone.
- The obligation to meet the defined capacity obligation is imposed on each customer's LSE in proportion to that customer's realized contributions to system or local peak load. Each LSE has the flexibility to determine how they will meet the resource adequacy obligation through some combination of self-supply, forward bilateral contracting, voluntary participation in NYISO auctions, or reliance on the final mandatory spot auction.[9] NYISO enables bilateral transactions of the fungible UCAP capacity product to facilitate trade.
- To support and enforce LSEs' ability to fulfill the resource adequacy obligation, NYISO conducts a series of auctions for each delivery year including: (a) voluntary forward 6-month *strip auctions* for UCAP; (b) voluntary *monthly auctions* conducted 1 to 6 months forward; and (c) mandatory non-forward monthly spot auctions that all LSEs and resources must participate in to resolve any remaining shortfalls relative to the capacity obligation and ensure all supply is offered for sale.
- The mandatory final spot auction incorporates an administratively-constructed, downward-sloping demand curve and determines the final quantity of capacity procured (with a small bias toward over-procurement to limit the likelihood of falling short of the 1-in-10 requirement). The effect of the demand curve is to limit price volatility, gradually reduce the price as the quantity of capacity exceeds that required for resource adequacy, and manage quantity uncertainty in both the spot auction, and forward transactions that are informed by anticipated spot auction prices.

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9 However, BSM rules can prevent LSEs from using self-supply or bilaterally-contracted new resources, by subjecting them to mitigation and imposing a prohibitive risk that they not clear.

A variation of this capacity auction design has supported resource adequacy in New York for approximately two decades.[10] The ICAP market relies on a competitive model of attracting investments and retaining supply, in which private parties may respond to competitive pricing signals to enter the market when supply is tight (and prices are high) or exit the market when supply is long (and prices are low).

The current ICAP market incorporates BSM rules that were originally developed for the more limited and narrow purpose of preventing the exercise of market power for intentional price suppression. The concept was to mitigate the incentive and ability of a large buyer or State actor from developing excess supply at uneconomical costs relative to prices in order to suppress capacity market prices and benefit a large net load position. Historically, the BSM rules have excluded some State-contracted capacity supply from capacity market clearing but the effect has been limited by the limitation of applicability to the Zone G-J and NYC localities; by the ability to qualify for an economic or competitive entry exemption; and by the limited number of power plants under state contract.[11] Most resources entering the market have qualified for the relevant exemptions, for example with four resources being tested and exempted in the 2017 class year.[12]

Looking forward, it appears that BSM rules will be applied to an increasing amount of resources over time. On February 20, 2020, FERC issued several orders in which it: (i) denied a Complaint seeking to exempt energy storage resources from the NYISO's BSM rules; (ii) reversed its prior determination granting an exemption from BSM for demand response resources (referred to as Special Case Resources); and, (iii) rejected the NYISO's initial compliance filing that included a 1,000 MW cap on renewable resources that can qualify for such exemption in a single Class Year and directed the NYISO to file a further compliance filing.[13] The NYISO subsequently made a compliance filing that would use a formulaic approach to determining the capacity subject to the renewables exemption for each Class Year.

Based on these rulings, it is unclear which new resources developed in Zones G-J to meet the Climate Leadership and Community Protection Act (CLCPA) requirements would be subject to BSM, including: offshore wind (OSW); new renewables developed under index renewable energy credit (REC) contracts; storage; and Canadian hydro that could be contracted and delivered to Zone J through the Champlain Hudson Power Express (CHPE) or other similar arrangements, depending on contract terms. Some of these resources could be covered by the NYISO's proposed renewables exemption if approved by FERC. In our separate quantitative analysis of the potential cost of these (evolving) BSM rules, we assume in "Structure 1: 'Status Quo' ICAP Market" that BSM applies to

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10 Prior to that, the New York Power Pool relied on generator ownership and bilateral contracting to maintain Resource Adequacy.

11 NYISO, "Buyer Side Mitigation: Overview," July 26, 2019.

12 Potomac Economics, "Assessment of the Buyer-Side Mitigation Exemption Tests for the Class Year 2017 Projects," July 2019.

13 See FERC Docket Nos. EL19-86 (rejecting energy storage complaint), EL16-92 and ER17-996 (making rulings on Special Case Resources), and ER16-1404 (rejecting NYISO's compliance filing on renewables exemption and directing further compliance filing).

all CLPCA-related resources in Zones G-J, with only a single 1,000 MW exemption for "Class Year 2019" contracts.

In addition, the FERC did not address some parties' call for expanding BSM to the entire state, leaving this issue unresolved. We address that possibility separately, through "Structure 2: ICAP Market with Expanded BSM" in which BSM further applies to Upstate nuclear plants, new renewable and storage resources, and some existing hydro assumed to need capital expenditures.

What Are the Primary Design and Implementation Choices?

Continuing the status quo would require relatively few design and implementation choices to consider within the ICAP market itself. The primary questions facing the State, if pursuing this route, concern the proposed market design changes and regulatory avenues that could be pursued to limit the scope and impact of BSM (to avoid duplication, see our discussion of options under *Structure 2: ICAP Market with Expanded BSM*).

What Are the Primary Advantages?

The primary advantages of *Structure 1: ICAP Market with Status Quo BSM* include:

- Least effort to design and refine.
- Continued use of a time-tested ICAP market design and structures that have been proven to reliably meet capacity needs at competitive prices across a wide range of market conditions. The ICAP market will have either a minimal role or no role in guiding investment decisions for contracted resources, but will continue to perform the primary role of managing orderly fossil retirements and attracting/retaining other resources.

What are the Primary Disadvantages?

The primary disadvantages of *Structure 1: ICAP Market with Status Quo BSM* include:

- Inefficiency and excess customer costs will be driven by BSM (the scope of which will scale with the quantity of resources subject to BSM). Inefficiencies will manifest as excess quantities of capacity supply and delayed retirement of uneconomic fossil plants in zones G-J. Customers essentially have to "pay twice" for the capacity of mitigated resources.
- Requires significant effort to influence NYISO proposals, FERC decisions, and appeals processes in a way that reduces the applicability and impact of BSM without any guarantee of success.
- Ongoing and outstanding risk that FERC decisions could continue to expand BSM over time, with long-term outcomes becoming more similar to those discussed under *Structure 2: ICAP Market with Expanded BSM*.
- As BSM rules become more complex and less predictable, it would increase regulatory risks imposed on merchant resources and developers exposed to the wholesale capacity price. The costs of these risks will be borne, ultimately, by consumers.

B. Structure 2: ICAP Market with Expanded Buyer-Side Mitigation

How Does it Work?

Structure 2: ICAP Market with Expanded BSM is identical to *Structure 1: ICAP Market with Status Quo BSM* with the one exception that a broad BSM would be applied to all new and most existing contracted and policy-supported resources. This model is presumed consistent with the recent FERC ruling in PJM's MOPR docket and represents a worst-case scenario on the impact of BSM to inflate customer and societal costs.[14]

Directionally, the impacts of the expanded BSM are the same as those under Structure 1, but the much broader application would greatly expand the scale of impacts. These impacts would include:

- Application of BSM to most clean energy resources in New York including: resources across the entire footprint (not just in currently-mitigated capacity zones), all new contracts under the PSC's Clean Energy Standard (CES) for OSW and Tier 1 renewables, contracted storage, resources earning Tier 2 maintenance payments, nuclear resources earning Zero Emissions Credits (ZECs), contracted Canadian hydro imports, and distributed resources that are acting on the supply side of the capacity market and earn any "policy payments." This could eventually cover essentially all clean resources in the New York system, with some possible exceptions: existing renewables whose interconnection agreements were finalized prior to the Order date, existing large and small hydro that may not earn any policy payments, existing demand response, any new demand response and storage resources that pass mitigation tests, and any distributed resources which have no commercial interaction with the NYISO and, thus, are treated as demand reductions in the capacity market. Incumbent fossil resources without any state contracts also would not be subject to the BSM.
- Failure to clear large fractions of the BSM resources in the capacity market. Some BSM resources may still clear the market if they have low going-forward costs as measured under the approved BSM calculations. Some resources may clear even if subject to BSM due to low or medium BSM mitigated price levels (namely existing resources, some nuclear resources, demand response, and potentially storage if resource costs continue to decline). However, based on the indicative MOPR prices in PJM and New England we would expect few (if any) new/contracted clean energy resources to clear.
- Excess customer costs associated with: 1) double-payment for the capacity of the clean resources, and 2) inflated capacity prices, both of which are addressed in our quantitative analysis
  - The double-payment effect arises from having to pay once through the clean energy contracts that do not clear the capacity auction, then again for duplicate capacity that

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14 FERC Docket No. EL16-49-000, EL18-178-000.

does clear. The double-payment applies to the derated capacity value of the clean resources. As more wind and solar resources are added in the future, the applicable capacity would increase, albeit less than linearly as the marginal resource adequacy value of such resources declines with penetration.

  – The inflated capacity price effect arises from raising the offer prices of the mitigated capacity, likely pricing them out of the market, and causing the market to clear at a higher price on the demand curve. The price increase represents a wealth transfer from customers to capacity providers. Even a small increase can cause a large transfer since it applies to the entire quantity of capacity procured in the market.[15] The effect may be moderated in the long-term by the elasticity of supply.

- Retention of an excess quantity of existing fossil plants by the high capacity prices for many more years than would otherwise make sense in a deeply decarbonizing system. This would result in large quantities of excess capacity supply in the system (only the fossil plants being counted in the ICAP market, with clean capacity excluded and not clearing). The excess costs of keeping these low-capacity-factor resources online would be borne by customers via high capacity prices.
- Possible inefficient incremental investment in fossil plants due to the exclusion of clean energy resources from clearing the capacity auction. We note that this possible outcome is most likely only in a scenario with very tight system or locational supply demand balance as could be induced by a combination of rapid electrification-driven load growth, moderate levels of distributed resource development, significant fossil retirements (and lack of clean supply entry) in import-constrained zones. Our preliminary analysis of the New York system indicates that postponed fossil retirements is likely, thus inducing inefficient re-investments in ongoing fixed costs and repowering. However, our analysis suggests that the potential to induce incremental investments in new fossil resources is relatively unlikely.
- Inflation of capacity prices and policy contract prices through the imposition of excess regulatory risks on the market. Note that if any merchant storage resources do enter the market on a fully merchant basis, they may be willing to do so only at high prices above their levelized net cost of new entry (Net CONE). This reluctance to invest may come about as investors will doubt the sustainability of high capacity prices that are driven by an unpopular BSM policy, that deviate so substantially from underlying market fundamentals, and that could be eliminated at any time by state, FERC, or federal policy changes. These same risks might also translate into higher contract prices for State-contracted resources.

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15 To the extent that some capacity resources are presently under Power Authority ownership or contract, the full extent of these capacity price increases may not fully flow through to customers (*i.e.*, the Power Authority would pass through realized costs, which may be hedged). Any bilateral contracts with competitive retail providers may similarly provide a hedge, but the value of this hedge would only be passed through to end use customers to the extent that the customers themselves have engaged in multi-year price commitments to specific retailers.

What Are the Primary Design and Implementation Choices?

Design and implementation considerations are largely the same as under *Structure 1: ICAP Market with Status Quo BSM*. The differences relate only to the BSM structure itself and how to avoid, mitigate, or reduce the inefficient impacts of BSM on customers and society. Opportunities to reduce the impacts of BSM would not be a matter of state control; and instead would be dictated within any applicable FERC rulings. Several of the potential strategies for mitigating BSM impact involve legal views or legal analysis; we are not able to comment on any such legal matters.

The opportunities the State may have to influence the scope and impact of BSM could potentially include:

- Support federal legislative changes to eliminate BSM, or ensure that it would narrowly apply only in cases of market manipulation.
- Use all available legal appeals processes before FERC and in response to FERC Orders to eliminate or reduce the scope/applicability of the BSM.
- Work with NYISO and within FERC proceedings to pursue BSM design variations that would tend to reduce the impact of the BSM such as:
  - Achieving a renewables exemption that is as large as possible and that allows permanent carry-over of unused exemption quantities,
  - Reducing the required number of auctions for BSM resources to clear before they become unmitigated, for mitigated resources reduce the MW of resources subject to mitigation over a pre-determined sunset period, or imposing a maximum number of auctions when BSM can apply to any mitigated resource, and
  - Reducing the applicable MOPR prices through design choices such as the inclusion of REC values as an offset to MOPR prices and technical parameters that would reduce MOPR prices.
- Adopt increased carbon pricing and/or enhanced E&AS market scarcity pricing, both of which would allow for lower mitigated capacity offers. These changes alone would not solve the problems that BSM poses.
- Examine, from a legal perspective, whether a structure such as the FERC-approved "Fixed Resource Requirement" (FRR) structure in PJM could be developed within New York, which could be used to delegate responsibility for meeting resource adequacy requirements to the State or to distribution utilities. We understand that a similar structure in Southwest Power Pool (SPP) uses a Tariff structure to designate States as having authority to oversee resource adequacy, and Midcontinent ISO (MISO) Tariff provisions allow states to override the planning reserve margin requirement estimated by MISO to meet 1-in-10 resource adequacy needs. Each of these approaches offers a range of options for how extensively to share control with FERC and administrative responsibilities with the ISO.
- Take resource adequacy entirely under State administrative control.

- (Least preferred.) Consider a range of options for otherwise mitigating the impacts of BSM through more complex ICAP design changes such as through ISO-NE's CASPR or PJM's ReCO proposal. We consider this avenue to be less preferred than any of the prior approaches given the flawed economics embedded in the premise of such a design. We would only recommend considering such variations to the extent that there is no better alternative path. Dozens of such options were considered in both ISO-NE and PJM's stakeholder forums, all of which suffered from the same fundamental problem of a mismatch between price formation and underlying supply-demand fundamentals.

What Are the Primary Advantages?

The only advantage of an expanded BSM comes from the perspective of incumbent capacity suppliers. These suppliers will continue to earn higher revenues consistent with their original expectations when investing in merchant assets. From their perspective, the higher capacity prices under expanded BSM would be perceived as "fairer." However, our view is that the expanded BSM would ultimately undermine even incumbent suppliers, by deterring the State from continuing any long-term participation in the capacity market.

What are the Primary Disadvantages?

The primary disadvantages of expanded BSM include:

- Large excess costs to customers and society.
- Loss of the capacity market's role to manage retirements and new investment efficiently (given the built-in mismatch of prices with supply-demand fundamentals).

C. Structure 3: Centralized RAC Market without Buyer-Side Mitigation

How Does it Work?

Structure 3: Centralized RAC Market without BSM is substantively very similar to the *Structure 1: ICAP Market with Status Quo* from a market design perspective. Key differences are that it would be administered by the State using the state's authority over resource adequacy rather than by NYISO, and the State would not apply market screens akin to BSM. This would improve economic efficiency, eliminate the excess supply problem, and reduce customer costs to the level needed to maintain resource adequacy through competitive price signals. The prevailing prices may be low for a period as more clean energy and storage resources come online to meet CLCPA mandates, but this would not be considered a problem to address. Instead, low resource adequacy credit prices would simply be considered as a reflection of excess supply conditions, a signal to retire more fossil resources until supply-demand balance is restored.

The structure would also fundamentally differ from an administrative standpoint. The State would take control of the resource adequacy market and would eliminate the BSM (except as applied by PSC on a case-by-case basis to prevent the intentional introduction of uneconomic capacity to profitably suppress capacity market prices). The State could also take over the administrative responsibility of conducting the resource adequacy market, or could share administrative responsibilities with the NYISO whenever that makes sense.

What Are the Primary Design and Implementation Choices?

Many of the implementation questions related to *Structure 3: RAC Market without BSM* may be driven by legal analysis of what institutional, Tariff, and legal structures must be in place in order for the State to take on responsibility for resource adequacy, and what limitations these considerations may impose on the market design. We do not offer any legal opinions in this respect.

From an implementation perspective we also anticipate that there could be a range of options for how to administer the no-BSM centralized RAC market, including:

- RAC market is administered by the State, including all administrative responsibilities that are currently implemented by the NYISO including setting resource adequacy and demand curve parameters, overseeing resource qualification and RAC ratings, developing and approving rules, conducting auctions, and implementing settlements.
- Sharing market administration responsibilities between the State and NYISO in order to reduce implementation costs and leverage the existing capabilities of the NYISO. To minimize the effort required to develop these administrative capabilities, it may be possible for the State to take on only the portions of ICAP market administration deemed necessary to maintain State decisional control. For example, the State may choose to leave some functions with the NYISO, such as establishing quantity requirements needed to meet reliability standards, resource ratings, resource qualification, tracking and accounting for RAC positions and bilateral transactions, monitoring performance, implementing penalties, and settlements. The State could take on the core procurement role of auction administration to establish prices and commitments.
- RAC market continues to be administered by the NYISO (though approval of rules is shifted to the state). This may incur the lowest implementation costs.

What Are the Primary Advantages?

The primary advantages of the *Structure 3: Centralized RAC Market without BSM* include:

- Eliminates the inefficiencies that would be associated with BSM. Prices reflect actual quantity of resource adequacy supplied.
- The State approves the rules, thus avoiding risks of future FERC-policy decisions that could conflict with State policy goals. Elimination of State/FERC disputes would reduce associated regulatory risk and uncertainty.
- Continued use of a time-tested market design and structures that have been proven to reliably meet capacity needs at competitive prices across a wide range of market conditions.
- State administration of resource adequacy procurement may enable more opportunities to align procurement of resource adequacy credits with clean energy needs (discussed further under *Structure 5: Co-Optimized Capacity and Clean Energy Procurements).*

- Consumers do not pay for redundant or artificially inflated capacity costs.

What are the Primary Disadvantages?

The primary disadvantage of the *Structure 3: Centralized RAC Market without BSM* would include implementation costs associated with legal and institutional changes, as well as the need to develop or shift institutional expertise from NYISO to a State agency. These costs might be minimized if some administrative functions remain with the NYISO.

D. Structure 4: LSE Contracting for RACs

How Does it Work?

Structure 4: LSE Contracting for RACs would entirely eliminate the centralized capacity auctions, and would instead rely on LSEs to secure enough resource supply obligations to meet their own customers' needs by assembling portfolios of contracts through bilateral markets.

The mechanics for meeting resource adequacy needs would be as follows:

- The NYSRC would establish capacity requirements similarly to the analysis that is done today, and in coordination with NYISO and others. These would be translated into quantities of RACs needed to meet the 1-in-10 reliability standard on a system-wide and zonal basis.
- Supply resources would be qualified to create RACs (as with UCAP qualifications today). Each RAC would be tied to a specific market locality based on congestion boundaries currently defined by the NYISO, creating four separate products that can trade at different prices on the bilateral market (NYC-RACs, LI-RACs, GHI-RACs, and RoS-RACs). Once created by a resource, they could be sold by the resource adequacy supplier as a fungible bilateral product with equal value regardless of which resource has created the RAC (including whether that resource was clean or fossil). The RAC product could be freely traded in bilateral transactions at a privately agreed price.
- System and locational RAC needs would be imposed on LSEs in proportion to their customers' locational peak loads, with separate requirements for: (a) total MW of RACs that must be surrendered (regardless of the location); and (b) a specific minimum share of the total RACs that must be met from supply within the relevant resource adequacy zone(s). For example, an LSE in New York City might face a resource adequacy requirement for the submission of RACs to cover 107% of customers' peak annual load, of which 85% must come from G-I-RACs or NYC-RACs, and of which 79% must come from Zone J RACs.
- To meet the RAC requirements, each LSE would first use any allocated RACs from NYSERDA clean energy contracts. The remaining quantity of RACs needed to fulfill the requirement would be procured on a bilateral basis from capacity suppliers through any combination of long/short/medium term contracts, non-forward bilateral trades, and self-supply. The LSE and capacity seller would jointly negotiate the price, duration, and other terms of any such contracts.

- Each LSE would be subject to a "compliance showing" prior to the delivery year (or season, month, *etc.*). The LSE would need to surrender the required quantity of system and locational RACs to demonstrate compliance with resource adequacy requirements. Any shortfall would be subject to a penalty, akin to the price cap that currently exists in the ICAP market.

What are the Special Considerations Associated with the Bilateral-Only RAC Market?

Without a transparent centralized auction price to reference, it may be challenging for LSEs to determine whether any particular contract or trade reflects an attractive competitive price. Similarly, for state regulators, the ability to mitigate supplier market power would be more difficult.

A bilateral-only market would not incorporate a transparent, administrative sloping demand curve. While buyers' willingness to pay would likely decrease at higher levels of quantity purchased, it would be difficult to encourage purchases at quantities much greater than the required minimum. This would lose the benefits a sloping demand curve provides to moderate price volatility and express the incremental value of reliability as a function of market conditions even as supply exceeds the required minimum.

In addition, the short-term RAC markets under Structure 4 are likely to face other challenges associated with non-forward bilateral markets. The bilateral markets are likely to face high price volatility and end-price effects (*i.e.*, prices that converge either to zero or to the shortfall penalty rate as the market approaches the compliance deadline and market participants realize that the market is either over- or under-supplied). This outcome is most prominent in compliance structures with fixed compliance targets, and is one reason that NYISO's ICAP market has adopted a sloping demand curve in the spot capacity auctions.[16]

Bilateral markets also offer mixed success in other efficiency dimensions. Bilateral markets tend to be less liquid, less transparent, and impose more transactions costs than centralized auctions. It is also more challenging to monitor and mitigate the potential exercise of market power. These problems tend to be the most challenging in bilateral markets that rely entirely on bilateral contracting. Bilateral markets supported by a well-defined product and trading mechanism (such as the pre-spot-market UCAP transactions that already exist today) can greatly improve liquidity. The involvement of brokers or (even better) third-party exchange trade platforms can further improve liquidity and transparency, but their interest to support such markets depends on there being sufficient trade volume to offset transaction and opportunity costs.

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[16] To mitigate bilateral market price volatility, REC and emissions markets often use banking (and sometimes borrowing) mechanisms to mitigate price volatility and end price effects. Banking is sensible for these environmental products (which have nearly equivalent societal value across delivery years), but does not make sense for the RAC product (which represents reliability within a single delivery year and has no system value that can be meaningfully transferred between years).

What Are the Primary Design and Implementation Choices?

Structure 4: LSE Contracting for RACs is the greatest departure from the current New York resource adequacy structure as compared to all other options. This design would introduce significant changes in the role and business activities of State agencies, utilities, retailers, and capacity providers. Some of the most significant implementation questions facing the State would include:

- **How to develop the mechanics of LSEs' RAC compliance showings and penalties.** A starting point for these compliance showings could be either the California system through which LSEs demonstrate resource adequacy compliance, or possibly REC market showings. The State would need to determine the forward timeframe at which LSEs must demonstrate compliance, the mechanics of submitting and surrendering RACs, and the applicable penalty rate for non-compliance. For the penalty rate, the State would also need to decide the appropriate size of this penalty, whether the LSE would be allowed to recover penalty-related costs from customers, and whether penalties can be forgiven in certain "good faith" circumstances.[17]

- **How to support a healthy bilateral market.** There are several opportunities to at least partly mitigate the liquidity, transaction cost, and transparency challenges associated with the bilateral RAC market. One is the introduction and continuation of a liquid, tradable RAC product market, including a tracking mechanism to keep accounts. This could start with the UCAP tracking system currently used to support the short-term bilateral ICAP market, but possibly also allowing individual market participants to create more RACs on a 2-3 year *forward* basis in order to facilitate additional bilateral trades. For example, MISO's market participants are actively trading within the short-term bilateral UCAP credit market, but regularly request trading support for forward UCAP credits. Market participants will also greatly value transparency in bilateral market prices as well as supply-demand balance information. To produce additional price transparency, the regulator could require disclosure of RAC terms and pricing. It could also be helpful for the regulator to support periodic voluntary auctions. Exchange-trade markets and brokers can also provide some limited pricing transparency, but only if there is a robust enough volume of trade that these market-makers would be interested to support the market. Regular State reports on near and long-term supply-demand fundamentals can help capacity sellers and utilities assess whether the after-market is over- or under-supplied. These various options can help support a healthier bilateral market, but challenges with bifurcated pricing for new and existing resources, as well as price volatility driven by even small amounts of over- or under-supply, will likely remain—absent a demand curve for capacity.

What Are the Primary Advantages?

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[17] See Section II.A.2 of this paper for a description of these mechanics and the applicable penalties in the context of California's resource adequacy construct. Pfeifenberger, Johannes, Kathleen Spees, and Samuel Newell, "Resource Adequacy in California: Options for Improving Efficiency and Effectiveness," October 2012.

The primary advantages of the *Structure 4: Utility Contracting for RACs* include:

- Shift of capacity regulation by FERC to resource adequacy regulation by the State enables the elimination of BSM costs.
- Price certainty for the subset of capacity resources (likely new resources) that could be achieved through multi-year forward contracts for RACs that do not exist today.
- Any synergies or multi-product efficiencies that individually-crafted long term contracts may allow.
- Consumers do not pay for redundant or artificially inflated capacity costs.

What are the Primary Disadvantages?

The primary disadvantages of *Structure 4: LSE Contracting for RACs* include:

- Reduced ability to monitor and mitigate supplier and buyer market power abuses as compared to a centralized auction.
- Short-term bilateral market and monopsony price discrimination, if undetected by regulators, could produce uneconomically low prices for existing resources, potentially contributing to early retirements.
- Short-term bilateral markets may face low liquidity, low transparency, and high price volatility, as compared to the current ICAP market.
- Greater transactions costs to the system.
- Significant policy effort and transition costs incurred to achieve a fundamental change in roles for State agencies and utilities.

E. Structure 5: Co-Optimized Resource Adequacy and Clean Energy Procurements

How Does it Work?

Structure 5: Co-Optimized Capacity and Clean Energy Procurements would begin with *Structure 3: Centralized RAC Market without BSM*. The primary difference in *Structure 5* would be that all system clean energy requirements would be achieved through a centralized, co-optimized RAC and REC procurement market.[18] Under this design option, the state would largely replace its current long-term procurements for clean energy resources with a RAC+clean auction as the

[18] In a separate publication we have laid out a generalized and detailed approach to the development of a Forward Clean Energy Market (FCEM) that somewhat matches this design option; in this memo we offer a higher-level description of an approach that is adapted to New York's unique circumstances. Spees, Kathleen, *et al.* "How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals," September 2019.

primary vehicle for meeting most resource adequacy and clean energy needs. To provide more revenue certainty to suppliers, the auction could offer new resources a term of 7-20 years for RECs (the specifics of term and products under that multi-year term would be a major design question).

The mechanics for meeting resource adequacy and clean energy needs would be as follows:

- The State would establish RAC needs consistent with the 1-in-10 Standard as described under Structures 1-3 above, with the compliance obligation to meet system and local RAC requirements imposed on retail providers.
- In addition, the State would establish clean energy requirements consistent with the CLCPA that would also be imposed on retail providers. For example, these requirements in 2030 could be expressed as:
  - **A 70% total REC obligation** where RECs can be sourced from any combination of OSW, Tier 1 renewables, Tier 2 renewables, existing hydro, distributed solar, *etc.*, and of which a specified subset or carve-out must come from: (a) distributed solar RECs (DS-RECs), and (b) offshore wind RECs (OSW-RECs). Together, these requirements would ensure compliance with the OSW, distributed solar, and total 70% renewables state mandates.
  - **A total clean energy obligation** that would exceed the 70% renewables obligation by the year 2030 and rise to 100% of all energy needs by the year 2040. RECs would be eligible to contribute to this obligation as would nuclear ZECs.
  - **A storage obligation** load-share-based requirement for storage credits in RAC MW units, the product could be referred to as Storage-Credits.
- The State would significantly reduce (though likely not eliminate) the current contract solicitation and procurement approaches used to meet these State-mandated resource procurement targets. For example, the state may decide to cease future contract procurements for Tier 1 renewables (relying instead on a centralized auction), but continue current practice to engage in separate OSW procurements.
- For any State-contracted resources, the REC and RAC value of the associated resources would be earned through the co-optimized clean+capacity market, but then subtracted from the awarded contract price.[19]
- New renewable resources would likely be offered a multi-year commitment in the quantity of RECs sold, for example with a 7-20 year delivery period. The specifics of the term and whether a multi-year commitment would also be offered on new resources' RAC value would be one of the primary design choices to consider (see below).
- Retailers would have the option (but no obligation) to engage in forward contracting to meet their customers' REC, storage, and RAC obligations through short- or long-term

19 An alternative and essentially equivalent approach would be to subtract the quantity of RACs and RECs procured in each state contract from the quantity procured in the auction.

contracts or through bilateral exchange markets. Any remaining requirements would be procured through a co-optimized RAC+clean energy auction.

The State-run co-optimized RAC+clean energy auction would be designed to procure the least-cost combination of all resource adequacy and clean energy needs. LSEs would participate by submitting all of their self-supply RECs, Storage-Credits, and RACs into the auction, which would be deducted from the quantities procured on their behalf. LSEs holding excess supply of any one product would earn net revenues from selling that excess at the auction clearing price. Resource owners would participate by submitting any unsold REC, Storage-Credits, and RAC volumes into the auction at a price of their choosing, subject to monitoring and mitigation rules. For RAC-only resources such as demand response, the offer format would be in $/kW-month units and tied to a specific resource adequacy zone, similar to the current ICAP market. For a clean-energy-only resource (such as a wind plant that has no capacity injection rights), the offer format would be in $/REC units. For resources that provide meaningful quantities of both RAC and clean energy value such as hydropower, the offer could be submitted as a total revenue requirement in units of $/year units but tied to a specific quantity of RECs and locational RACs. A RAC+clean resource would clear the market only if the prices across multiple products were high enough for it to recover its total $/year revenue requirement. Similarly, storage would earn revenue through both Storage-Credit value and RAC sales, with the total offer price denominated on a $/year basis. Resources would be assumed to be indifferent as to what fraction of revenues would be earned through the sale of RECs versus RACs.

A downward-sloping administrative demand curve would be used to represent total system-wide demand for each product to be procured. There would be as many different demand curves as there are individual LSE requirements, including: (a) a system-wide resource adequacy demand curve, with sub-requirement demand curves expressing the fraction of total resource adequacy need that must be met within each resource adequacy zone; (b) a demand curve for the total New York renewable energy, with sub-requirement demand curves for the fraction of total demand to be met through OSW and distributed solar; (c) a demand curve for the storage resource requirement; and (d) if relevant, a total clean energy resource requirement that exceeds the renewables requirement and that could be met through either ZECs or RECs. The downward-sloping shape of the curves would help to introduce price stability for each product and could be used to express the incremental reliability value for RACs and policy value of RECs as a function of quantity.

The auction would be cleared using an optimized clearing engine.[20] The auction would procure the least-cost combination of offers to meet each of the demand curves, with prices set based on

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20 Specifically, the optimization function would maximize social surplus, or area under the demand curves minus procured resource cost. This optimization formulation would be more complicated than the current heuristic-based clearing used in the current NYISO ICAP auction, but still (in our view) not materially more complicated than other auction formulations such as the two-season optimized capacity auction developed in Ontario and the multi-product optimization that PJM has previously used for annual and sub-annual resources. We note that ISO-NE staff take a different view from us, and have

the demand curve price consistent with the clearing quantity for each product.[21] Price formation would respect the multi-value nature of certain products. For example, OSW-RECs could clear at or above the REC price (but OSW-RECs would never be priced below RECs); Zone J RACs could clear at or above the system-wide RAC price (but never below). Each resource would earn a value-stack of revenues, calculated as the sum of cleared quantity times cleared price across all products sold. The optimized clearing approach would ensure each seller's satisfaction with the final clearing results: sellers earning equal or more than their offer price would clear the auction, while sellers that would earn less than their offer price would not clear. The "lumpiness" of resource entry and exit would be accounted for in offer structures, with the seller stipulating whether the resource can be accepted in part (a rationable offer) or whether it must be accepted in full (a lumpy offer).

Though there is extensive experience with similarly-formatted capacity auctions, there is relatively little real-world experience with such a co-optimized RAC+clean energy auction. However, the design of Mexico's recent (but now abandoned) long-term contract procurements model is one somewhat similar example.[22] Those procurements stipulated a quantity of energy, capacity, and clean energy credits (CECs) to procure under contract durations of 15, 15, and 20 years, respectively. Both clean and fossil resources were able to compete in an all-source procurement with each resource rated with respect to the bundle of energy, capacity and CECs up for sale. Offers could be made in total dollar terms for the bundle of goods (rather than specifying separate offer prices for each product). The procurement selected the least cost combination of offers to meet minimum procurement needs.

This sort of auction structure could be considered a natural extension of the current capacity auction structure, and developed on an evolutionary basis in New York. Rather than transitioning overnight to such a significantly different design, the general concept could be tested on a provisional basis by adding a small quantity of REC procurements into the RAC auction on a co-optimized basis and growing that procured quantity of RECs, Storage-Credits, and so on over time as the auction proves its effectiveness and as CLCPA requirements grow.

What Are the Primary Design and Implementation Choices?

Structure 5: Co-Optimized RAC and Clean Energy Market could be implemented with a wide range of design variations to address specific policy priorities, including:

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previously advised that a co-optimized clean energy plus capacity auction is complicated enough that it could take multiple years to design and implement in their market.

21 Note: In a multi-product auction such as this, it is not possible to simply stack up supply versus demand and set clearing prices and quantities at the intersection. For example, a resource earning substantial capacity revenues will be treated as if its "effective offer price" for RECs is relatively low and can clear at a low REC price. The same resource would be incorporated at a relatively high REC price if it earns very little from its capacity product.

22 See additional information in: http://www.awex-export.be/files/library/Infos-sectorielles/Ameriques/2017/MEXIQUE/Mirec-Report-2018-The-BIG-Mexico-renewable-energy-report-ENG.pdf

- **Forward period and term.** The current NYISO ICAP spot auction is non-forward and has a delivery period of only one month. These parameters can be adjusted however, if New York wished to achieve some financing cost advantages (at the expense of shifting some investment risks from suppliers to customers, and somewhat limiting the ability of new and existing resources to compete). Options include:
  - *Increasing up to a three-year forward period.* A three-year forward period aligns resource commitments with most generation resource development timelines, offering an advantage to resource developers that can be certain that the resource is in the money and needed prior to making irreversible financial commitments. Forward auctions also invite more competition from potential new resources and produce greater price stability. A disadvantage is greater customer exposure to forecast error.[23]
  - *Increasing to annual or seasonal six-month delivery periods.* A longer commitment period of up to 6 or 12 months could incrementally improve revenue certainty for producers, without sacrificing the level of granularity consistent with how resource adequacy is measured.
  - *REC price lock-in for new resources.* If the state wanted to offer additional financing certainty for new resources, a multi-year price lock-in could be made available. There is some precedent for offering such a price lock-ins in other capacity markets, with PJM offering a three-year lock-in to a small number of resources and New England offering a seven-year lock-in to all new resources. From a capacity/REC market perspective, we are skeptical that any lock in is necessary given that both PJM and New York have attracted new resources without a lock-in; the centralized auctions, demand curves, and certainty of a long-term market need for capacity seem to provide sufficient signals to attract cost-effective resources. We see a stronger rationale to offer a price lock-in on REC products for new resources, given that the need for RECs is subject to greater regulatory and policy risk. Under this approach, sellers would be eligible to earn their year-1 REC price and quantity commitments for the duration of the price lock in (perhaps 7-20 years), after which they would be eligible to continue to sell RECs on a year-to-year basis at the going price. The seller would then gain significant certainty in support of the REC portion of their asset's value (subject to the greatest regulatory risk), while taking full merchant risk on the energy and capacity values (subject to more fundamentals-based risk but relatively little regulatory risk).

    As disadvantages, a price lock-in approach somewhat limits the competitive playing field, favoring new and longer-lived resources over existing and shorter-lived resources. To mitigate this potential disadvantage, one approach would be to introduce the lock-in with a certain term (say 20 years) but reduce the term gradually in each

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23 A more comprehensive discussion of the advantages of a forward vs. non-forward auction (at least in the context of capacity needs) is available in our prior report for the NYISO on the benefits and cost of a forward capacity market. Newell, Sam, *et al.* "Cost-Benefit Analysis of Replacing the NYISO's Existing ICAP Market with a Forward Capacity Market," June 2009.

successive auction with a plan to reduce to a shorter period (eventually down to 7 years or even 1 year) over a pre-defined sunset schedule, with that schedule to be revisited periodically based on lessons learned.

- Technology-specific requirements. RACs would be treated on an entirely resource-neutral basis, with no preference among resource types. However, several State policy requirements under CLCPA do require the achievement of technology-specific requirements of OSW, storage, and distributed solar. Further, the design can be developed to enable ZEC participation to meet longer-term 2040 clean energy goals (but not 2030 renewable-only goals). Potential approaches to representing technology-specific requirements include:
  - *Existing+new technology-specific resource requirements (for OSW, storage, and distributed solar).* These requirements would be incorporated into the auction as technology-specific demand curves, but would not discriminate between new and existing resources of that type. OSW and distributed solar requirements would likely be translated into REC terms, while storage might be delineated in installed MW terms. Prices available for OSW-RECs and DS-RECs would be equal or greater than prices available for other RECs, and new resources would be eligible to lock-in that higher price for the specified new resource lock-in term. Further, the price cap relevant for the technology-specific demand curves may be higher than the price cap relevant for generic RECs, to the extent that these resources are known to be more expensive on a $/MWh basis (net of anticipated capacity and energy revenues). We anticipate that this approach would be sufficient to support entry for storage and distributed solar resources to meet State requirements, but may be less desirable than the following approach in the context of OSW.
  - *New resource carve-outs (especially for OSW, but also an option for storage and distributed solar).* If the state wished to ensure greater certainty on the schedule of large, lumpy OSW developments, the auction could incorporate an explicit requirement for a quantity of OSW-RECs from *new resources* to be procured in each auction.[24] This would be implemented through an explicit demand curve for *new* OSW-RECs, but potentially with a longer price lock-in (*e.g.*, up to 20 years) or higher price cap. The shape of the demand curve would reflect tolerance for shifting the procurements to a later date if offer prices should come in higher than expected (and any un-procured new OSW-REC quantities would revert to procuring generic REC suppliers).

    Once the lock-in term is concluded, there are two possible ways to handle these resources: (1) to roll them into a secondary requirement for new+existing OSW-RECs, allowing them to earn the same price as other existing OSW resources on a year-by-year basis (while earning a perpetual price premium relative to generic RECs); or (2) to

[24] See Appendix Section H.3 of Spees, Kathleen, *et al.* "How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals."

roll them into the generic REC pool. The preferred approach may depend on how the CLCPA is interpreted. If the minimum resource requirements are interpreted to require that minimum requirement of resources for the compliance year *and all subsequent years*, then the first option may be more sensible. If the technology-specific requirements can allow for backsliding in later years as long as overall 2030 and 2040 renewable/clean goals are met, then the second option could produce lower long-run costs.

  – *Lower-tier eligibility for nuclear resources*. Finally, the State will eventually need to determine the eligibility status of nuclear resources given that they are eligible for ZECs through 2029, do not contribute to the 2030 70% renewables requirement, but can contribute to the 2040 100% clean energy requirement. The overall most economic solution might be to maintain some or all of the nuclear resources in contribution toward the 2040 goals (but only if they are cheaper than retiring those resources post-2029 and building more renewables prior to 2040). The relative economic value of nuclear compared to renewables could be expressed through: (1) a system-wide renewables demand curve reflecting 70% of delivered energy (for all years 2030+), including a downward slope that accounts for some tolerance above/below 70%; and (2) a total REC+ZEC clean energy demand curve for which both renewables and nuclear are eligible, perhaps reflecting a quantity at 75% of delivered energy in 2030 and then growing to 100% of delivered energy by 2040, again including a downward sloping curve that accounts for tolerance above/below the target quantity. REC prices would always clear at or above the price for which nuclear resources are eligible, meaning that nuclear plants will retire if and when renewables be come cheap enough to undercut the cost of continued nuclear life-extensions. The REC demand curve would be higher and steeper than the REC+ZEC demand curve, given the difference in policy objectives. The REC demand curve expresses a mandatory policy requirement. The REC+ZEC demand curve (in the early 2030s) would reflect a willingness to pay to accelerate achievement of decarbonization in excess of the 70% requirement; by 2040 however the REC+ZEC demand curve would reflect a total mandatory policy requirement.

- Separate or co-optimized auction format. In concept, this design could be implemented as two separate auctions: one for clean energy needs followed by a separate auction for RAC needs. Even as a two-stage auction, this design would enable a certain amount of co-optimization to the extent that sellers could project RAC value and subtract that value from the offer price in the clean energy auction. The primary advantage of such a two-stage auction would be the relatively simpler implementation and ability to separate the auctions in time and administrative responsibility. The disadvantage would be to forfeit the full co-optimization benefits. In other regions, we expect that separate auctions for the clean and RAC values may be the most feasible approach for practical and institutional reasons; in New York we are more optimistic that these two types of procurements could be combined into one auction given the single state approach.

- **Demand Curves.** The shape of the demand curves for each REC and RAC product would be designed considering principles of value, price formation, tolerance for quantity variability, revenue sufficiency, and multi-product interactions, including:
  - *RAC demand curves* with prices tied to the net cost of new entry (Net CONE) for the marginal RAC resource in each location, and quantities based on the 1-in-10 reliability requirement for the system and each zone. These curves would remain largely unchanged as compared to the historical demand curves, except that the marginal resource may evolve to a non-fossil resource type such as storage or another clean technology (especially as the energy value of fossil plants will decline at the same time that policy value for clean resources is increasing). Quantities in the RAC demand curve are a bit right-shifted compared to the 1-in-10 requirement at Net CONE, reflecting greater tolerance for over-procurement as compared to reliability shortfall.
  - *Clean energy demand curves* would be defined somewhat differently.[25] Prices would be set as a multiple above/below a Clean Net CONE (or the estimated REC payment required to attract a new clean energy resource). This would be calculated as the levelized resource cost, minus RAC and energy value in $/REC terms. Quantities on the demand curve would be tied to the minimum policy mandates, such as quantities above and below the 70% by 2030 renewables requirement. For clean energy, the quantity points would be developed considering overall policy objectives and tolerance for shortfalls. For most requirements (such as OSW and 70% renewables requirement) the State may have relatively symmetrical tolerance to absorb shortfall and surplus, with the width designed so as to produce moderate price volatility and mitigate the ability to exercise market power.

    For the total clean energy (REC+ZEC) requirement especially in the years between 2030 and 2040, the policy objectives suggest a low and asymmetrical demand curve. A relatively low price cap could be tolerated (since the REC-only demand curve would incorporate higher prices to ensure that the 70% renewables requirement is met). However, all REC+ZEC quantities from 70-100% could be expressed to have at least some incremental policy value associated with achieving the 2040 clean energy goals sooner (as long as the price is low). This REC+ZEC demand curve would start very flat in 2030, but steepen to reflect higher prices and less quantity tolerance as the state approaches the 2040 100% total clean energy mandate.

What Are the Primary Advantages?

The primary advantages of *Structure 5: Co-Optimized RAC and Clean Energy Procurements* include:

- An enhanced role for retail choice and competitive retailers as compared to all other structures (as retailers can engage in self-supply for all capacity and clean energy needs).

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[25] Spees, Kathleen, *et al.* "How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals," September 2019, Appendix Section B.2.

- An enhanced role for merchant resource developers to take on more risks (shifting risks away from customers) as compared to all other structures.
- Enhanced competition across resource types, vintages, and across products that may achieve lower total costs by enabling more direct competition within one auction.
- Efficiency benefits achieved of co-optimized resource clearing to meet all RAC, clean energy, and other policy requirements simultaneously. This co-optimization would enable reduced reliance on the auction administrator estimates of uncertain parameters (such as the expected RAC value of clean energy resources) in order to select the most cost-effective resources; these separate values would be endogenously determined within a single auction and so remove the need for administrative estimates.
- Opportunities to more fully express policy objectives through downward-sloping demand curves including the value of accelerated decarbonization and enabling some competition between nuclear and renewable resources.
- Build on the successful and proven elements of the historical ICAP market, which would be mostly maintained as-is.

What are the Primary Disadvantages?

The primary disadvantages of *Structure 5: Co-Optimized RAC and Clean Energy Procurement*s include:

- New design concept that is untested and complicated to implement. With the new design introducing implementation costs and the risk of design flaws.
- If new resources are eligible for only short-term commitments, then this approach would forfeit some of the financing cost advantages associated with long-term contracts (though most of the benefits can be maintained if the commitment term for new resources remains at 20 years).
- Forfeit some of the short-term customer benefits that might be achieved under *Structure 4: LSE Contracting for RACs* through price discrimination (*i.e.*, lower payments to existing resources).

III. Summary of Structures' Advantages and Disadvantages

We briefly summarize the relative advantages and disadvantages across all resource adequacy structures in Table 2, as discussed more fully in the body of this memo.

Table 2
Advantages and Disadvantages of Each Structure

Structure	Advantages	Disadvantages
1. ICAP Market with Status Quo BSM	• Least policy & implementation effort • Continued reliance on time-tested ICAP market • Incumbent capacity earns more revenue (though future excess revenues may be discounted by generators due to political instability of BSM regime)	• Excess costs to customers and society • Inefficient life-extension of unneeded fossil capacity • Risk of continued expansion of BSM
2. ICAP Market with Expanded BSM	• Same as #1 (but advantages are reduced as the expanded scope of BSM undermines the alignment of pricing with supply-demand balance)	• Greatest costs to customers and society • Largest effect to inefficiently life-extend and even add fossil plants
3. Centralized RAC Market without BSM	• Eliminates inefficiencies of BSM • Continued use of time-tested ICAP market approaches for resource adequacy needs • Avoid excess costs from BSM	• Implementation costs associated with legal and institutional changes (costs may be modest if some administrative functions stay with NYISO)
4. LSE Contracting for RACs	• Eliminates inefficiencies of BSM • Contracted resources achieve lower risks and financing costs through multi-year commitments • Avoid excess costs from BSM	• Reduced ability for monitoring and mitigation in the bilateral market (potentially the biggest disadvantage) • Risks shifted from sellers to customers • Bilateral market may be less transparent, less liquid, and more volatile • Difficulty implementing a sloped demand curve
5. Co-optimized Capacity and Clean Energy Procurement	• Eliminates inefficiencies of BSM • Continued use of time-tested ICAP market approaches for RA needs • Efficiency benefits of co-optimization, and enhanced competition across products, resource types, and vintages • Enhanced role for retail choice • Shifts risks from customers to sellers • Benefits of demand curve achieved for RECs (not just RACs) • Avoid excess costs from BSM	• Untested and complicated • Greater supplier risks as compared to index REC contracts could come with higher financing costs

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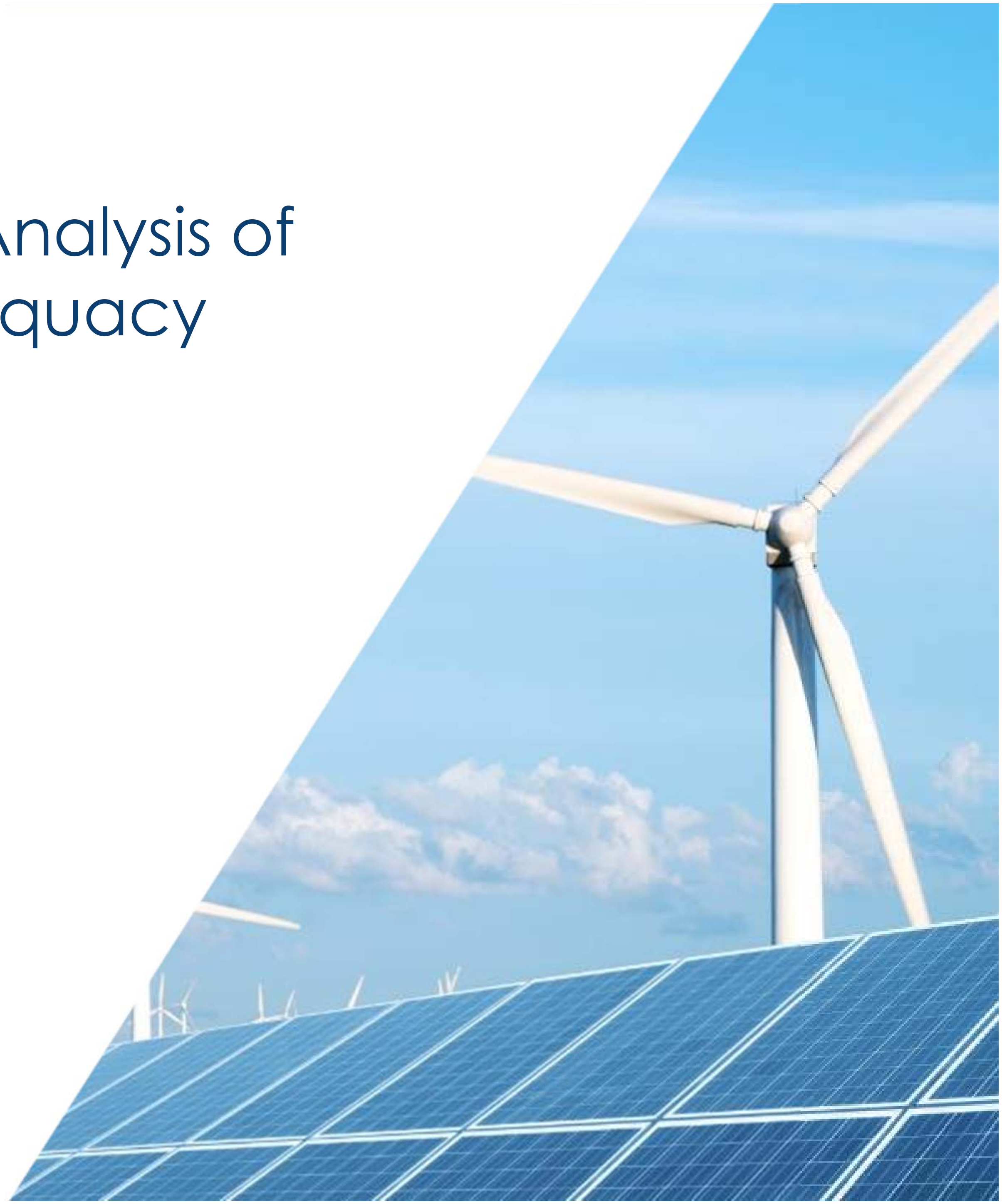
Attachment C

Kathleen Spees, Samuel Newell, John Imon Pedtke, & Mark Tracy, *Quantitative Analysis of Resource Adequacy Structures*, The Brattle Group

(May 19, 2020)

Quantitative Analysis of Resource Adequacy Structures



PREPARED FOR
NYSERDA and NYSDPS

PREPARED BY
Kathleen Spees
Sam Newell
John Imon Pedtke
Mark Tracy

July 1, 2020

THE Brattle GROUP

Study Scope

NYSERDA and NYDPS retained Brattle to evaluate several alternative resource adequacy constructs that differ primarily in who administers them and how Buyer-Side Mitigation (BSM) is applied; this deck presents estimates of the differences in customer costs.

Summary of RA Structures Corresponding to Brattle Qualitative Analysis Memo

Structure		Description	Cost Evaluation
1	**ICAP Market with Status Quo BSM**	Current ICAP market with current rules	Compared to #3 to indicate costs of Status Quo BSM
2	**ICAP Market with Expanded BSM**	Same as above but with potential expansion to BSM rules corresponding to FERC's December 2019 order for PJM	Compared to #3 to indicate costs of potential Expanded BSM
3	**Centralized Market for Resource Adequacy Credits (RACs), without BSM**	Functionally similar to current ICAP market, but with rule-setting by State No BSM, except as applied by PSC to prevent the intentional introduction of uneconomic capacity to profitably suppress capacity prices	Evaluated as "No BSM"
4	**LSE Contracting for RACs**	Same as #3, but with no centralized market LSEs must procure sufficient RACs bilaterally	Similar to #3 but difficult to quantify
5	**Co-optimized Capacity and Clean Energy Procurement**	Same as #3, but a State entity would procure RACs and RECs for LSEs in a joint, co-optimized auction	Not evaluated (out of scope)

Approach and Key Assumptions

To estimate customer cost impacts, we simulated future wholesale markets (including the application of BSM) in 2030, using Brattle's GridSIM model. Key Assumptions:

- Modeled fleet reflects the **Climate Leadership and Community Protection Act** (CLCPA) and **NYISO CARIS study**:
  - 70% of load is met by renewable resources by 2030 (does not include Nuclear generation)
  - Annual gross load, 6,100 MW of offshore wind (OSW), 3,000 MW of storage, and 7,500 MW of behind-the-meter (BTM) solar assumptions consistent with CLCPA targets and 2019 CARIS study assumptions
- Assumptions on BSM applicability were updated to align with NYISO's proposed exemption rule:
  - 1. "Status Quo" applies BSM to new renewables and storage in Zones G-J, except approximately 550 UCAP MW of policy exemptions
  - 2. "Expanded BSM" extends BSM to all zones, incl. nuclear and half of the existing hydro resources (assuming CapEx projects), with exemptions for 160 UCAP MW of OSW in Zone J, 173 UCAP MW of OSW in Zone K, and 41 UCAP MW of PV in Zones G-I
  - 3. Centralized RAC Market w/ "No BSM" does not exclude any resources from the capacity market
- Assumptions on UCAP ratings of intermittent resources affect the magnitude of BSM
  - UCAP value declines with penetration; analyzed output vs. net load to estimate effective load-carrying capability (ELCC)
  - Available output data had low CF% and output diversity, making impact estimates conservative; on the other hand, analysis does not recognize that transmission constraints could make the local J/K value fall faster with penetration
- Other key assumptions: resources' fixed and variable costs contributing to capacity prices via supply elasticity
- Sensitivity analyses: explored effects of nuclear retirements; higher load; quantity of BSM policy exemptions

The 2030 system examined here leveraged CARIS 70*30 and otherwise made necessary simplifying assumptions. While the system examined in 2030 does not represent a prediction of the future system, it is a reasonable expectation for the purpose of examining alternative RA structures

Cost estimates are thus indicative; impact will ultimately depend on the year, load, supply mix, UCAP ratings, and capacity supply elasticity, and the details of any changes to BSM rules

Updates to this Quantitative Analysis

We have updated this quantitative analysis based on stakeholder input received and to better reflect NYISO's proposed BSM rules and recent developments

- The most important changes provide a more accurate representation of likely outcomes under the "Status Quo" buyer-side mitigation approach, including:
  - Higher renewables exemption (assuming that NYISO's April 20 filing is accepted)
  - Sensitivity analysis on the quantity of public policy resource exemptions
  - Offer floor at the minimum of 0.75x mitigation Net CONE or resource offer floor
  - Updated representation of resource retirements and winter only status as per the NY DEC "Peaker Rule" Part 227-3 and 2020 Gold Book
  - Updated going-forward cost assumptions for fossil resources that are at risk of retirement (identified as a key study sensitivity)
- **Overall Impact of Updates:** Estimated customer costs imposed by Status Quo BSM are somewhat lower, but the uncertainty range remains similar at approximately \$0.4-\$0.9 billion per year; Expanded BSM scenario costs remain similar at approximately \$1.3-\$2.8 billion per year

Summary of Conclusions

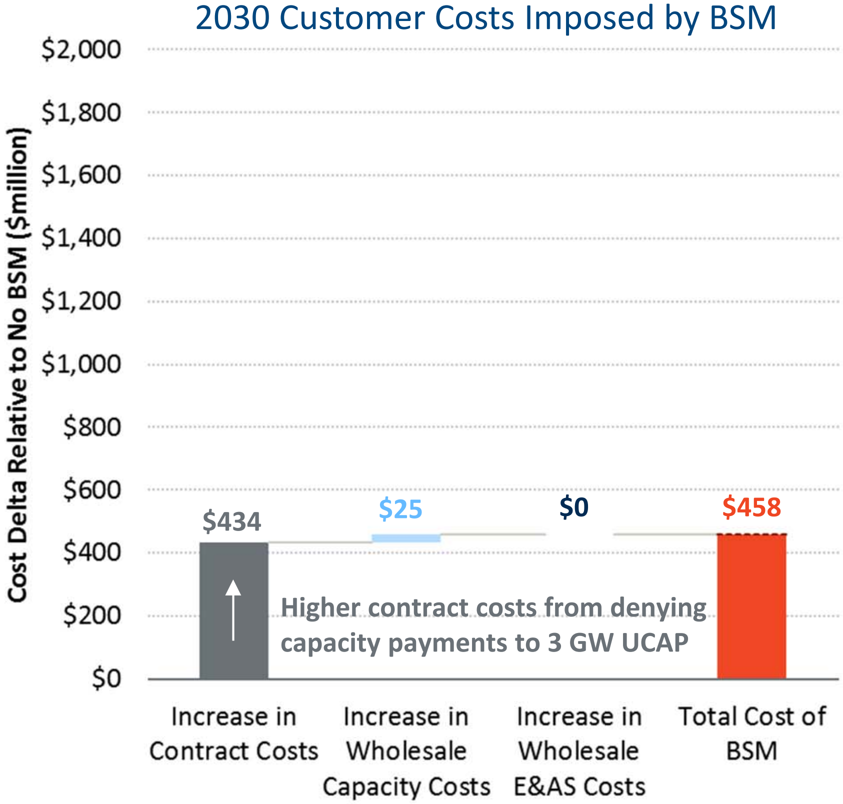
- By 2030 relative to a No-BSM scenario, estimated customer costs increase by:
  - **$0.4-0.9 billion/year** under Status Quo BSM (~12%-20% of statewide capacity costs or ~24%-34% of Zones G-J capacity costs), range depending on load growth and exemptions
  - **$1.3-2.8 billion/year** under Expanded BSM (~35%-63% of statewide capacity costs), range depending on load growth and nuclear resource retention
- This reflects costs of over-procuring capacity because mitigated policy resources would not be accounted for in the capacity market, including:
  - Contract costs increase for policy resources, since they are denied capacity payments
  - Capacity market clearing prices rise
- These estimates account for moderating long-term factors:
  - Long-term supply elasticity mitigates capacity price impacts so it is smaller than the "double-payment" quantity effect (showing up as higher contract costs)
  - Lower resource UCAP values at higher penetration of mitigated renewable resources limit the impact of BSM
  - Offsetting E&AS impacts, but these are relatively small
  - Policy resource exemptions can somewhat mitigate costs

Analytical Results

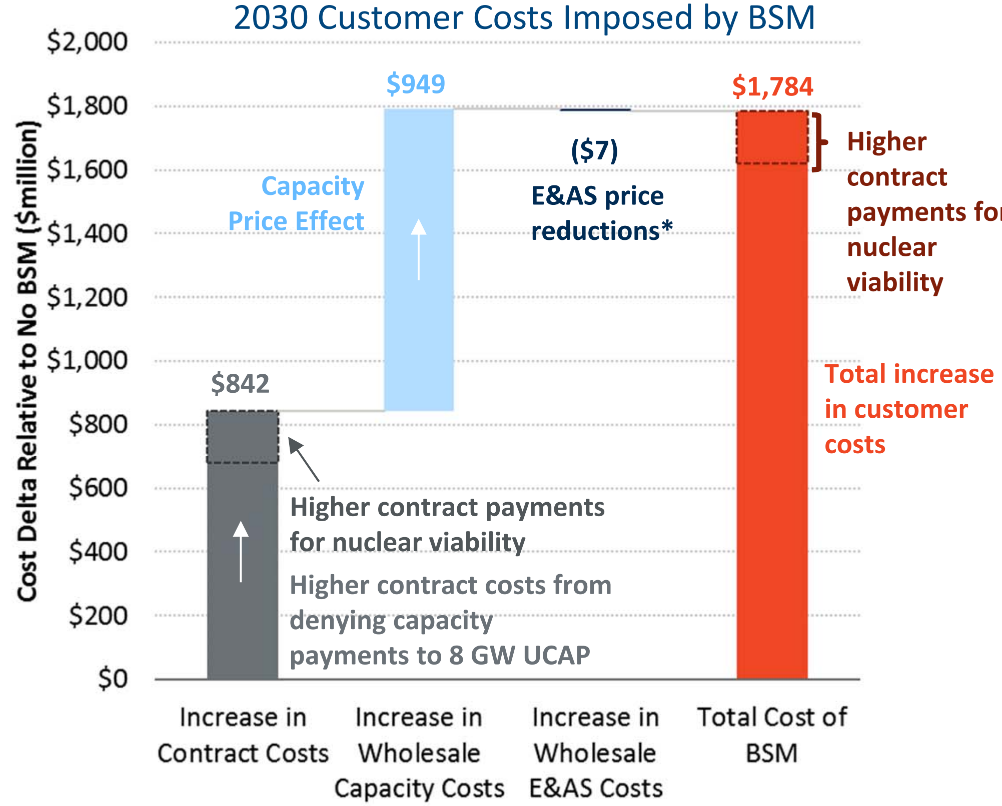
Estimated Customer Costs of BSM in 2030

Net impact of BSM on customers is $0.5 billion/yr under Status Quo; $1.8 billion/yr under Expanded BSM.

Status Quo BSM (#1 vs. #3)



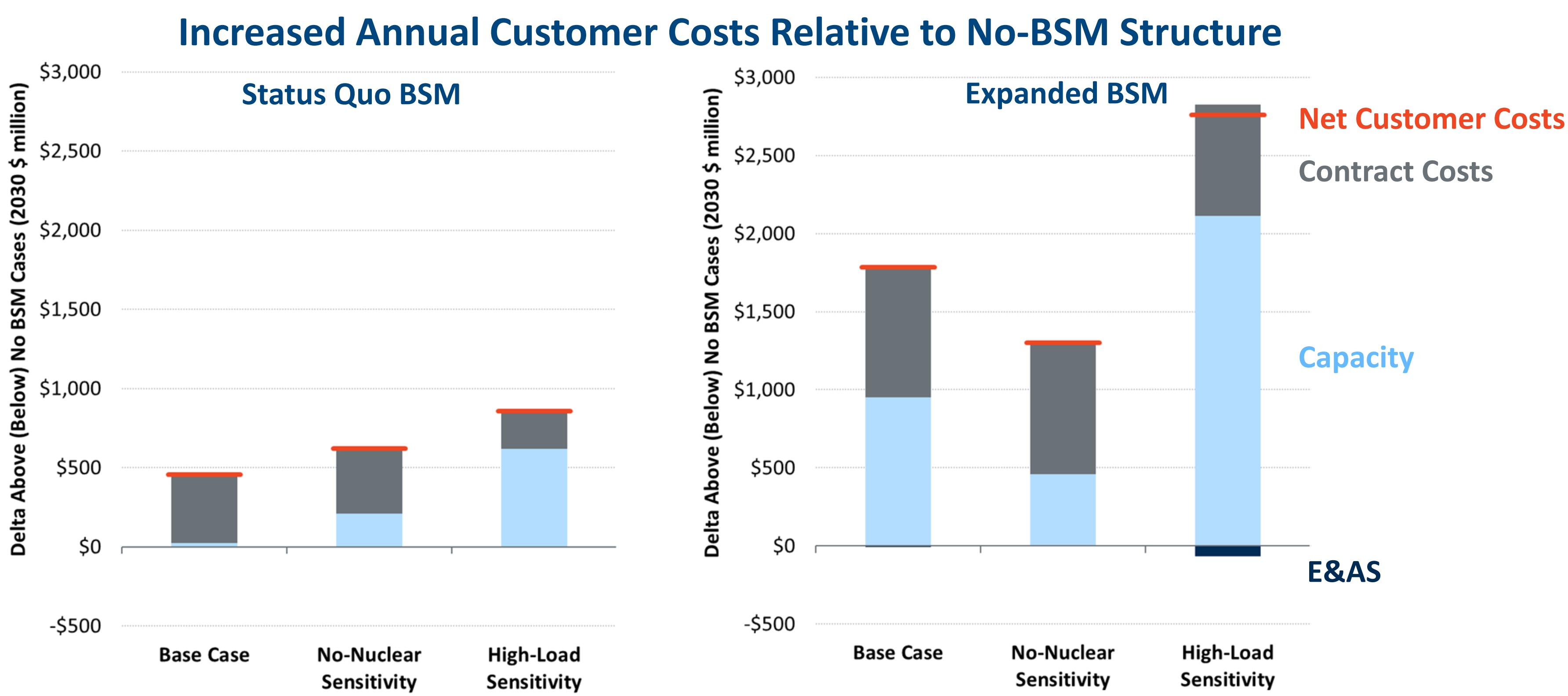
Expanded BSM (#2 vs. #3)



* Energy and AS prices decrease in some cases because excess capacity depresses prices in tight hours; and because higher contract payments (due to lack of capacity payments) cause energy prices to be more negative in over-generation hours.

Sensitivity of BSM Costs to Supply-Demand Balance

Customer costs of BSM are sensitive to peak load (higher load driving higher costs)



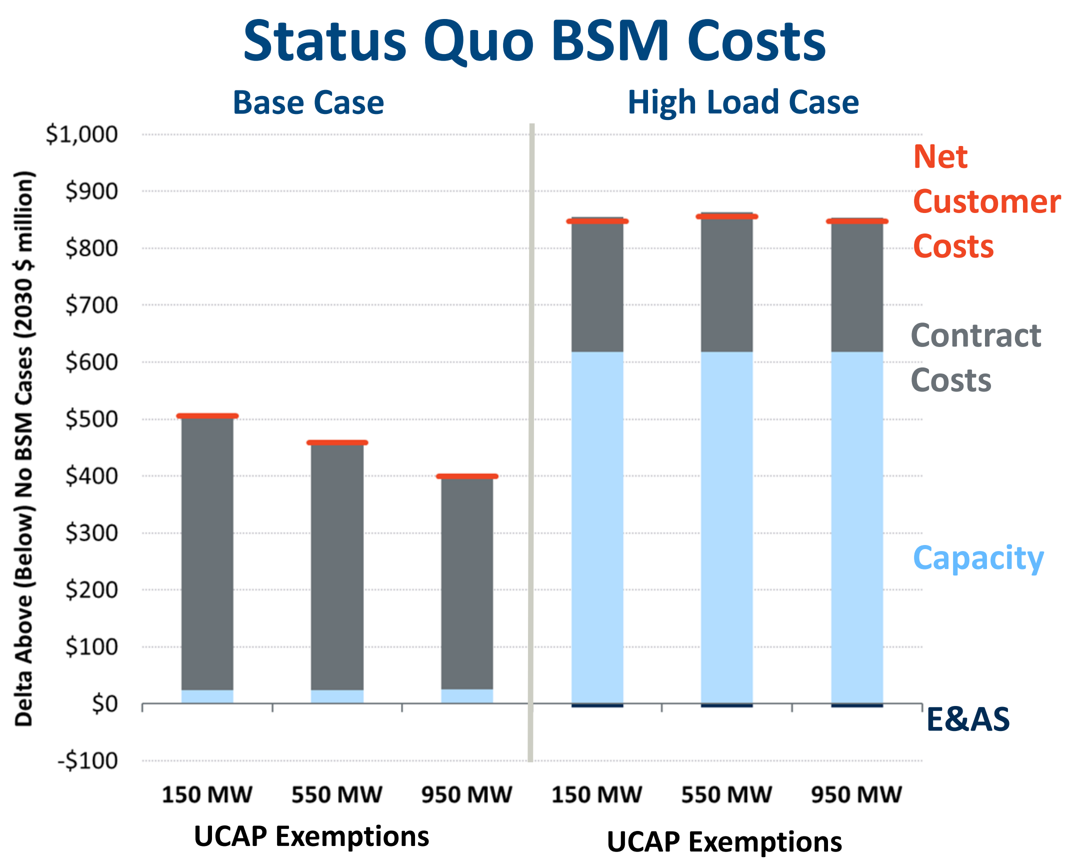
Notes: "**No-Nuclear Sensitivity**" loses all >3 GW of upstate nuclear, largely replaced by retaining gas CCs, so fewer resources to mitigate.
"**High-Load Sensitivity**" results in additions of onshore wind to meet 70% target.

Sensitivity of Status Quo BSM Costs to Policy Resource Exemptions

We evaluated the sensitivity of Status Quo costs to +/- 400 MW of policy resource exemptions

Costs remain similar because:

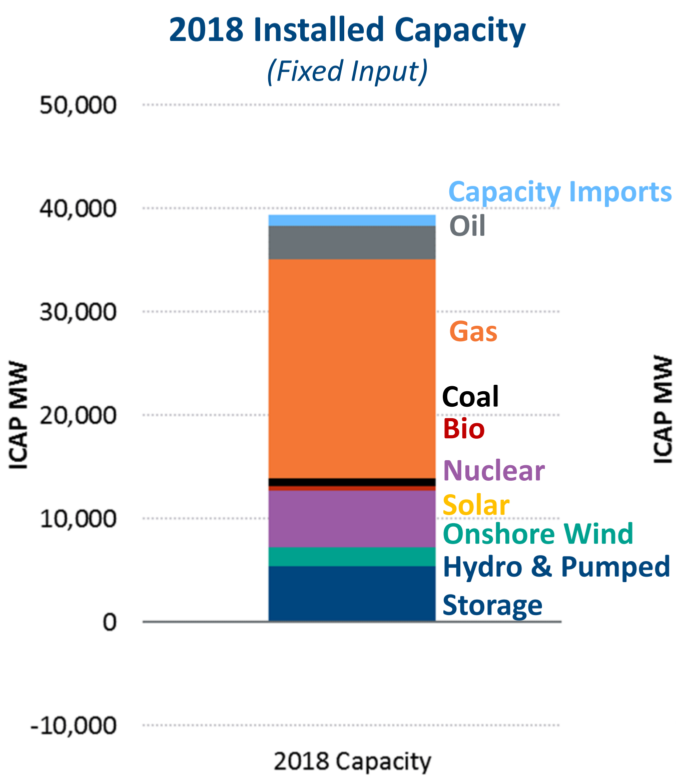
- **Base Case:** Gas ST is marginal, so 400 MW policy exemptions displaces 400 MW of gas ST retention
- **High Load Case:** Generic offer floor is marginal in all cases, so 400 MW exemptions results in +400 MW generic offer floor resources (and vice versa)

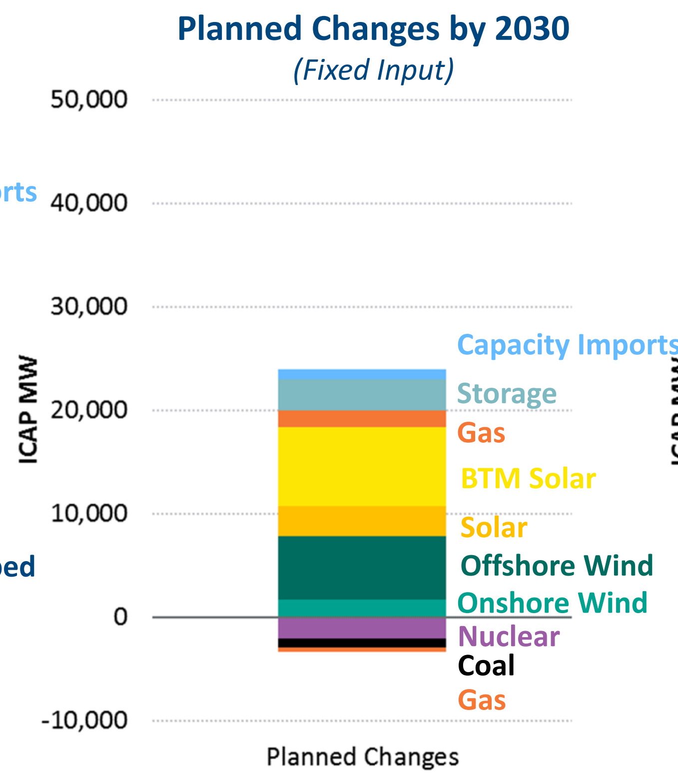


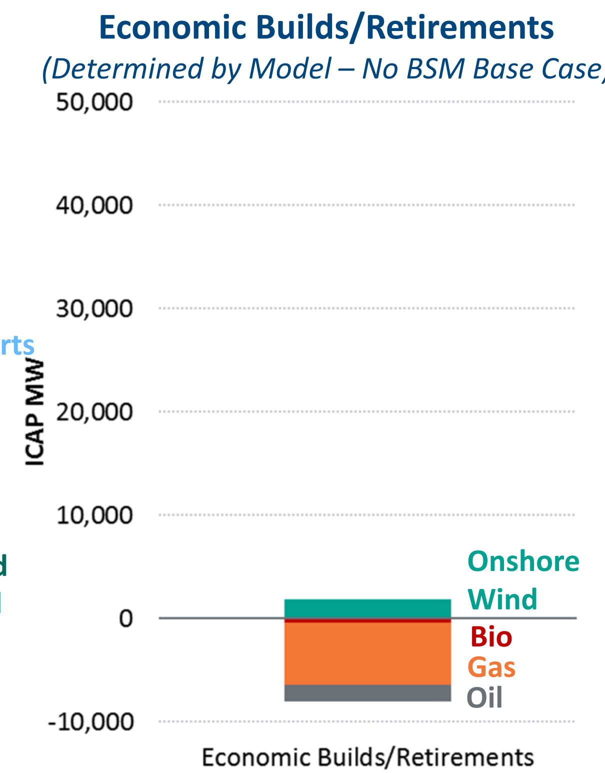
Base Case Detailed Results

Base Case Supply Mix

Existing generation is consistent with the 2019 Gold Book, and planned capacity changes are based on signed CES contracts and CARIS study assumptions. The model economically retires old plants and builds new clean ones to meet any remaining gap to reach CLCPA 70% target







Note: Model determines if 2018 existing supply resources will retire by 2030.

Note: Model determines economic resource builds needed to reach CLCPA targets (incremental to planned changes).

Capacity Subject to Mitigation
before considering exemptions or clearing

Mitigated Non-Emitting Capacity by Zone (ICAP MW)

Blue shading subject to Status Quo BSM

Expanded BSM applies to blue and teal

	2018 Capacity	Planned/Assumed 2019-2030 Additions/Retirements (Fixed Input)					Economic Additions (Determined by Model)		Total Capacity by 2030
		Zone A-E	Zone F	Zone G-I	Zone J	Zone K	Zone A-E	Zone F-K	
Hydro & PS	5,436	0	0	0	0	0	0	0	5,436 **
Onshore Wind	1,739	1,710	0	0	0	0	1,814	0	5,263
Offshore Wind	0	0	0	0	4,320*	1,778	0	0	6,098
Solar	77	2,677	0	284*	0	0	0	0	3,038
Storage	0	660	240	270	1,350	480	0	0	3,000
Nuclear	5,399	0	0	(2,054)	0	0	0	0	3,345
Capacity Import	1,100	0	0	0	1,000	0	0	0	2,100
Total	**13,751**	**5,047**	**240**	**(1,500)**	**6,670**	**2,258**	**1,814**	**0**	**28,280**

Notes: 2018 installed capacity informed by 2019 Gold Book. Planned/assumed builds are informed by 2019 CARIS study assumptions and signed CES contracts based on 2018-2019 CES contract summary document and recent 2019 Tier 1 solicitation.
* 816 ICAP MW OSW in Zone J and 880 ICAP MW OSW in Zone K procured in 2018 solicitation and 284 MW solar in Zone GHI exempt in both Status Quo and Expanded BSM. See the following slide for assumptions regarding status quo renewable exemptions as assumed consistent with the April 20 NYISO filing.
** Half of existing hydro fleet assumed to be mitigated under Expanded BSM.

Status Quo Exemptions

The quantity of possible public policy resource exemptions under the NYISO's April 20 proposed approach is subject to considerable uncertainty. Our updated analysis assumes ~550 UCAP MW of exemptions (with a sensitivity analysis of +/-400 UCAP MW)

- Given the large uncertainties, our assumed quantity of exemptions is intentionally abstracted from specific predictions such as which resources may be deemed "policy-driven" retirements
- Overall quantity is consistent with outlook for load growth, retirements, and demand curve width
- In "high exemptions" scenario, we further assume that some storage becomes exempt through other means (such as via Part A or Part B tests)

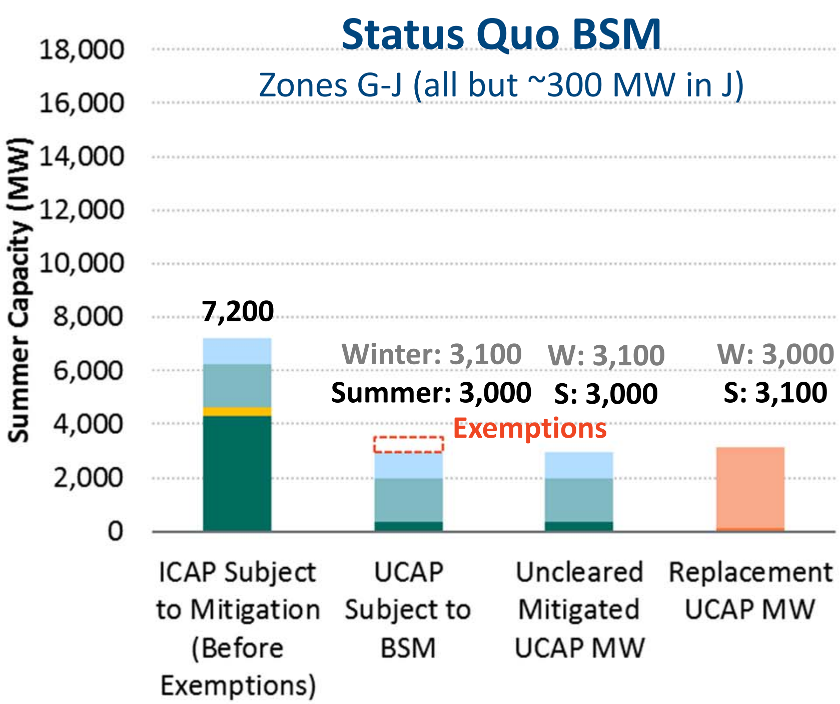
Status Quo Exemptions by Zone

	Zones G-I	Zone J	Zones G-J
Summer UCAP Supply (UCAP MW)			
Offshore Wind	0	848	848
Storage	270	1,350	1,620
Solar	41	0	41
Capacity Imports	0	1,000	1,000
Exemptions (UCAP MW)			
Public Policy Resources	41	507	548
Remaining Mitigated Resources (UCAP MW)			
Offshore Wind	0	341	341
Storage	270	1,350	1,620
Solar	0	0	0
Capacity Imports	0	1,000	1,000

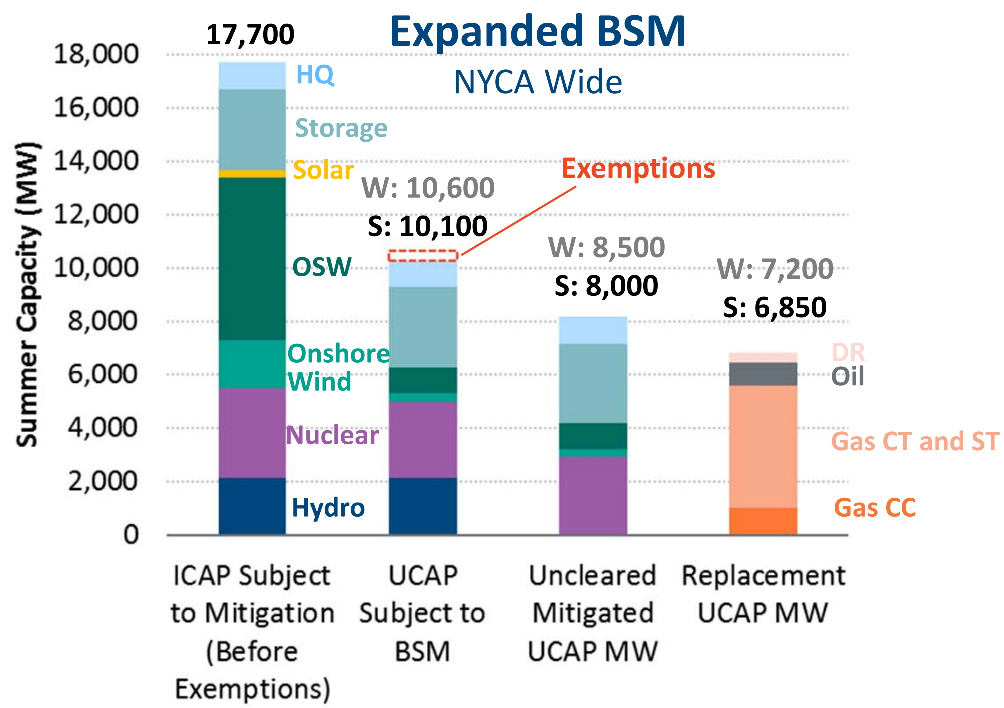
Summary of Mitigation and Market Response Quantities (NYCA-Wide)

In Status Quo BSM, essentially all of the ~3,000 summer UCAP MW uncleared mitigated capacity is replaced by retained gas ST

In Expanded BSM, ~1,150 summer UCAP MW of the 8,000 summer UCAP MW uncleared mitigated capacity is *not* replaced (mostly Upstate), resulting in a higher capacity prices and costs



Mitigated capacity in Zones G-J only under Status Quo, mostly OSW and storage in Zone J that is replaced by retained gas ST plants. UCAP values reflect average ELCC. Capacity numbers are approximate.



Mitigated capacity in all zones. Mitigated OSW and storage in Zones J and K largely offset by retained gas resources. All UCAP values shown reflect average ELCC. Capacity numbers are approximate.

Prices and Customer Costs

Zone J Capacity prices remain similar across all structures as retiring gas ST resources are marginal. Capacity prices in A-F increase significantly in Expanded BSM as more renewables and nuclear resources are mitigated, thus retaining more thermal plants that would otherwise retire

Wholesale Market Prices

Zone	Capacity Market Prices (2030 $/kW-month)			Delta Above (Below) No BSM (2030 $/kW-month)	
	1. Status Quo	2. Expanded BSM	3. No BSM	1. Status Quo	2. Expanded BSM
A-E	$3.65	$8.13	$3.69	($0.04)	$4.44
F	$3.65	$8.13	$3.69	($0.04)	$4.44
G-I	$6.05	$8.13	$6.05	($0.00)	$2.08
J (NYC)	$12.33	$12.32	$12.34	($0.01)	($0.02)
K (LI)	$13.05	$13.88	$13.05	$0.00	$0.83
	Energy Market Prices (2030 $/MWh)			**Delta Above (Below) No BSM (2030 $/MWh)**	
A-E	$28.02	$27.99	$28.02	$0.00	($0.03)
F	$30.28	$30.23	$30.28	$0.00	($0.05)
G-I	$30.36	$30.33	$30.36	$0.00	($0.03)
J (NYC)	$30.36	$30.33	$30.36	$0.00	($0.03)
K (LI)	$32.19	$32.19	$32.19	$0.00	($0.00)

Cost of BSM

Category	Customer Costs Delta Above (Below) No BSM (2030 $ million)	
	1. Status Quo	2. Expanded BSM
Wholesale Market Cost	**$25**	**$941**
Energy	$0	($7)
Ancillary Services	$0	($0)
Capacity	$25	$949
Contract Costs	**$434**	**$842**
Total Customer Cost	**$458**	**$1,784**
Excluding Nuclear Make-Whole	$457	$1,622

Modeling Approach and Assumptions

Brattle GridSIM Model

Inputs

Supply

Existing resources
Fuel prices
Investment/fixed costs
Variable costs

Demand

Representative day hourly demand
Capacity needs

Transmission

Zonal limits
Intertie limits

Regulations, Policies, Market Design

Capacity market
Carbon pricing
Procurement mandates

GridSIM Optimization Engine

Objective Function

Minimize NPV of Investment & Operational Costs

gridSIM

Constraints

- Market Design and Co-Optimized Operations
  - *Capacity*
  - *Energy*
  - *Ancillary Services*
- Regulatory & Policy Constraints
- Resource Operational Constraints
- Transmission Constraints

Outputs

Annual Investments and Retirements

Hourly Operations

System and Customer Costs

Supplier Revenues

Emissions and Clean Energy Additions

Market Prices

Demand Assumptions

- "Base Load" load assumptions align with 2019 CARIS study input assumptions for 2030
- "Base Load" assumes lower demand than 2019 (156 TWh gross load)
- Modeled "High Load" based on State Team input that assumes greater load than 2019

2030 Demand Assumptions

	Base Load	High Load
Scenarios	Base Case No-Nuclear	High-Load
Annual Gross Load	145 TWh	169 TWh
Gross Peak Load	30 GW	35 GW
Net Peak Load	28 GW	33 GW

Sources and Notes:
"Base Load" annual gross load assumptions are based on 2019 CARIS study. Used ratio of 2019 annual gross load and CARIS annual gross load to convert 2019 gross peak loads to 2030 gross peak loads on zonal level.
"High Load" annual gross load assumptions based on State Team's input. Calculated peak loads based on annual gross load ratio as described above.
Netted out assumed 7,542 MW of solar BTM (based on 2019 CARIS study) valued at ~27% summer capacity value from gross peak load to calculate net peak load (similar to Gold Book assumptions).
2019 load data taken from NYISO OASIS data.

Supply Cost Characteristics

- **Resources' fixed O&M costs** affect supply elasticity and BSM price impacts. Sources:
  - *New Gas CCs, CTs*: 2020 costs from Demand Curve Reset (DCR); 2.2% cost inflation rate
  - *New Gas STs*: 2019 costs and cost decline rate from 2019 NREL ATB (0% to -1%/year real)
  - *New wind, solar, storage*: 2019 costs and cost decline rate from 2019 NREL ATB (0% to -7% /year real)
  - *Existing Nuclear*: 2019 costs from NEI (constant real), plus assumed $280/kW-year refurbishment cost adder in 2030
  - *Existing CTs, STs*: FOM from NYISO 2018 SOM Report
  - *Other existing thermal:* FOM assumed 2x new units
  - *All other existing:* Same FOM as new resources
  - *Zone J and K*: FOM assumed 1.3 – 2.7x higher than upstate based on DCR zonal cost ratios
- **Offshore wind** tied to either zone J or K
- **Utility-scale PV and onshore wind** cannot be built in zones J or K

2030 Resource Cost Assumptions

	Upstate New Resource Capital Cost *2030$/kW*	Upstate New Resource FOM *2030$/kW-yr*	Upstate Existing Resource FOM + Refurb Costs *2030$/kW-yr*	Variable O&M *2030$/MWh*
Natural Gas				
Combined cycle	$2,300	$27	$54	$2
Combustion turbine	$1,200	$14	$25	$7
Steam turbine	$5,000	$43	$72	$11
Battery Storage				
4-hour duration	$1,100	$26	$26	$6
Solar PV				
Utility scale	$1,100	$13	$13	$0
Wind				
Offshore (downstate)	$4,600	$107	$107	$0
Onshore	$1,600	$50	$50	$0
Nuclear				
Single-unit	N/A	N/A	$602	$3
Multi-unit	N/A	N/A	$491	$3

Sources and Notes:

Includes interconnection and network upgrade costs. NREL 2019 ATB, NYISO DCR Model 2019-2020 and 2020-2021 , and NEI Nuclear Costs in Context.
VOM for storage resources reflect efficiency losses. Existing FOM for nuclear includes refurbishment costs.
FOM costs for existing STs and CTs were based on average GFC shown in Figure 16 of the 2018 State of the Market Report; FOM costs for existing Gas CTs upstate assumed to be half of those for existing Gas CTs in Zone K.
FOM costs for other existing thermal resources were assumed to be 2x that of comparable new ones, informed by EPA Integrated Planning Model document.
Nuclear refurbishment costs informed by refurbishment costs for nuclear plants in Ontario.

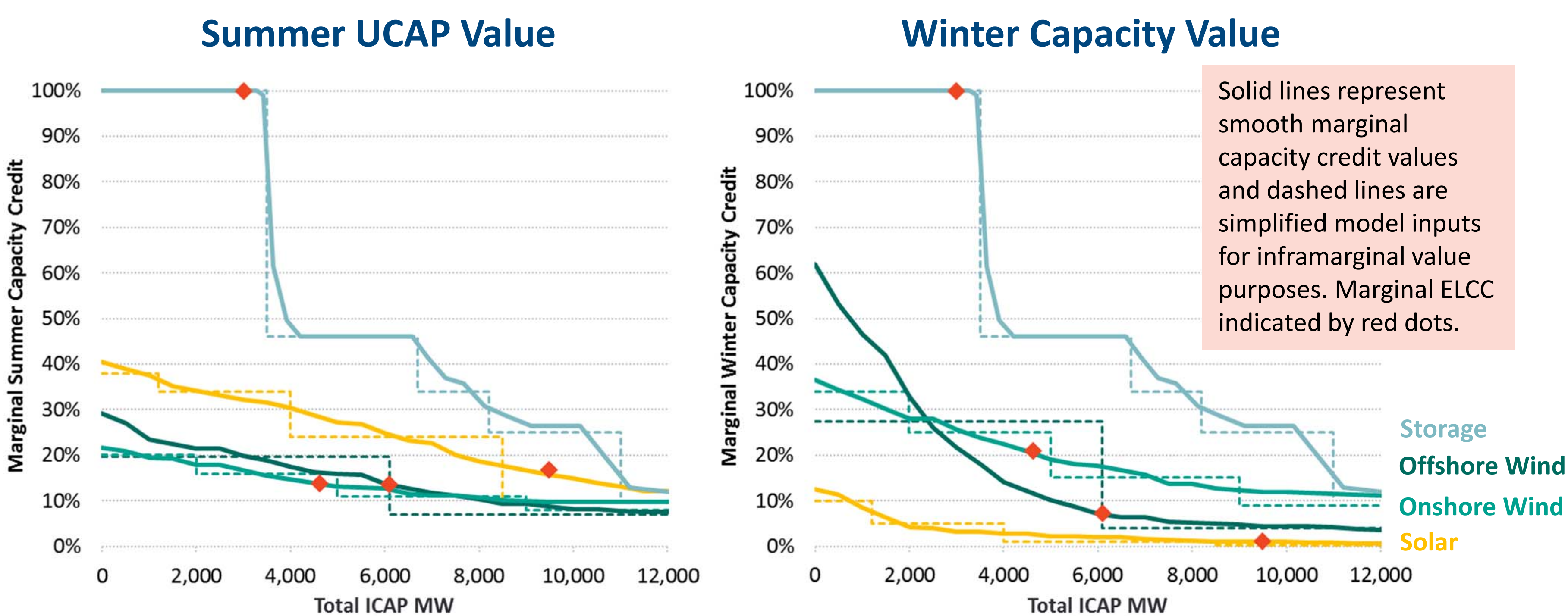
ELCC Modeling Approach

Supply Resource	Concept	Methodology
Wind and Solar Resources	Generation of new wind and solar additions is correlated with previously deployed resources. New resources therefore provide less marginal capacity value than previously added resources.	1. Across 8760 hours, identify 100 top NYCA net load hours 2. Calculate wind UCAP value as avg. output in those hours 3. Repeatedly change the MW of wind installed, all else equal 4. Each time, find top 100 net load hours and the avg. output 5. Repeat process for offshore wind and solar; for each one, hold other variable technologies at likely 2030 levels
Storage Resources	Energy storage can change the “shape” of peak net load periods, flattening and elongating peak periods. As more storage is deployed, longer discharge durations are therefore required to provide the same capacity value.	1. Across 8760 hours, analyze MW of storage required to reduce NYCA net peak load by 1 MW 2. Calculate UCAP value as 1 MW peak reduction / MW storage required 3. Increase amount of storage assumed, holding all else equal. Simulate effect of increased storage on net peak load 4. Repeat steps 1 – 3 across many storage deployment levels 5. Repeat process for storage of different durations

Base Case UCAP Value Curves
modeled based on NYCA-wide net load

As the penetration increases, marginal effective load-carrying capability (ELCC) decreases.

Note: this analysis may have conservatively low ELCCs for renewables, based on hourly data with lower output than future installations are likely to achieve (and that does not capture diversity across sites for OSW); on the other hand, this analysis uses NYCA-wide net load without considering how transmission constraints could reduce value more quickly.



Note: solar capacity credit curves include assumed 7,542 MW of solar BTM already on the grid (based on CARIS study assumption).

Assumptions on BSM Applicability

Resource Type	BSM in Structure 1. Status Quo		BSM in Structure 2. Expanded BSM	
	Zones G-J	Rest of System	Zones G-J	Rest of System
Nuclear	N/A	N/A	N/A	3,345 ICAP MW
OSW	1,740 ICAP MW (assumed 507 UCAP MW exemption in Zone J applies to OSW)		3,504 ICAP MW (assume 816 ICAP MW of already signed contracts exempt)	898 ICAP MW (assume 880 ICAP MW of already signed contracts exempt)
Existing Solar and Onshore Wind	No		No	No
New Utility Scale Solar and Wind	Any new utility scale solar or onshore wind in Zones G-J		All new utility scale solar and onshore wind	
Bulk Storage	1,620 ICAP MW		1,620 ICAP MW	1,380 ICAP MW
Existing Hydro	No		50 ICAP MW	2,085 ICAP MW
Tier 2 Renewables	No		No	No
New HQ Imports	1,000 MW in Zone J		1,000 MW in Zone J	N/A
Demand Response	No		No	No
Fossil Resources	No		No	No

Source: Assumptions on applicability provided by NYSERDA/DPS staff.

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Attachment D

Kathleen Spees & Samuel Newell, *The Economic Impacts of Buyer-Side Mitigation in New York ISO Capacity Market*, The Brattle Group,

FERC Docket No. EL21-7-000 (Nov. 18, 2020)

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Cricket Valley Energy Center LLC and	)	
Empire Generating Company LLC	)	
v.	)	**Docket No. EL21-7-000**
New York Independent System	)	
Operator Inc.	)	

WRITTEN TESTIMONY
OF

DR. KATHLEEN SPEES AND DR. SAMUEL A. NEWELL

The Economic Impacts of Buyer-Side Mitigation in New York ISO Capacity Market

Our names are Dr. Kathleen Spees and Dr. Samuel A. Newell. We are employed by The Brattle Group as Principals. On behalf of the Natural Resource Defense Council, the Sustainable FERC Project, Earthjustice, Sierra Club, American Wind Energy Association, Alliance for Clean Energy New York, and Advanced Energy Economy, we submit this affidavit on The Economic Impacts of Buyer Side Mitigation in the New York Independent System Operator (NYISO) Capacity Market.

Our qualifications as experts derive from our extensive experience evaluating capacity markets and related market design questions. Our experience working for system operators across North America and internationally has given us a broad perspective on the practical implications of nuanced capacity market design rules under a range of different economic and policy conditions.[1] In New York, we have conducted analyses on behalf of the New York State Energy Research and Development Authority (NYSERDA) and the New York State Department of Public Service (NYSDPS) to analyze the costs of Buyer Side Mitigation (BSM) and potential expansions thereof, and to evaluate alternatives to BSM. We are also very familiar with the Minimum Offer Price Rule (MOPR) in PJM Interconnection, LLC's (PJM) capacity market that Cricket Valley Energy Center (CVEC) LLC and Empire Generating Company LLC (the "Complainants") seek to

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1 We have worked with regulators, market operators, and market participants on matters related to resource adequacy and investment incentives in PJM Interconnection, ISO New England, New York, Ontario, Alberta, California, Texas, Midcontinent ISO, Italy, Russia, Greece, Singapore, and Western Australia.

emulate. We have supported PJM by conducting every one of its periodic reviews of its capacity market and have developed design recommendations for competitive and self-supply exemptions to MOPR.[2] Dr. Newell has submitted testimony to the Federal Energy Regulatory Commission (FERC) on behalf of PJM in developing economic estimates of offer floor prices to implement the MOPR rules in that region. Dr. Newell has also submitted testimony on behalf of the Competitive Markets Coalition group of generating companies seeking to strengthen PJM's MOPR in its original purpose to prevent and mitigate the exercise of buyer market power.[3]

Dr. Spees is an economic consultant with expertise in wholesale electric energy, capacity, and ancillary service market design and analysis. She earned a Ph.D. in Engineering and Public Policy, an M.S. in Electrical and Computer Engineering from Carnegie Mellon University, and a B.S. in Mechanical Engineering and Physics from Iowa State University. Dr. Newell is an economist and engineer with more than 20 years of experience analyzing and modeling electricity wholesale markets, the transmission system, and ISO/RTO market designs. He earned a Ph.D. in Technology Management and Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science and Engineering from Stanford University, and a B.A. in Chemistry and Physics from Harvard College.

2 See our four independent reviews of PJM's capacity market and associated design parameters published in 2008, 2011, 2014, and 2018. The most recent of these is: Samuel A. Newell, David Luke Oates, Johannes P. Pfeifenberger, Kathleen Spees, J. Michael Hagerty, John Imon Pedtke, Matthew Witkin, and Emily Shorin, *Fourth Review of PJM's Variable Resource Requirement Curve*, Prepared for PJM Interconnection L.L.C., April 19, 2018.

3 FERC Docket No. ER13-535-000, filed "The Competitive Markets Coalition's Supporting Comments, at Attach. A, Affidavit of Dr. Samuel A. Newell on Behalf of the 'Competitive Markets Coalition' Group Of Generating Companies," supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model, December 28, 2012 ("Affidavit of Dr. Samuel A. Newell on Behalf of the Competitive Markets Coalition").

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Executive Summary

The original and proper economic purpose of buyer-side mitigation (BSM) rules is to protect the market from the exercise of buyer market power: schemes where large net buyers or their representatives offer a small amount of uneconomic supply into the market below cost in order to suppress market clearing prices.[4] By taking a loss on that small position, a large net buyer could then benefit from a much larger short position in the market. The BSM was designed to prevent this behavior. The concept was to ensure that entities with the incentive and ability to engage in manipulative price suppression will be unable to do so by requiring their capacity market offers to reflect their full costs. Thus uneconomic new resources sponsored by large net buyers would fail to clear (or would set the prices at a higher level) and prevent the would-be gaming entity from achieving the benefits of manipulative price suppression. Symmetrical rules are imposed on large net sellers of capacity in order to prevent them from exercising economic or physical withholding.

More recently, the BSM has been inappropriately repurposed to exclude from the capacity market resources that earn revenues for supporting states', communities', or private consumers' clean energy mandates or sustainability goals; and the Complainants want to extend BSM's application even further along these lines. There is no sensible economic rationale for applying BSM to resources that are developed or maintained to address the harms of climate change or other environmental externalities. The policy support awarded to such resources reflects their environmental value; these resources are not "uneconomic" and their introduction is not in any way related to schemes of manipulative price suppression with uneconomic entry that the BSM was designed to address. Further, expanding BSM does not "level the playing field" as Complainants claim, since it does not privatize the costs of environmental externalities and does not attempt to undo the effects of all local, state, and federal policies that have always shaped the resource mix, including supporting the development of existing fossil plants and reduced the delivered cost of fossil fuels.

Applying BSM to clean energy resources may prevent them from clearing the market, with several undesirable effects. First, it will deprive clean energy resources of revenues reflecting the capacity value they provide, which will interfere with the State's fulfillment of its clean energy mandates. Second, it will favor the retention of uneconomic fossil-fired generation that are not needed for reliability, further conflicting with the State's transition. Third, it will produce higher market clearing prices exceeding the level corresponding to actual supply conditions and effectuate a large wealth transfer from customers to incumbent suppliers. And fourth, contrary to the Complainants' claims, BSM's application to policy resources will eventually render the market unsustainable as these distortions become larger over time under New York's statutory mandate to achieve 70% renewable electricity by 2030 and 100% clean electricity by 2040.[5] The end state of applying BSM to clean energy resources would be a capacity market that excludes a large majority of the fleet, with market clearing outcomes having no relationship to underlying supply and demand fundamentals.

These distortions would be amplified by the Complainant's proposal to expand the applicability of BSM to all policy-supported resources throughout the state and to increase their minimum offer prices in the capacity auctions. Instead, BSM should be changed in the other direction to limit its

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[4] Federal Energy Regulatory Commission (FERC), Docket No. EL07-39-000, "Order Conditionally Approving Proposal" at PP 100–P100106, March 7, 2008.

[5] State of New York, Senate – Assembly, S. 6599 – A. 8429, "Article 75, Climate Change," June 18, 2019.

applicability to its original purpose. The most appropriate capacity price is the one that will prevail after the elimination of BSM rules from policy resources, such that the capacity market can continue supporting economic entry and exit by providing an accurate reflection of capacity surplus or shortfall.

THE APPLICATION OF BUYER-SIDE MITIGATION TO POLICY RESOURCES IS BASED ON FLAWED ECONOMIC LOGIC

The Complainants in this proceeding and their witness Dr. Roy Shanker claim that BSM should be applied to policy resources in order to protect the capacity market from the effects of state policies.[6] Similar to prior economic arguments presented to the FERC, the Complainants assert that state-supported resources inappropriately suppress capacity market prices, thus undermining investment signals and ultimately system reliability. Their proposed remedy is to apply BSM to policy resources, thus restoring prices to the levels that would prevail in the absence of state policies.

The Complainants' economic arguments are incomplete and flawed. A corrected economic analysis should consider that:

- State environmental policies address a well-understood market failure to reflect environmental externalities. The environmental value of policy-supported resources should not be considered an illegitimate distortion of markets that must be excluded, but rather a correction that is needed to achieve a more efficient outcome;
- The "correct" price for capacity is one that aligns supply and demand, not the price that would prevail in the absence of state policies as the Complainants' BSM proposal would aim to produce;
- Capacity markets with sloping demand curves cannot simultaneously produce low prices and poor resource adequacy as the Complainants assert;
- Broad application of BSM to policy resources will amplify (not mitigate) the regulatory risks affecting capacity investments; and
- Merchant generation investors operate in a market and regulatory context that has always required them to face uncertainties associated with a wide range of energy and environmental regulations at the federal, state, and local levels; these policies and associated economic subsidies have always influenced the resource mix (some in favor of incumbent fossil resources and others in favor of clean energy resources). Merchant investors should never have expected to be indemnified against risks associated with these policies (nor should they be required to return revenues to customers when policy changes favor their own investments).

Overall, the Complainants aim to solve a problem that doesn't exist. Their primary concern appears to be that as incumbent fossil generation owners, they no longer expect to earn a satisfactory return on their investments. While certainly a concern for incumbents, low capacity prices are not a problem from a societal or market design perspective. Low prices are simply a reflection of market conditions indicating ample capacity supply; they appropriately signal that no

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[6] FERC, Docket No. EL21-7-000, "Complaint and Request for Fast Track Processing," at p. 14, October 14, 2020 ("Complaint").

new capacity is needed and that high-cost existing resources should retire. In fact, prices that are low enough to signal retirement of aging fossil resources will be necessary to achieve an orderly transition from fossil resources and toward clean energy.

The BSM should be maintained only for its narrow original purpose of addressing manipulative price suppression, not applied to clean energy policy resources. That will enable the capacity market to continue offering competitive benefits by producing accurate price signals that align with market fundamentals.

APPLYING BUYER-SIDE MITIGATION TO POLICY RESOURCES WILL INTERFERE WITH NEW YORK'S STATUTORY MANDATE TO TRANSITION TO A 100% CLEAN ELECTRICITY GRID BY 2040

New York's Climate Leadership and Community Protection Act (CLCPA) mandates a transition to 70% renewable electricity by 2030, 100% clean electricity by 2040, an 85% reduction in economy-wide greenhouse gas emissions, and another 15% greenhouse gas reduction via offsets by 2050.[7] Applying BSM to policy resources will interfere with the State's CLCPA mandates by excluding clean energy resources from clearing in the capacity market and causing the uneconomic retention of high-cost fossil fuel resources that would otherwise retire.[8] Specifically:

- Under the Status Quo BSM rules, approximately 7,200 MW of installed capacity (ICAP) (3,050 MW, reported as the annual average of summer and winter unforced capacity (UCAP) ratings) of policy resources will be subject to BSM by 2030. We project that none of that capacity will clear the capacity market. Instead, approximately 3,050 UCAP MW annual average of aging steam turbine plants will clear that would otherwise retire.
- Under an Expanded BSM rule with the same primary elements as proposed by the Complainants, approximately 17,700 ICAP MW (10,350 UCAP MW annual average) of policy resources would be subject to BSM by 2030. Approximately 8,250 UCAP MW would fail to clear the capacity market, replaced by approximately 7,025 UCAP MW annual average of primarily gas- and oil-fired power plants.

Overall, the application of BSM to policy resources would interfere with the transition to a 100% clean electricity mix. A more appropriate capacity market design would acknowledge the reality of the clean energy transition, support the orderly retirement of aging fossil plants, and adapt to an increasing reliance on clean energy resources to support resource adequacy.

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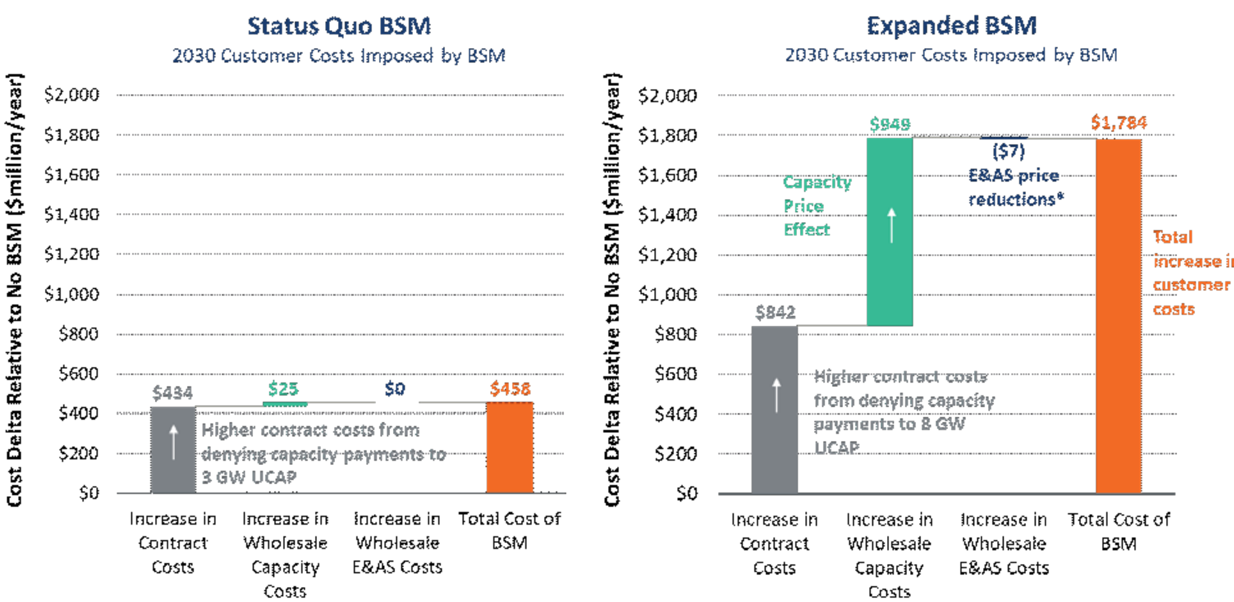
7 State of New York, Senate – Assembly, S. 6599 – A. 8429, "Article 75, Climate Change," June 18, 2019.

8 The assumptions and methodology used to develop the analytical results reported here are described in more detail in Exhibit B (Spees, *et al.*, "Quantitative Analysis of Resource Adequacy Structures," Prepared for NYSERDA and NYSDPS, July 1, 2020); the assumptions adopted at the time reflected our expectations regarding how various dockets and appeals would be resolved regarding the "Status Quo BSM" rules and an "Expanded BSM" rules assumptions and associated uncertainties. Those assumptions remain largely consistent with the current NYISO capacity market rules and the Complainants' proposal. These results were originally developed on behalf of the New York State Energy Research and Development Authority, and the New York Department of Public Service. *See* Exhibit B, Spees, *et al.*, "Quantitative Analysis of Resource Adequacy Structures," Prepared for NYSERDA and NYSDPS, July 1, 2020.

APPLYING BUYER-SIDE MITIGATION TO POLICY RESOURCES IMPOSES UNECONOMIC EXCESS COSTS ON CUSTOMERS AND ON SOCIETY AS A WHOLE

Misapplying BSM to policy resources will impose significant excess costs on customers, amounting to approximately $460 million per year under Status Quo BSM rules or $1,780 million per year by 2030 under the Expanded BSM rules proposed by the Complainants, as summarized in Figure 1. These excess costs appear in two ways: (1) as an increase in capacity prices affecting all transactions; and (2) as an increase in contract payments to policy resources because they are deprived of capacity market revenues that go instead to unnecessary substitute resources. Excess costs would be imposed immediately upon application of the Expanded BSM rules as approximately 3,100 UCAP MW of nuclear resources would immediately be affected. The costs would grow over time alongside the scope of the clean energy transition; by 2030 the excess customer costs would rise to approximately $950 million per year from inflated capacity prices plus $840 million per year in excess contract payments under the expanded BSM rules proposed by the Complainants. The excess contract payments reflect paying capacity to non-policy resources that are not actually needed to meet the reliability targets underlying the capacity market, rather than paying the policy resources for the capacity they provide.

FIGURE 1: CUSTOMER COSTS FROM IMPOSING BSM ON POLICY RESOURCES BY 2030



Sources and Notes: * Energy and AS prices decrease in some cases because excess capacity depresses prices in tight hours; and because higher contract payments (due to lack of capacity payments) cause energy prices to be more negative in over-generation hours. Costs reported in 2030$. *See* Exhibit B at p.7.

The primary beneficiaries of BSM are incumbent capacity market sellers, who enjoy elevated capacity prices and gain a greater share of capacity market sales. However, the net benefits enjoyed by these incumbent capacity suppliers would be much smaller than the excess costs imposed on consumers. By 2030, Status Quo BSM and Expanded BSM would increase capacity sellers' revenues by $460 million and $1,790 million annually; but their costs would also increase to maintain the excess capacity cleared by roughly $450 million and $790 million annually.[9] Hence their producer surplus would increase by only approximately $10 million and $1,000 million per year. That increase in producer surplus mostly reflects a wealth transfer from

[9] These estimates rely entirely upon the public presentation attached hereto as Exhibit B.

customers. The increased costs to maintain unneeded supply represents excess societal expenditure that benefits neither consumers nor producers.

TO CONTINUE OFFERING BROAD BENEFITS TO CONSUMERS, COMPETITIVE MARKETS MUST ALIGN WITH AND SUPPORT ENVIRONMENTAL POLICY GOALS

Far from "protecting" the capacity market, maintaining and expanding the application of BSM to policy resources will erode and eventually eliminate the benefits of the competitive capacity market. With Status Quo BSM and particularly with an Expanded BSM, the disconnect between market fundamentals and market clearing prices will grow as greater quantities of policy-supported clean energy resources come online over the coming years. The consequential growth in excess customer costs, societal costs, and wealth transfers to incumbent fossil plants will rapidly become unsustainable from a policy and economic perspective.

A better path forward is to eliminate the application of BSM to energy policy-supported resources so that the wholesale markets can help meet clean energy and reliability needs at low cost. The wholesale electricity markets are already largely set up to do so, with the energy, ancillary services, and capacity markets (absent BSM) complementing the State programs that reward resources for their environmental attributes. Together, all of these markets can guide the supply mix to cost effectively meet the state's energy and environmental needs, and can do so even more effectively with continued enhancements.

Regulators, the NYISO, and stakeholders in New York and other regions are already considering several enhancements to better align wholesale markets with states' environmental policies, including enhanced carbon pricing, enhanced energy and ancillary service market designs, and more accurate accreditation of storage and intermittent resources in the capacity market.[10] These reforms may take some time but will ultimately support the evolution of toward a fit-for-purpose wholesale market for the decarbonized grid.

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10 For example see NYISO, "Reliability and Market Considerations for a Grid in Transition," December 20, 2019; and NYISO, "IPPTF Carbon Pricing Proposal Prepared for the Integrating Public Policy Task Force," December 2018.

A. Background on Buyer Side Mitigation and its Proposed Expansion in New York

The New York capacity market is a centralized competitive platform within which the market operator procures the quantity of resources needed to meet regional resource adequacy or reliability needs. The NYISO uses an administrative demand curve to procure the quantity of capacity that it estimates will be needed to ensure that bulk system supply shortages are infrequent, occurring no more often than once in ten years in expectations (the "1-in-10" reliability standard). Import-constrained subregions such as New York City are represented by separate demand curves establishing a minimum quantity of capacity that must be located in that subregion.

Capacity sellers offer their resources into the market at the minimum price they are willing to accept to come online or stay in the market. For any given resource, the minimum price they are willing to accept is driven by a number of factors including primarily: (a) costs associated with bringing new supply into the market or maintaining an existing facility that needs re-investment; and (b) minus any anticipated net revenues that could be earned from energy markets, ancillary service markets, or other revenue sources (such as sales of renewable energy credits (RECs), steam, or gypsum). Many sellers would also adjust their capacity offer price based on any bilateral sales agreements for capacity or any co-products they may produce and based on their long-term view of future energy and capacity prices. Sellers that are able to pre-sell most of their capacity or energy through bilateral contracts would typically offer at a zero price, as would most sellers that have already come online and have few going-forward capital investments.

Capacity prices are set at the intersection of sellers' capacity market supply offers and the administrative demand curve in each location and system-wide. Under this framework, the market produces prices consistent with supply-demand conditions. The market produces low prices when the region has more than enough supply to meet resource adequacy needs; it produces high prices when capacity supply is scarce. For the two decades since New York's capacity market was implemented, it has produced competitive prices that signal the need for new entry; attracted new entry from generation, imports, and demand response when needed; and allowed for the orderly retirement or net exports of higher-cost resources when supply was long.[11]

One of the design elements of the capacity market is a comprehensive framework for mitigating the potential for both supply-side and demand-side market power abuses. The framework consists of a number of inter-related design elements. Chiefly, the monitoring and mitigation framework includes: (a) *sell side mitigation* provisions that impose capacity price offer caps that are intended to limit the ability of large net sellers from manipulative economic or physical withholding that could inflate market prices; (b) largely symmetrical *buy side mitigation* provisions that similarly impose offer floors on large net buyers to prevent manipulative suppression of market prices; and (c) *independent monitoring and mitigation* activities to regularly review market efficiency and competitiveness. Together, these comprehensive monitoring and mitigation rules support price formation that market participants can anticipate will largely reflect economic fundamentals and supply-demand conditions, without being driven by the private interests of a player with large buy- or sell-side market share.

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[11] Potomac Economics, Market Monitoring Unit for the NYISO, "2019 State of the Market Report for the New York ISO Markets," May 2020, at p.57 (Capacity Market Results and Design).

The original purpose of BSM rules in the context of the overall market monitoring and mitigation framework was to prevent manipulative price suppression. The rules were intended to prevent entities with a large net buyer position from exercising buy-side market power. Without such a rule, a large net buyer could be in a position to game the capacity markets by bringing a small quantity of incremental capacity supply into the market, offering the supply at a zero price, and producing a low capacity price. In some cases, a large buyer supporting new entry would not be a problem. For example, if the incremental supply is relatively low cost and thus a better deal than purchasing generalized capacity from the market. However, the purchase can be viewed as manipulative price suppression if the incremental supply is very high cost, higher than the but-for capacity price that would otherwise have materialized. In that circumstance, the buyer would develop uneconomic supply (taking a financial loss on a small quantity of high-cost capacity supply) in order to achieve a lower capacity price (thus benefitting the much larger net buy position). This behavior is, by definition, manipulative because the uneconomic incremental supply resource is not a rational resource to develop when viewed in isolation. The incremental supply is pursued only for the purpose of suppressing market prices below the competitive levels that would prevail from individually rational entry and exit.

To prevent this manipulative price suppression, the BSM would restate the offer price from zero to a higher level based on the minimum offer price rule (MOPR). The higher MOPR price prevents this scheme from producing price suppression and makes it less likely that the resource in question would clear the capacity market. When applied to large net buyers and their supported resources, the BSM rules privatize the cost of any potentially uneconomic investments, while holding other parties in the market harmless. More importantly, the existence of the rule is intended to disincentivize the manipulative behavior and associated economic waste from taking place at all.

In New York, the current or "Status Quo BSM" rules currently apply to the downstate capacity zones G-J, apply only to new resources, and apply a MOPR price at the lesser of 0.75× Mitigation net Cost of New Entry (CONE) or a resource-specific value.[12] The rules further allow for Part A and Part B exemption tests that allow some resources to avoid the application of the BSM, if a forecast of future market conditions indicates that the supply will be needed or likely to clear the future capacity auctions; if the resources appear likely to clear then they can gain an exemption from BSM. This limited application of BSM is associated with the original narrow purpose of the rule, which was to prevent manipulative price suppression; these capacity zones were the only locations within which the market structure indicated that any large net buyer might have the incentive and ability to exercise market power.

The FERC has recently expanded the role of BSM in New York and in other regions to impose a MOPR more broadly to apply to resources that earn policy payments. The large majority of these resources in New York and other regions are those awarded policy payments in recognition of their contribution toward achieving states' environmental policies. The Complainants propose to expand BSM in New York further through several reforms: (1) to increase the applicable MOPR price to a technology-specific value in all cases (which will typically be much higher than the current default value); (2) to eliminate Part A and Part B exemptions that can allow certain resources to avoid BSM application in the delivery year; (3) to apply BSM broadly across all capacity zones in New York; and (4) to apply BSM to existing as well as new resources, with the

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12 "Mitigation Net CONE" is an administrative estimate of the levelized cost of new supply that could be attracted into the capacity market.

greatest effect being the immediate application of BSM to approximately 3,100 UCAP MW of existing nuclear resources.[13] Overall these changes will substantially expand the scope of capacity resources affected by BSM.

The mechanics of BSM as applied to policy resources are illustrated in Figure 2. The left panel illustrates clearing outcomes if all capacity resources are allowed to offer at their preferred offer price. Most (though not necessarily all) policy resources will typically offer at a zero. These resources earn the (large) majority of their revenues through energy market and policy payments reflecting their environmental value; thus, these resources will be developed and online regardless of the capacity price. So, they would typically choose to offer at zero in the capacity market. Fossil plants and other capacity resources would offer at the minimum capacity price needed to earn a return on going-forward investments.[14] Clearing prices are set at the intersection of supply and demand.

When BSM is applied to a policy resource, its offer price is increased from zero to a higher level for the purposes of auction clearing. As illustrated in the right panel of Figure 2, the higher BSM-based price will re-order the capacity market offer supply curve, make it less likely for the policy resource to clear the market, and cause higher clearing prices.

When applied to policy resources, the mechanics of the BSM are identical as compared to the application in the context of manipulative price suppression. However, the economic purpose and impact are entirely different. Unlike in the context of manipulative price suppression, BSM, when applied to policy resources, is not intended to prevent the investments from taking place. The policy investments will proceed regardless of BSM because they are developed for the primary purpose of addressing climate change (they are not developed as a means of achieving capacity market price suppression, and would not be a cost-effective means of achieving price suppression). Thus the exclusion of these resources from clearing the market will not prevent such investments from taking place.

Another difference between the contexts of manipulative price suppression and policy resources is the scope and scale of the affected resources. In the context of manipulative price suppression, the typical behavior would be that the buyer would endure a small economic loss from developing a small quantity of uneconomic capacity resources, with that small loss more than offset by the gains to the much larger buy-side position. The scope of BSM tend to cover a small volume of supply. In the context of policy resources, there is no expectation that the quantities of excluded resources will remain small. In fact, regardless of BSM, these resources should be expected to become the large majority of the New York capacity market as the state proceeds toward its 100% clean electricity mandate.

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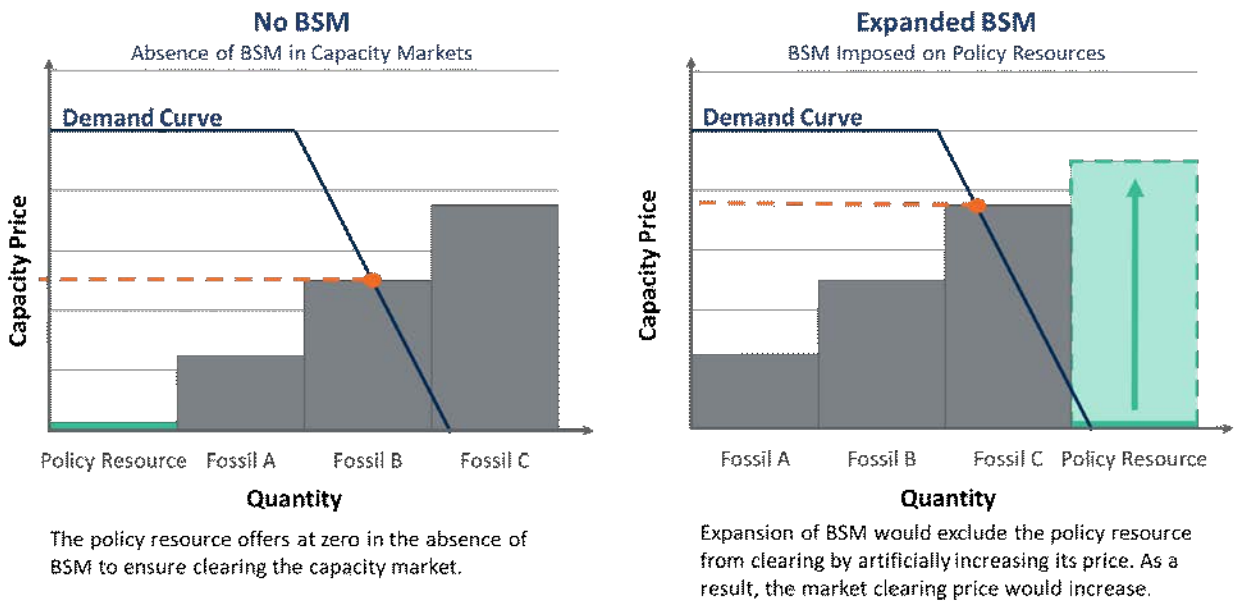
13 *See* Exhibit B at p. 12, consistent with Complaint, at Attach. A, Shanker Affidavit, at p. 6.

14 In the non-forward New York market, these other resources may also offer at zero but would tend to enter or exit the market in advance based on whether projected clearing prices would be sufficient to earn a return. The effect on realized prices is the same as in our stylized description here if we assume that market participants have perfect foresight of future market conditions.

FIGURE 2: EXPANSION OF BSM WOULD INCREASE THE CLEARING PRICE



B. The Application of Buyer Side Mitigation Rules to Policy Resources is Based on Flawed Economic Logic

The Complainants present an economic analysis that largely reflects analysis that has previously been presented to the FERC on this same topic. The stated concerns are as follows. States such as New York are attracting large quantities of new resources to meet clean energy goals through a variety of programs and contract solicitations that the Complainants consider to be "subsidies."[15] Because these activities can reduce near-term capacity market prices and/or displace "non-subsidized" resources, BSM advocates argue that it is necessary to protect wholesale capacity markets from the price-suppressive impacts of state policies. They argue that without intervention, market prices will be inappropriately low, merchant capacity suppliers will not earn adequate returns on investment, this would discourage new capacity from entering the market, and thus threaten future reliability. Their proposed remedy is to use BSM on policy resources to restore capacity prices to the "correct" level*, i.e.*, the price that would have prevailed in the absence of the state policies.

The rationale that the Complainants provide for applying BSM to policy resources is based on incomplete and flawed economic logic. A corrected economic analysis reveals a simpler truth: that the "correct" capacity price is the one that accurately reflects underlying fundamentals of supply and demand. This is the accurate price that should signal when and where capacity investments are needed (and when high-cost resources can retire). The logical conclusion under this corrected economic analysis is that BSM should be eliminated from application to policy resources so that capacity prices can be utilized to rationalize supply with demand.

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[15] We do not subscribe to the view that such state programs and/or solicitations should be considered "subsidies" in the traditional sense, nor that subsidies are inappropriate or inherently problematic if they are pursued in light of policy goals. Instead, we see the introduction of clean energy policies as generally providing compensation for environmental externalities not otherwise provided for by the market itself.

B.1. State Policies Address Well-Understood Market Failures Such as Environmental Externality Costs

The complaint quotes Commissioner Danly observing, "these [BSM] exemptions will, regardless of the policy objectives they may seek to achieve, impede a market's ability to set prices that accurately reflect market forces." But prices "reflecting market forces" alone do not ensure economic efficiency where major externalities exist, as in this case. A negative externality is a negative side effect of an economic activity that adversely affects a party not involved in the transaction. The adversely affected third party has no influence over whether the transaction takes place, but is nevertheless harmed. Environmental externalities such as those caused by greenhouse gas and air quality emissions from fossil fuel-fired power plants are the classic textbook example of externalities.[16] Once emitted into the air, greenhouse gases cause a number of adverse effects on residents, businesses, and environment in New York, nationally, and globally in the present day and for hundreds of years.[17] Other pollutants such as NO_X, SO_X, and particulates cause even more immediate detrimental health outcomes such as asthma and early death.[18] Absent policies to address these externalities, neither the purchaser of the power (NYISO in this case) nor the producer of the emissions (the power plant owner) pays the full cost associated with these negative externalities.[19] Such unpriced or underpriced externalities will tend to be produced at a quantity that exceeds the economically efficient level from a societal perspective. The consequence of ignoring these environmental externalities is that market pricing alone would drive resource investments and operations toward an inefficiently large quantity of fossil fuel-fired power plants, imposing inefficiently large externality costs.

Externalities are by definition not "market forces," but rather market failures. Under their existence markets fail to allocate the resources efficiently and the current market price would not be the "correct" one. As a general matter, public policies can address externalities and market failures in one of two ways: one is *command-and-control* policies that regulate behavior directly; the other is to develop market-based policies that align private incentives with social efficiency.[20]

Environmental externalities can be incorporated into electricity markets through policy mechanisms, whether through emissions pricing mechanisms (*e.g.,* carbon pricing) that charge

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16 N. Gregory Mankiw, *Principles of Microeconomics*, 5th ed. Mason, (OH: South-Western Cengage Learning, 2009), p. 204.

17 United States Environmental Protection Agency, "Climate Change Indicators: Greenhouse Gases," accessed on November 16, 2020.

18 Michael Guarnieri, John R Balmes, "Outdoor Pollution and Asthma," The Lancet 383 (9928): 1581–1592. doi:10.1016/s0140-6736(14)60617-6 (2014).

19 The Regional Greenhouse Gas Initiative (RGGI) has imposed some costs on emitters, but the allowance prices are far below the Social Cost of Carbon adopted by the New York Public Service Commission (NYPSC) for setting zero-emissions credit (ZEC) prices and VDER tariffs, and likely further below the State's willingness to pay for carbon reduction as implied by its aggressive decarbonization goals. In setting ZEC prices, the NYPSC adopted a social cost of carbon of $50.11/short ton (in nominal dollars) for Tranche 3, which runs from April 2021 through March 2023. By comparison, the most recent RGGI auction at the time of this writing cleared at $6.82/short ton on September 2, 2020 (available at https://www.rggi.org/auctions/auction-results/prices-volumes). *See also* NYPSC, Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, "Order Adopting a Clean Energy Standard," at 136, August 1, 2016.

20 N. Gregory Mankiw, *Principles of Microeconomics*, 5th ed. Mason, (OH: South-Western Cengage Learning, 2009), p. 154–210.

emitters and indirectly reward non-emitters and/or through clean energy attribute payments that reward non-emitters directly. Carbon pricing can take many forms, from a tax or charge approach that sets a price per ton emitted; to a cap-and-trade approach that sets a cap on emissions and lets the market determine the price of allowances; to a hybrid, such as RGGI that is nominally "cap-and-trade" but that includes adjustable caps to serve as price collars. In all of these cases, carbon pricing raises the cost for emitters to produce, making them less competitive and raising market clearing prices for energy; non-emitters earn the higher prices without being charged. Clean energy attribute payments work more directly by paying non-emitters to produce carbon-free energy. They are usually provided through long-term contracts that support clean resources, as in New York's ZEC and REC programs. The mechanisms used to support clean energy resources will continue to evolve as the State, NYISO, and stakeholders continue to assess the most effective and efficient opportunities to support the clean energy transition, as discussed in Section E below.

Many economists (and some pro-BSM) advocates argue that a carbon pricing mechanism would be a better way to address these environmental externalities and enable all resources to compete based on market prices for energy (that account for carbon-related externalities), capacity, and ancillary services. For example, FERC recently held a technical conference on carbon pricing; and the Electric Power Supply Association recently sponsored a study by Energy + Environmental Economics (E3) presenting carbon pricing as the most efficient way for states to achieve their environmental objectives.[21] We agree with many of the arguments in favor of carbon pricing, but caution that electricity sector carbon pricing alone may be an incomplete solution in the context of States' environmental mandates.

We too believe that carbon pricing would help support the state's objectives cost-effectively, through resource-neutral competition that accurately signals where and when clean energy production displaces the most carbon emissions, while also appropriately rewarding storage and higher-efficiency gas-fired generation that partially reduce emissions. The ideal is for a carbon pricing regime to apply uniformly and comprehensively in its geographic scope (across state and national borders) and in its coverage of all economic sectors. However, without this comprehensive scope, carbon pricing could induce unintended effects such as leakage or disincentives to electrify heating and transportation demand. In the case of NYISO's proposal to charge carbon emitting generators in New York for their emissions at a state Commission-determined social cost of carbon, our work showed that proposed border adjustments and allocation of carbon revenues to customers could largely avoid these adverse effects.[22] These results are not necessarily generalizable to other ISO markets or if carbon prices become much higher, but carbon pricing should continue to be pursued, especially at a national and economy-wide level in order to achieve carbon abatement in the most cost-effective fashion.

However carbon pricing should not be presented as the only "legitimate" or "efficient" policy option for incorporating carbon externalities into electricity markets. Even if carbon pricing is pursued, the practical reality is that carbon prices alone may not be set high enough to support sufficient investment to meet mandated clean energy targets in the timeframe required by State

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[21] E3, "Least Cost Carbon Reduction Policies in PJM," at p. 9, March 28, 2020.

[22] Samuel A. Newell, Roger Lueken, Jürgen Weiss, Kathleen Spees, Pearl Donohoo-Vallet, Tony Lee, The Brattle Group, "Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals," August 10, 2017.

laws.[23] Clean energy attribute payments, competitive clean energy solicitations, and customer-backed contracts for clean energy resources are all alternative approaches that can be pursued for addressing environmental externalities, each with advantages and disadvantages relative to carbon pricing in terms of timing, economic efficiency, risk allocation, and implementation feasibility. Further, different communities and customers (within New York) or state governments (in other regions) will place different values on their deemed cost of carbon emissions and so will not be able to establish a single market-wide carbon price. Overall, we anticipate that a combination of carbon pricing and clean energy attribute payments of some form together will be utilized to achieve New York's 100% clean energy mandate. Given the interplay and partial substitutability between RECs and carbon pricing, it is curious that the BSM advocates would view energy revenues incorporating carbon to be legitimate but RECs and ZECs not to be. While they are not the same mechanism, they both serve to address environmental externality costs by affecting the relative revenues of emitting and non-emitting generators, and they have similar effects on capacity market prices. For example, a high enough carbon price would retain high-cost nuclear plants just like a ZEC payment does, so it is difficult to see why the capacity market treatment should be so radically different if using one mechanism or combination of mechanisms versus another.

A more consistent approach is to acknowledge that states, communities, and customers have a legitimate interest in addressing environmental externalities. As the demand side of wholesale electricity markets, customers and their elected representatives have the proper role of establishing how much they are willing to pay to address environmental externalities and what combination of contracts and policies they wish to use to express that value. An efficient marketplace should aim to assist states and customers by providing options for achieving their environmental goals at the lowest possible cost.

B.2. The "Correct" Capacity Price is the One that Aligns Supply with Demand (Not the Price that would Prevail in the Absence of State Policies)

The efficient outcome in a market, or set of interconnected markets, is that which maximizes social welfare: the sum of consumer and producer surplus. Absent environmental externalities and with market participants acting competitively, this outcome would result at the price where the marginal cost of supply (to producers) is equal to the marginal value of additional consumption (to consumers). However, when environmental externalities are introduced, the intersection of (private) supply and demand *will not represent the efficient outcome.* This inefficient outcome is the one that the complainants seek to re-establish with the expanded MOPR. Instead, the correct capacity price is that which aligns supply and demand, given other policies and/or markets that policymakers have identified as necessary to address the externality.

Compensating non-emitting resources for their environmental value lowers their net cost of providing capacity (regardless of whether that compensation is achieved through carbon pricing or clean energy payments). Clean energy resources correctly appear more competitive as capacity providers, just like resources with high energy and ancillary services value, and they should be

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[23] Especially as the emissions target tightens toward zero, the carbon price would have to be very high to continue to favor investment in new clean resources over running existing fossil-fired generators in a small number of hours. For example the finding that "carbon taxes alone are unlikely to produce emissions pathways in line with the net-zero emissions targets by 2050," in Larsen, *et al.*, Expanding the Reach of a Carbon Tax: Emissions Impacts of Pricing Combined with Additional Climate Actions, October 2020.

allowed to clear the capacity market and be recognized for the resource adequacy value they contribute to the system.

If the capacity market consequently produces low prices, this is correctly signaling an oversupply of capacity, that no more investments are needed for resource adequacy, and that the least valuable resources should retire. Reliability will not be threatened by replacing traditional capacity with clean capacity, as clean resources will be assigned capacity ratings reflecting only the reliability value they actually provide. In fact, NYISO's resource accreditation for intermittent resources is already a fraction of their nameplate capacity and will decline as their market share increases. Thus, as the clean energy transition proceeds it will take greater quantities of wind, solar, and battery supplies to replace a single retiring gas plant. Through this continuously-adjusting displacement rate, reliability can be maintained over the course of the transition. For the same reasons, the market (absent BSM on policy resources) can provide the right price signals and result in efficient outcomes with the least-cost set of economic retirements, entry, and retention of resources needed to maintain resources adequacy.

Forcing policy resource offers upward through BSM rules would generally prevent them from clearing. It would result in an artificially high capacity clearing price and induce inefficient behaviors and uneconomic incentives: it would retain costly existing supply that would otherwise retire, attract costly new supply that is not needed, and dis-incentivize customers from utilizing more electricity given inflated prices that signal a false scarcity of capacity supply. Thus, the application of BSM to policy resources causes the capacity market to depart from supply-demand fundamentals.

The inefficiency of the outcome is especially apparent considering that policy resources will be developed and operate regardless of whether or not they clear the capacity market. Thus the BSM distorts the capacity market by inducing the procurement of additional capacity to meet reliability objectives. The capacity market would simulate a fictional reality as if the policy resources that help meet demand every hour of the year did not exist. Under that fictional scenario, the reliability value of the policy resource in question would be ignored, would not be paid for, and thus would need to be made up for through the purpose of capacity from other suppliers. This scenario becomes perverse when applied to a state such as New York with a 100% clean electricity mandate. All policy-supported resources that physically supply resource adequacy could be excluded from being counted in the capacity market, while the capacity market would remain a multi-billion-dollar-per-year "shadow market" that exists primarily to pay resources that are not actually needed for resource adequacy.

Overall, the Complainants offer a solution to a non-problem. The grievance from the standpoint of incumbent fossil generators is that their resources will eventually become uneconomic in a region with a significant clean energy mandate. Such resources will not enjoy the same revenues they would in a world where emissions do not matter.

However, low prices are not a problem from a more holistic market design, reliability, or economic perspective. Low prices would be produced only when supply is long, new entry is not needed, and retirements can be accommodated. Applying BSM to policy resources creates a fundamental disconnect between market pricing outcomes that deviate from the underlying fundamentals of supply (including that associated with state policy resources) and demand (as expressed through resource adequacy requirements).

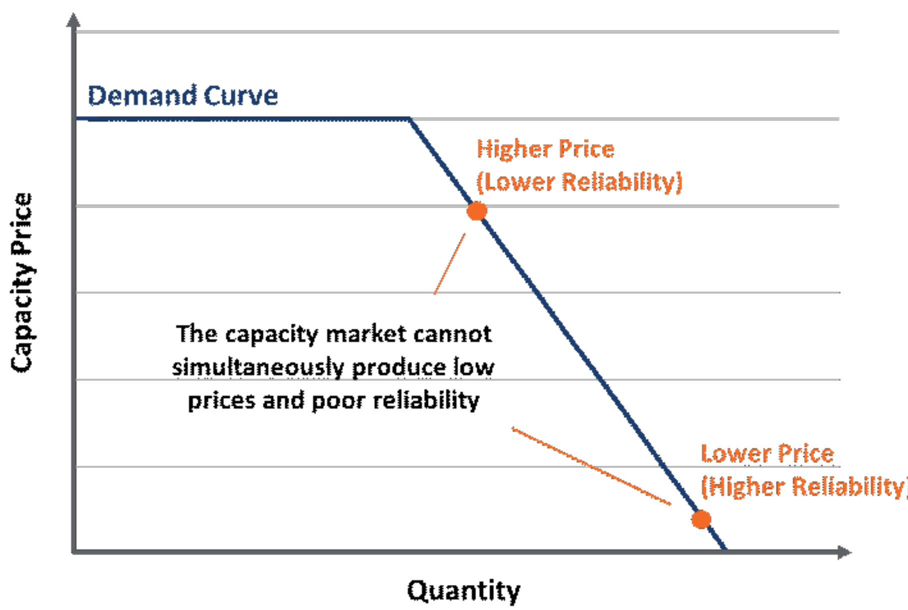
B.3. Capacity Markets with Sloping Demand Curves Cannot Simultaneously Produce Low Prices and Poor Resource Adequacy

The Complainants and other BSM advocates have expressed a misguided concern that the low prices that may prevail due to growth in policy resources will threaten reliability by discouraging investment.

As shown in Figure 3, this concern is illogical in the context of a capacity market with a downward-sloping demand curve that reflects the required reserve margin and the incremental value of additional supply beyond that reserve margin. By its nature, the downward sloping demand curve simply cannot produce market outcomes with low prices and low reliability at the same time. If prices are low due to the entry of policy resources, this means that there is ample supply of capacity on the system. In this long market condition the low capacity prices signal that high-cost resources should retire and new entry is not needed. If the supply-demand balance tightens, prices will rise and signal the need to attract and retain scarce capacity. Thus the Complainants' concern that low prices will produce low reliability is unfounded (and a mathematical impossibility).

This is not to say that reliability is not a concern in the clean energy transition. As noted above, intermittent resources whose unavailability may be correlated across the fleet (*e.g.,* low wind days, or low solar insolation periods such as nighttime) provide less and less incremental resource adequacy value as their penetration increases. Capacity markets must recognize that fact through resource accreditation that accurately reflects resources' contribution to system reliability. Beyond the context of capacity markets discussed in this testimony, other aspects of the wholesale electricity markets including energy, ancillary service, and transmission planning rules may be needed to ensure robust pricing and operations in the context of different resource patterns and capabilities throughout the clean energy transition.

FIGURE 3: CAPACITY MARKETS WITH DOWNWARD-SLOPING DEMAND CURVES CANNOT SIMULTANEOUSLY PRODUCE LOW PRICES AND POOR RESOURCE ADEQUACY



B.4. Broad Application of Buyer-Side Mitigation to Policy Resources will Amplify (Not Mitigate) Regulatory Risks

BSM advocates have argued BSM is necessary to mitigate regulatory risk surrounding capacity investments. We acknowledge that capacity investments do face more regulatory risk in a world with environmental policies than one in which policies never change; and that imposition of increasingly-stringent policies will more usually disadvantage higher-emitting resources. The application of BSM to clean energy policy resources undoes some of that effect, by elevating capacity prices to the level that would prevail absent the policy resources. It would also retain the same capacity as in world without the policy-supported clean energy resources. As long as BSM is maintained, it will benefit incumbent fossil resources and might even attract investment in new gas-fired resources (in both cases, securing more capacity than is needed for reliability).

However, elevated prices should not be conflated with less-risky prices. We do not believe the BSM reduces regulatory risk or provides an efficient basis for attracting new investment. On the contrary, a market whose price is artificially inflated by a rule as controversial and economically inefficient as BSM is unsustainable. Investors will not count on the price premiums produced by such a rule to be sustainable over the long term. They would have to realize that, over time, the pressure to eliminate BSM would only increase as mounting quantities of policy resources are excluded from the market and the BSM-supported price and capacity deviate further from reflecting actual supply and demand conditions. Customers will ask why they are paying so much to support excess capacity, as if it were needed to meet the (already conservative) resource adequacy objectives underlying the capacity market. They will notice that the excess capacity they are supporting is primarily fossil fuel generation that contravenes state clean energy policy goals with wide popular support, and they will demand change. For these reasons, capacity markets that fail to accommodate policies that states are committed to pursuing cannot form the basis for a sustainable market design that supports investment.

Capacity markets can better support merchant investment when needed, with lower regulatory risk, if they do not apply BSM to clean energy policy resources. Such a market reflecting actual supply and demand conditions will send just the right price signals to maintain resource adequacy at least cost. Merchant investors will still face market and regulatory risks, including risks from environmental policies changing in the future. States can mitigate these risks by setting environmental policies on a long-term stable basis, as New York has done through its CLCPA that specifies goals through 2050. Investors can then view these policies as part of the fundamentals against which they can plan their business strategies.[24]

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[24] For example, the Grid Evolution study we performed for NYISO did not incorporate BSM, and it showed how merchant investment in capacity could complement a future with large quantities of policy-supported clean energy resources added. The simulated market retained enough existing capacity and attract enough storage investment to maintain resource adequacy through 2040. It showed that, as vast amounts of wind and solar generation are added to meet clean energy goals, they will continue to contribute capacity value but at a declining marginal rate reflecting their correlated intermittency. Other non-intermittent resources will still needed to support system reliability, and market prices should adjust to signal dispatchable capacity to stay online or enter the market. In our central scenario where policy-driven electrification of transportation and heating sectors increases demand, the simulated market even attracted investment in new dispatchable "gas-fired" generation capacity, assuming it could generate using "renewable natural gas" that counts as non-emitting. *See* R. Lueken, et al., "New York's Evolution to a Zero Emission Power System," prepared for NYISO and presented to the NYISO stakeholders, June 22, 2020.

B.5. Merchant Investors Operate Amidst Wide-Ranging Energy and Environmental Policies from which They Never Should have Expected to be Indemnified

The Complainants express concern that certain merchant investments are not earning the return on investment that they anticipated. They assert that "state subsidy issues" are producing "lower than expected capacity prices caused by uneconomic retention of state subsidized generation facilities."[25]

While poor investment returns are certainly a concern for the particular investors referenced here, this is not a concern from a market design perspective. Merchant generation investors operate in a market and regulatory context that has always included environmental regulations from which they should not expect to be indemnified any more than they should be charged when regulations work in their favor. Favorable policy developments for merchant investors in gas-fired generation such as the Complainants have enjoyed in New York include the finalization of the State's arrangement with Entergy to shut down the Indian Point Energy Center, agreements to retire the state's remaining coal plants, rules to eliminate high-NO_X-emitting peaking plants from Downstate New York, and possible future expansion of electricity demand from policy-driven electrification of the heating and transportation sectors. Natural gas-fired generators also benefit from various tax policies and ratepayer-funded gas transportation infrastructure that have lowered the delivered costs of their fuels.[26]

New York's decarbonization policies underlying the complaint mostly do not help natural gas-fired plants that are major emitters of carbon dioxide. But the state has long discussed its environmental priorities, particularly the need to address climate change. Investors in new power plants should have anticipated policies to effectuate a transition in the generation fleet. It is misleading to suggest, as the Complainants have, that investors in Empire and CVEC could not or should not have foreseen the development of public policies that are unfavorable to the interests of large carbon-emitting power plants. Consider the following record of New York's steady long-term march toward the policies it has now:

- As early as 2002, the New York state government expressed concern in its State Energy Plan regarding the reliance of the state on gas-fired electricity and established a goal to increase renewable energy by 50% as a percentage of total load served by 2020, aiming to move from 10% of demand met by renewable energy to 15% by 2020.[27] In 2004, the New York PSC had adopted the more aggressive RPS goal of 25% renewable energy by the end of 2013.[28] Investment in Empire Energy was made against this backdrop, wherein New York had clearly displayed its commitment to promoting renewable energy.
- In 2010 the RPS goal was amended to 30% by 2015.[29]

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25 Complaint at p. 33.

26 For example, *see* Doug Koplow, "Testimony on behalf of Sierra Club in Protest on Behalf of Clean Energy Advocates", in FERC Docket No. ER18-1314, May 7, 2018.

27 New York State, "2002 New York State Energy Plan," at Section 1–3.

28 NYPSC, Case 03-E-0188, *Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard,* "Order Regarding Retail Renewable Portfolio Standard," September 24, 2004.

29 NYPSC, Case 03-E-0188, *Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard,* "Order Establishing New RPS Goal and Resolving Main Tier," January 8, 2010.

- In December 2015, Through Reforming the Energy Vision (REV), New York State Government called for 80% GHG emissions reduction by 2050 and 50% of electricity demand to be met by renewables by 2030.[30]
- On January 25, 2016 the NYSDPS staff published a white paper regarding what was to become the Clean Energy Standard, which aimed to meet the goals set forth by Governor Cuomo in 2015. In this white paper they discussed the plan to institute a ZEC in order to support "a smooth emission-free transition from nuclear to non-nuclear resources in the event that energy prices are not able to support the continued financial viability of the plants during their license lives."[31] The ZEC program was established formally on August 1, 2016, when the New York PSC adopted the Clean Energy Standard.[32] It was not until January 24, 2017, nearly one year after NYSDPS staff published the white paper regarding the ZEC program that CVEC closed on financing for developing its generating facility.[33]

But even if the Complainants could not have anticipated the full extent or particulars of the CLCPA, these policies are within the State's mandate to protect public health and are part of the context in which the Complainants chose to invest. They chose to bear the risks and rewards associated with changing market conditions and regulations, and there is no reason to indemnify them through BSM. Doing so would distort the market, as explained above, and impose unnecessary costs on consumers.

B.6. BSM Should Be Applied for Its Narrow Original Purpose of Mitigating Market Power Abuses (Not Repurposed to Undo the Effects of State Policies)

BSM is an appropriate mechanism for its original purpose of preventing manipulative price suppression.[34] In that context BSM has a valid economic rationale: to prevent net-short entities and their representatives from sponsoring uneconomic investments to suppress prices, benefit themselves in the short run (at the expense of other market participants), and induce economic deadweight losses.[35] Applied for that original purpose, BSM rules work together with many other elements of a comprehensive monitoring and mitigation framework that assures market participants that market outcomes will be competitive, reflecting supply-demand fundamentals.[36]

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30 REV, "What You Need to Know," December, 2015.

31 NYSPSC, Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, "Staff White Paper on Clean Energy Standard," at p. 30, January 25, 2016.

32 NYPSC, Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, "Order Adopting a Clean Energy Standard," August 1, 2016.

33 *See* "Advanced Power AG Closes Financing of $1.584 Billion Energy Center in Dover, New York" *Business Wire*, January 24, 2017.

34 *See:* FERC, Docket No. EL07-39-000, "Order Conditionally Approving Proposal" at PP 100–P100106, March 7, 2008.

35 This deadweight loss is the cost of the uneconomic resources in excess of the value they provide. The costs of the resources developed in order to suppress prices exceeds the cost of the resources displaced that would otherwise have cleared the market.

36 *See* Affidavit of Dr. Samuel A. Newell on Behalf of the Competitive Markets Coalition: FERC, (supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model).

This valid economic rationale for BSM does not apply in the context of policy-supported clean energy investments:

- Clean energy policy investments are pursued to address climate change, not as a means to suppress capacity prices.
- State-supported investments in clean energy are not uneconomic just because they need payments beyond what they would earn through wholesale electricity markets alone. These policy incentives correct for the market failure to reflect the costs of environmental externalities associated with climate change and public health.
- Applying BSM to clean energy policy resources does not prevent uneconomic behavior (as it does when applied to mitigate manipulative price suppression schemes); rather, it actually *causes* uneconomic behavior by incentivizing the retention of uneconomic, unneeded resources. And as we show later the greatest impact would be to retain exactly those aging fossil plants that the clean energy investments are intended to displace.

Clean energy policies will have a number of effects in the electricity sector and broader economy. Capacity markets, like all other markets, may inevitably be affected by these policies. The overall outcome of an effective policy to mitigate climate change will be to reduce the amount of greenhouse gas emissions produced and to guide the resource mix away from fossil and toward a mix that meets energy and reliability needs with cleaner resources

C. Applying Buyer Side Mitigation to Policy Resources Will Interfere with New York's Statutory Mandate to Transition to a 100% Clean Electricity Grid by 2040

To evaluate the impacts of applying BSM to policy resources, we conducted a simulation analysis of the New York capacity market in a 2030 study year with three scenarios with "No BSM," "Status Quo BSM," and "Expanded BSM" rules.[37] In the No BSM case, we estimated the prices, clearing outcomes, and resulting customer costs under a capacity market design in which BSM is eliminated from application to policy resources. In the Status Quo BSM case, we simulated current BSM rules that are applied only to new policy resources in the downstate G-J region of the NYISO capacity market with an offer floor at the minimum of 0.75 × mitigation Net CONE and a technology-specific value. In the Expanded BSM case, we examined rules consistent with Complainants' proposal to expand BSM to existing and new policy resources throughout New York, and increasing the applicable offer floor to technology-specific MOPR values.

Our analysis shows that the overall effect of applying BSM to state policy resources is to exclude policy resources from clearing the capacity market and induce the uneconomic retention of fossil plants. Both of these outcomes pose barriers to achieving the State's mandate to eliminate carbon emissions from electricity generation by 2040, and interim mandates before then.

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[37] We conducted this analysis on behalf the New York State Energy Research and Development Authority, and the New York Department of Public Service. The assumptions and methodology used to develop the analytical results reported here are described in more detail in Exhibit B. *See* Spees, *et al.,* "Quantitative Analysis of Resource Adequacy Structures," Prepared for NYSERDA and NYSDPS, July 1, 2020.

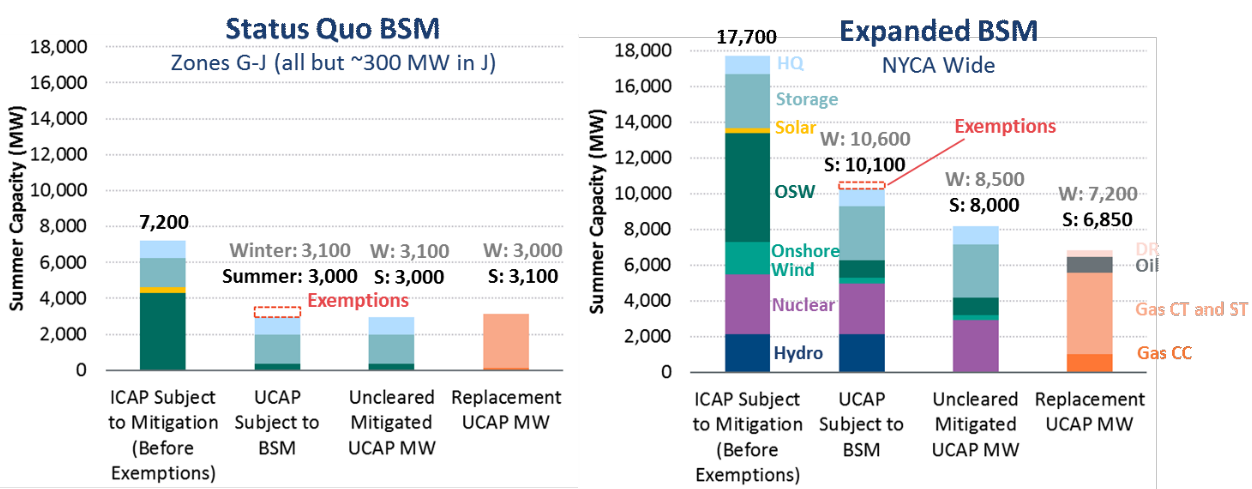
C.1. Approximately 8,250 MW of Clean Resources Would be Excluded from Clearing the Capacity Market by 2030

Figure 4 summarizes our estimates of the quantity of policy resources that could be subject to BSM rules in the New York capacity market by 2030 under Status Quo and Expanded BSM rules. We further report the shares of these resources that we estimate would be likely to clear the capacity market and those that would not. Specifically, we estimate that:

- Under the Status Quo BSM rules, approximately 7,200 ICAP MW (3,050 UCAP MW, reported as the annual average of summer and winter capacity ratings) of policy resources will be subject to BSM by 2030. We project that none of that capacity will clear the capacity market because their BSM offer floors would price them out of the market.
- Under an Expanded BSM rule similar to the one proposed by the Complainants, approximately 17,700 ICAP MW (10,350 UCAP MW annual average) of policy resources would be subject to BSM by 2030. Approximately 8,250 UCAP MW annual average would fail to clear the capacity market.

Failing to clear such a large quantity of existing capacity resources will limit progress in the transition to a clean energy grid by reducing the formal role of policy resources to contribute to resource adequacy and reliability needs.

FIGURE 4: PROJECTED IMPACTS OF BSM ON CAPACITY MARKET CLEARING BY 2030



Sources and Notes: *See* p. 14, Exhibit B.

C.2. Approximately 7,025 MW of Fossil Resources Would be Uneconomically Maintained by an Expanded BSM

As also shown in Figure 4 above, policy resources excluded from clearing the capacity market would likely be replaced primarily by uneconomic fossil plants that would otherwise retire. Under Status Quo BSM assumptions, we estimate that 3,050 UCAP MW annual average of aging, high-emitting gas-fired steam turbine plants would be retained that would otherwise retire. Under Expanded BSM, a full 7,025 UCAP MW annual average of unneeded and uneconomic capacity resources would be retained, including primarily gas- and oil-fired plants, as well as a small amount of demand response.

C.3. In a Region with Significant Clean Electricity Goals, Any Sensible Market Must Recognize Clean Supply While Enabling the Orderly Retirement of Fossil Plants

In a region with significant clean electricity goals, a sensible and sustainable market design would be one that supports and enables the clean energy transition. That means increasing reliance on clean energy resources to provide energy, ancillary, and capacity needs; while enabling the orderly retirement of fossil plants.

Applying BSM to policy resources will impede the State's ability to effectively transition away from carbon-emitting supply and toward a 100% clean electricity grid. It will retain existing fossil plants that would otherwise retire and defer the ability to gain operational experience in relying more heavily on clean energy resources, including non-traditional and intermittent clean energy supply.

D. Applying Buyer Side Mitigation to Policy Resources Imposes Uneconomic Excess Costs on Customers and on Society as a Whole

Applying BSM to policy resources would prevent them from clearing the market and, by removing supply, raise prices in the market. This higher price would induce more non-policy-supported resources to clear and thus support more continued investment in maintaining existing plants (and possibly developing new ones) than needed to maintain reliability. That is, the total amount of capacity available and operating would exceed the amount needed to meet the reliability objectives that the capacity market was designed to meet.

This translates into two types of adverse consequences:

- Higher prices would effectuate a wealth transfer from customers to suppliers on the entire volume of capacity transacted in the market, not just the excess resources; and
- Supporting excess capacity results in excess societal costs or deadweight loss that benefits neither customers nor suppliers (who bear the costs of maintaining the uneconomic excess supply).

The scale of these problems would grow with the scope of BSM application and will grow over time as the State proceeds toward achieving its 100% by 2040 clean electricity mandate.

D.1. Expanded BSM Would Cost Customers Approximately $1,780 Million per Year by 2030

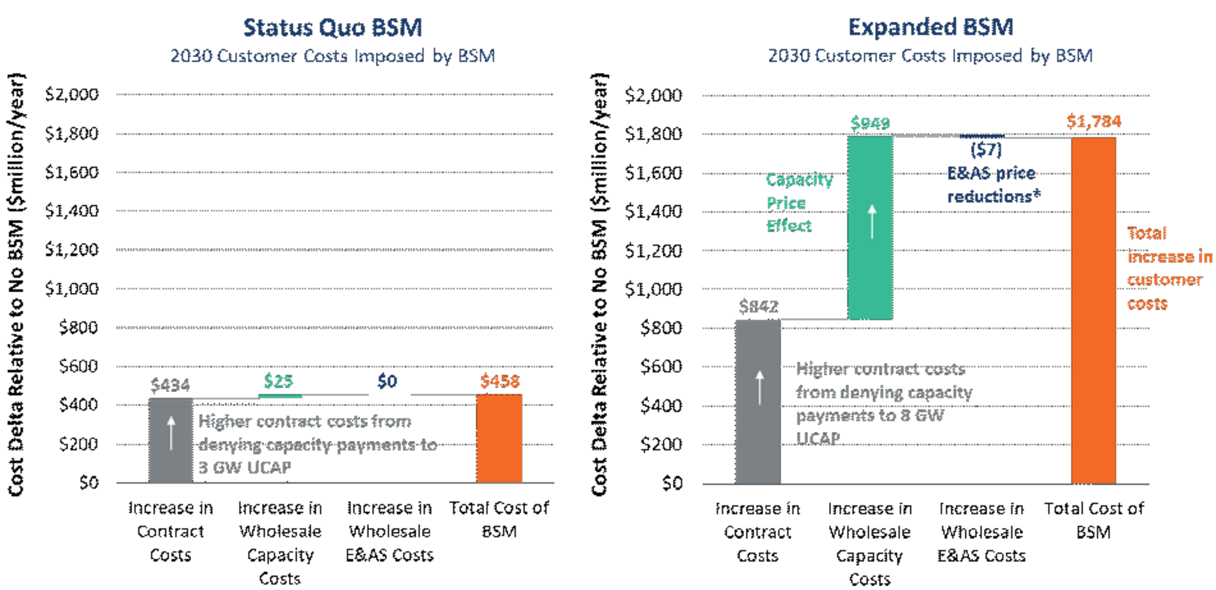
Imposing BSM on policy resources would impose a significant cost on New York customers. We calculated the extent of this cost for several alternative cases with Status Quo and Expanded BSM rules. The detailed assumptions and results from this analysis are included in Exhibit B. These excess costs appear in two ways: (1) as an increase in capacity prices affecting all transactions; and (2) as an increase in contract payments to policy resources because they are deprived of capacity market revenues that go instead to unnecessary substitute resources.

As summarized in Figure 5 below, we estimate costs as an increase in contract payments, plus an increase in capacity market payments, minus a small offset due to reduced energy and ancillary service (E&AS) prices. We estimate that:

- Under the Status Quo BSM rules, costs imposed on customers are currently low but will grow rapidly with the increase in policy resources, with a total cost rising to approximately $460 million per year by 2030. We estimate a relatively modest price impact over the long term, primarily due to the offsetting impact of supply elasticity that could keep prices consistent with the costs of retaining aging fossil plants over the long term.
- An Expanded BSM would have a much more immediate effect due primarily to the application of BSM to approximately 3,100 UCAP MW of nuclear plants that earn ZECs. The customer cost of the Expanded BSM would grow over time to approximately $1,780 million per year by 2030 as the quantity of resources subject to BSM grows. Of this total customer cost, approximately $950 million is caused by higher capacity prices, $840 million is caused by higher contract payments, and approximately $10 million is offset by somewhat lower energy and ancillary service prices.

Our cost estimates account for the offsetting effects of supply elasticity that could reduce price impacts from BSM over the long term. This price mitigation would occur to the extent that excluding policy resources could cause the retention of an almost equivalent amount of replacement capacity and thus results in relatively small net price impact. (Absent supply elasticity, BSM would cause the market to clear at a much higher price along the capacity demand curve and result in much higher customer costs.) We also account for offsetting effects of reductions in the prices of energy and ancillary services due to the excess capacity on the system.

FIGURE 5: CUSTOMER COSTS FROM IMPOSING BSM ON POLICY RESOURCES BY 2030



Sources and Notes: Costs reported in 2030$. *See* p. 7, Exhibit B.

Like any forward-looking estimate of costs, ours are subject to some uncertainty and would differ with alternative assumptions, but we view the overall magnitude to be robust and likely, conservative. Under alternative assumptions, we estimate that Status Quo BSM could cost $400 to $850 million per year by 2030; while expanded BSM could cost $1,300 to $2,750 million per year by 2030.

The robustness of our analysis is further supported by the findings of an entirely independent analysis of the same question that was previously conducted by NorthBridge Group on behalf of

Exelon. In that separate analysis, NorthBridge estimated customer costs of Status Quo BSM would begin at zero in 2021 and rise to $950 million per year by 2025, and that customer costs from an Expanded MOPR would range over $1,200 million to $1,650 million per year over 2021 to 2025.[38] Though the assumptions, methodology, and study years in this Northbridge study differ significantly from our own, the results are relatively consistent. The customer costs of BSM are very high.

D.2. Expanded BSM Would Induce Economic Inefficiencies of Approximately $790 Million per Year by 2030

BSM's costs to customers do not only reflect a wealth transfer to suppliers. The costs also reflect the fact that BSM induces economic waste by inducing capacity owners to make investments to attract or retain capacity resources that are not needed. As we estimated in our analysis, the vast majority of these investments are associated with retaining existing fossil plants that require substantial ongoing investments to stay in operation. For example, the gas-fired steam turbines require significant ongoing reinvestments each year to keep them in operation. In total, keeping an excess 3,050 UCAP MW of these resources online induces excess societal costs on the order of $450 million per year by 2030 under the Status Quo BSM.[39]

With an Expanded BSM, the economic waste is greater, growing to about $790 million per year by 2030.[40] This cost is driven by the same effect of inducing investments to retain resources that are not needed for resource adequacy, though the effect is greater given the larger 7,025 UCAP MW scale of the uneconomic resources.

D.3. Expanded BSM Would Impose Harms to Customers that Significantly Exceed the Benefits to Capacity Sellers

Incumbent capacity sellers are the primary beneficiaries of BSM. However, the approximately $10 million per year in net benefits that these incumbent players would enjoy from Status Quo BSM are far below the $460 million per year increases in costs imposed on customers. In

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38 Aaron T. Patterson, "Impact of Carbon Pricing on Potential Expanded Buyer-Side Mitigation in the NYISO Markets," The NorthBridge Group, at pp. 6–7, November, 2019.

39 This calculation of $451 million per year in excess resource costs is based on the observation on p. 14 of Exhibit B that approximately 3,050 UCAP MW of Gas ST is retained under status quo BSM in the summer and winter capacity auctions that would economically retire with no BSM. We assume that the entirety of this retained capacity is in Zone J. The average capacity market price in Zone J is unchanged between the cases with status quo BSM and no BSM, indicating that Gas ST is the marginal resource; hence the clearing price corresponds with the going-forward cost of these resources.

40 This calculation of $793 million per year in excess resource costs is based on the finding shown on p. 14 of Exhibit B that an average of 7,025 UCAP MW of supply is uneconomically retained between the summer and winter capacity auctions in the case with expanded BSM relative to the case with no BSM. We have assumed that 3,050 UCAP MW of Gas ST is retained in Zone J, as in the case with Status Quo BSM; we have further assumed that all the mitigated capacity that does not clear in the summer in Zone K with expanded BSM is replaced by incumbent supply that is uneconomically retained and that the remaining retained supply is upstate (Zones A-F). Uncleared mitigated capacity in Zone K is estimated as 480 UCAP MW of mitigated storage plus about 186 UCAP MW of mitigated offshore wind, based on the total uncleared quantity of offshore wind in the summer (approximately 900 UCAP MW) times the ratio of mitigated offshore wind in Zone K to total mitigated offshore wind. The average going-forward costs of the retained supply in each zone are estimated as the average of the clearing price with no BSM and the clearing price with Expanded BSM.

Expanded BSM, the benefits to incumbent players are larger at around $1,000 million per year, but still far below the $1,780 million per year in costs to customers.

The reason for this discrepancy is associated with the economic waste induced by BSM as outlined in the following table. As discussed above, customer costs are increased according to the quantity effect (higher contract payments) and price effect (higher capacity market costs). The higher contract payments are earned by policy resources, making up for lost revenues from the capacity market (resulting in overall no net cost or benefit to policy resources that are subject to BSM).

Other incumbent capacity sellers enjoy significant increases in capacity revenue as driven by higher capacity prices and by gaining a greater market share. This causes approximately $460 and $1,790 million per year in increased capacity revenues to incumbent capacity sellers in the Status Quo and Expanded BSM cases, respectively, by 2030. This increase in revenues, however, is offset in large part by a large increase in costs that are incurred to keep uneconomic resources online. Thus, the net benefits to capacity sellers is much lower at approximately $10 or $1,000 million per year in the Status Quo and Expanded BSM cases, respectively.

Overall, the net benefits to incumbent capacity sellers from BSM are significantly lower than the net costs to customers. This is because a portion of the customer costs from BSM fund a wealth transfer from customers to capacity sellers (benefitting fossil generators at the expense of customers), while the remainder of customer cost increases are used to fund uneconomic investments to maintain aging fossil plants that would otherwise retire (benefitting neither customers nor generators).

TABLE 1: APPLYING BSM TO POLICY RESOURCES PRODUCES NET BENEFITS TO INCUMBENT CAPACITY SELLERS AND NET COSTS TO CONSUMERS

		Change from No BSM	
		Status Quo BSM 2030 $ millions Per Year	**Expanded BSM** 2030 $ millions Per Year
Customer Costs			
Increased Capacity Market Costs	[1]	$25	$949
Increased Contract Payments	[2]	$434	$842
Total Customer Cost Increase	[3]	**$458**	**$1,784**
Revenues Earned by Policy Resources			
Decrease in Capacity Payments	[4]	$434	$842
Increase in Contract Payments	[5]	$434	$842
Net Benefits to Policy Resources	[6]	**$0**	**$0**
Revenues and Costs Earned by Other Resources			
Increase in Capacity Revenues	[7]	$459	$1,791
Increase in Investment and Fixed Costs	[8]	$451	$793
Net Benefits to Capacity Sellers	[9]	**$8**	**$998**

Sources and Notes:

[1] – [3]: From Exhibit B, p 15. Note that [3] is slightly less than the sum of [1] and [2] due to small offsets in customer costs due to lower energy and ancillary service prices.

[4] – [6]: Increase in policy resources' contract payments is equal to the decrease in capacity revenues earned by policy resources, given that contract payments are structured to capacity market payments thus keeping policy resources whole with or without BSM. Increase in contract costs in [4] can be found on p. 15 of Exhibit B.

[7]: Increase in capacity payments to non-policy resources is equal to the decrease in capacity payments to policy resources that are excluded from the capacity market (item [4]) plus the total increase in capacity market costs (item [1]).

[8]: Estimated based on Exhibit B, at 12, 14-15, as explained in footnotes 39 and 40.

[9]: Calculated as the increase in capacity revenues to non-policy resources (item [7]) minus the increase in investment and fixed costs of non-policy resources (item [8]).

E. To Continue Offering Broad Benefits to Consumers, Competitive Markets Must Align with and Support Environmental Policy Goals

Competitive wholesale electricity markets, including the NYISO capacity market, have a long history of offering significant benefits to consumers by maintaining reliability at low costs. To continue offering these benefits in the future, the markets will increasingly need to adapt to facilitate and accommodate States' clean energy mandates.

E.1. Expansion of BSM Threatens to Undermine the Future of Competitive Wholesale Electricity Markets

Far from "protecting" capacity markets from the threat of price suppression and policy resources, the application of BSM to policy resources threatens to undermine the benefits and eventually the very existence of competitive capacity markets. The application of BSM to state policy resources erodes the benefits that a competitive capacity market can offer. It imposes unnecessary excess costs on customers and society, interferes with the ability to achieve State policy goals, and effects a wealth transfer from customers to incumbent capacity sellers. These adverse economic outcomes are amplified in any region with a significant environmental policy and will rise quickly as New York proceeds toward achieving its 100% clean energy mandate.

Eventually, the scope and scale of an Expanded BSM would become so great that it would exclude the large majority of all resources from participating. At the same time, the capacity market would continue to produce the high prices that would be necessary to retain excess fossil plants consistent with a fictional scenario as though the State's 100% clean electricity policy did not exist. This outcome is nonsensical and unsustainable. Rather than force customers to endure persistent, growing, and unnecessary excess costs, state policymakers would be forced to exit the capacity market entirely. In fact, state policymakers in New York have initiated a proceeding on the future of resource adequacy in the state for this very reason.[41]

The solution to this problem is simple: eliminate the application of BSM on policy resources and allow prices to reflect the intersection of supply with demand.

E.2. Wholesale Electricity Markets Should Offer States and Customers Competitive Solutions for Aligning with and Achieving Environmental Policy Goals

More generally, well-designed competitive markets will greatly aid the cost-effective, reliable transition to a clean electricity grid. To preserve and expand the role of competitive markets in offering broad consumer benefits, they will increasingly need to align with and support states' environmental goals. The FERC has already acknowledged the benefits of supporting state goals through the reflection of enhanced carbon pricing within wholesale electricity markets.[42] States, ISOs, and stakeholders will increasingly identify opportunities to enhance the markets for a decarbonized grid, such as through enhanced carbon pricing, enhanced energy and ancillary service market designs, and solutions for aligning the capacity market with state policy.[43] These reforms may take some time but will ultimately support the evolution of toward a fit-for-purpose wholesale market for the decarbonized grid.

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[41] *See*: NYPSC, Case Number 19-E-0530, "Proceeding on Motion of the Commission to Consider Resource Adequacy Matters."

[42] FERC, Docket No. AD20-14-000, "Carbon Pricing in Organized Wholesale Electricity Markets," October 15, 2020.

[43] *See* Samuel A. Newell, Roger Lueken, Jürgen Weiss, Kathleen Spees, Pearl Donohoo-Vallet, Tony Lee, The Brattle Group, "Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals," August 10, 2017; Kathleen Spees, Samuel A. Newell, Walter Graf, Emily Shorin, "How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals: Through a Forward Market For Clean Energy Attributes Expanded Report Including A Detailed Market design Proposal," September 2019; and New York Independent System Operator (NYISO), "Reliability and Market Considerations For A Grid in Transition," December 20, 2019.

F. Certification

We hereby certify that we have read the filing signed and know its contents are true as stated to the best of our knowledge and belief. We possess full power and authority to sign this filing.

Respectfully Submitted,

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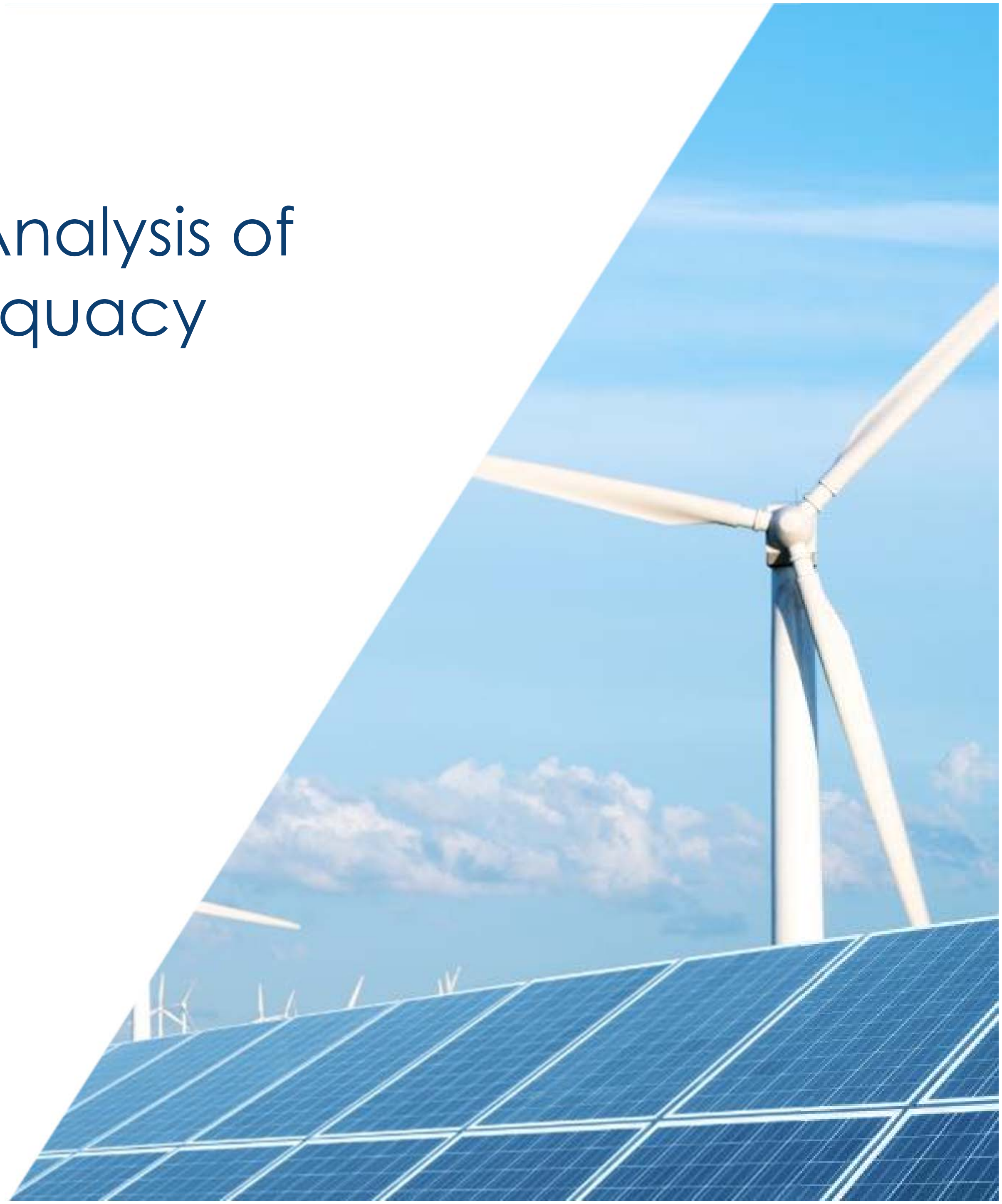
November 18, 2020

EXHIBIT B

Spees, *et al.*, "Quantitative Analysis of Resource Adequacy Structures," Prepared for NYSERDA and NYSDPS, July 1, 2020

Quantitative Analysis of Resource Adequacy Structures



PREPARED FOR
NYSERDA and NYSDPS

PREPARED BY
Kathleen Spees
Sam Newell
John Imon Pedtke
Mark Tracy

July 1, 2020

THE Brattle GROUP

Study Scope

NYSERDA and NYDPS retained Brattle to evaluate several alternative resource adequacy constructs that differ primarily in who administers them and how Buyer-Side Mitigation (BSM) is applied; this deck presents estimates of the differences in customer costs.

Summary of RA Structures Corresponding to Brattle Qualitative Analysis Memo

Structure		Description	Cost Evaluation
1	**ICAP Market with Status Quo BSM**	Current ICAP market with current rules	Compared to #3 to indicate costs of Status Quo BSM
2	**ICAP Market with Expanded BSM**	Same as above but with potential expansion to BSM rules corresponding to FERC's December 2019 order for PJM	Compared to #3 to indicate costs of potential Expanded BSM
3	**Centralized Market for Resource Adequacy Credits (RACs), without BSM**	Functionally similar to current ICAP market, but with rule-setting by State No BSM, except as applied by PSC to prevent the intentional introduction of uneconomic capacity to profitably suppress capacity prices	Evaluated as "No BSM"
4	**LSE Contracting for RACs**	Same as #3, but with no centralized market LSEs must procure sufficient RACs bilaterally	Similar to #3 but difficult to quantify
5	**Co-optimized Capacity and Clean Energy Procurement**	Same as #3, but a State entity would procure RACs and RECs for LSEs in a joint, co-optimized auction	Not evaluated (out of scope)

Approach and Key Assumptions

To estimate customer cost impacts, we simulated future wholesale markets (including the application of BSM) in 2030, using Brattle's GridSIM model. Key Assumptions:

- Modeled fleet reflects the **Climate Leadership and Community Protection Act** (CLCPA) and **NYISO CARIS study**:
  - 70% of load is met by renewable resources by 2030 (does not include Nuclear generation)
  - Annual gross load, 6,100 MW of offshore wind (OSW), 3,000 MW of storage, and 7,500 MW of behind-the-meter (BTM) solar assumptions consistent with CLCPA targets and 2019 CARIS study assumptions
- Assumptions on BSM applicability were updated to align with NYISO's proposed exemption rule:
  - 1. "Status Quo" applies BSM to new renewables and storage in Zones G-J, except approximately 550 UCAP MW of policy exemptions
  - 2. "Expanded BSM" extends BSM to all zones, incl. nuclear and half of the existing hydro resources (assuming CapEx projects), with exemptions for 160 UCAP MW of OSW in Zone J, 173 UCAP MW of OSW in Zone K, and 41 UCAP MW of PV in Zones G-I
  - 3. Centralized RAC Market w/ "No BSM" does not exclude any resources from the capacity market
- Assumptions on UCAP ratings of intermittent resources affect the magnitude of BSM
  - UCAP value declines with penetration; analyzed output vs. net load to estimate effective load-carrying capability (ELCC)
  - Available output data had low CF% and output diversity, making impact estimates conservative; on the other hand, analysis does not recognize that transmission constraints could make the local J/K value fall faster with penetration
- Other key assumptions: resources' fixed and variable costs contributing to capacity prices via supply elasticity
- Sensitivity analyses: explored effects of nuclear retirements; higher load; quantity of BSM policy exemptions

The 2030 system examined here leveraged CARIS 70*30 and otherwise made necessary simplifying assumptions. While the system examined in 2030 does not represent a prediction of the future system, it is a reasonable expectation for the purpose of examining alternative RA structures

Cost estimates are thus indicative; impact will ultimately depend on the year, load, supply mix, UCAP ratings, and capacity supply elasticity, and the details of any changes to BSM rules

Updates to this Quantitative Analysis

We have updated this quantitative analysis based on stakeholder input received and to better reflect NYISO's proposed BSM rules and recent developments

- The most important changes provide a more accurate representation of likely outcomes under the "Status Quo" buyer-side mitigation approach, including:
  - Higher renewables exemption (assuming that NYISO's April 20 filing is accepted)
  - Sensitivity analysis on the quantity of public policy resource exemptions
  - Offer floor at the minimum of 0.75x mitigation Net CONE or resource offer floor
  - Updated representation of resource retirements and winter only status as per the NY DEC "Peaker Rule" Part 227-3 and 2020 Gold Book
  - Updated going-forward cost assumptions for fossil resources that are at risk of retirement (identified as a key study sensitivity)
- **Overall Impact of Updates:** Estimated customer costs imposed by Status Quo BSM are somewhat lower, but the uncertainty range remains similar at approximately $0.4-$0.9 billion per year; Expanded BSM scenario costs remain similar at approximately $1.3-$2.8 billion per year

Summary of Conclusions

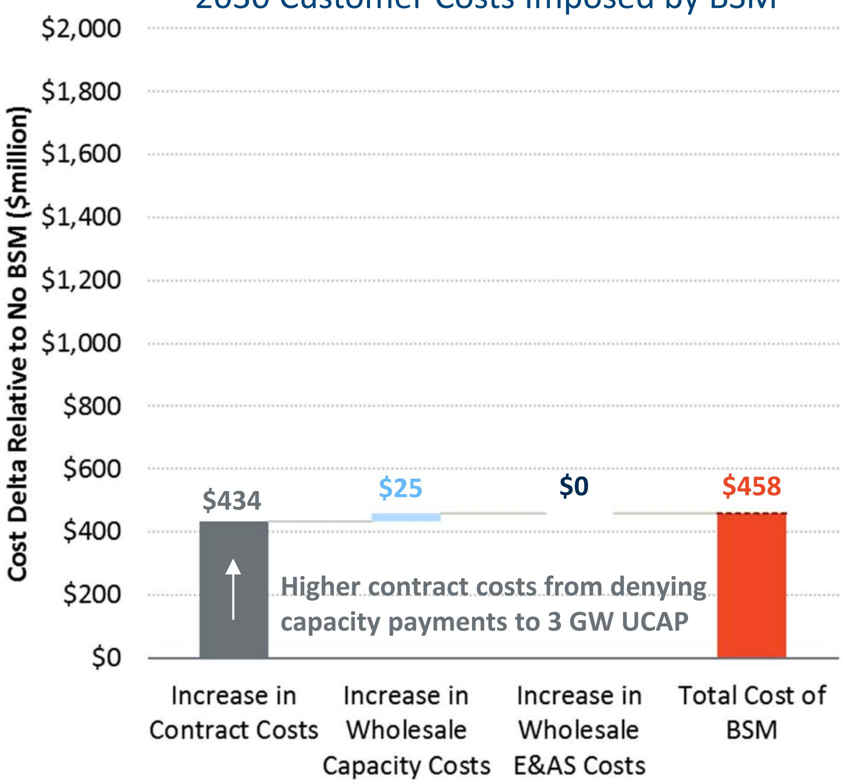
- By 2030 relative to a No-BSM scenario, estimated customer costs increase by:
  - **$0.4-0.9 billion/year** under Status Quo BSM (~12%-20% of statewide capacity costs or ~24%-34% of Zones G-J capacity costs), range depending on load growth and exemptions
  - **$1.3-2.8 billion/year** under Expanded BSM (~35%-63% of statewide capacity costs), range depending on load growth and nuclear resource retention
- This reflects costs of over-procuring capacity because mitigated policy resources would not be accounted for in the capacity market, including:
  - Contract costs increase for policy resources, since they are denied capacity payments
  - Capacity market clearing prices rise
- These estimates account for moderating long-term factors:
  - Long-term supply elasticity mitigates capacity price impacts so it is smaller than the "double-payment" quantity effect (showing up as higher contract costs)
  - Lower resource UCAP values at higher penetration of mitigated renewable resources limit the impact of BSM
  - Offsetting E&AS impacts, but these are relatively small
  - Policy resource exemptions can somewhat mitigate costs

Analytical Results

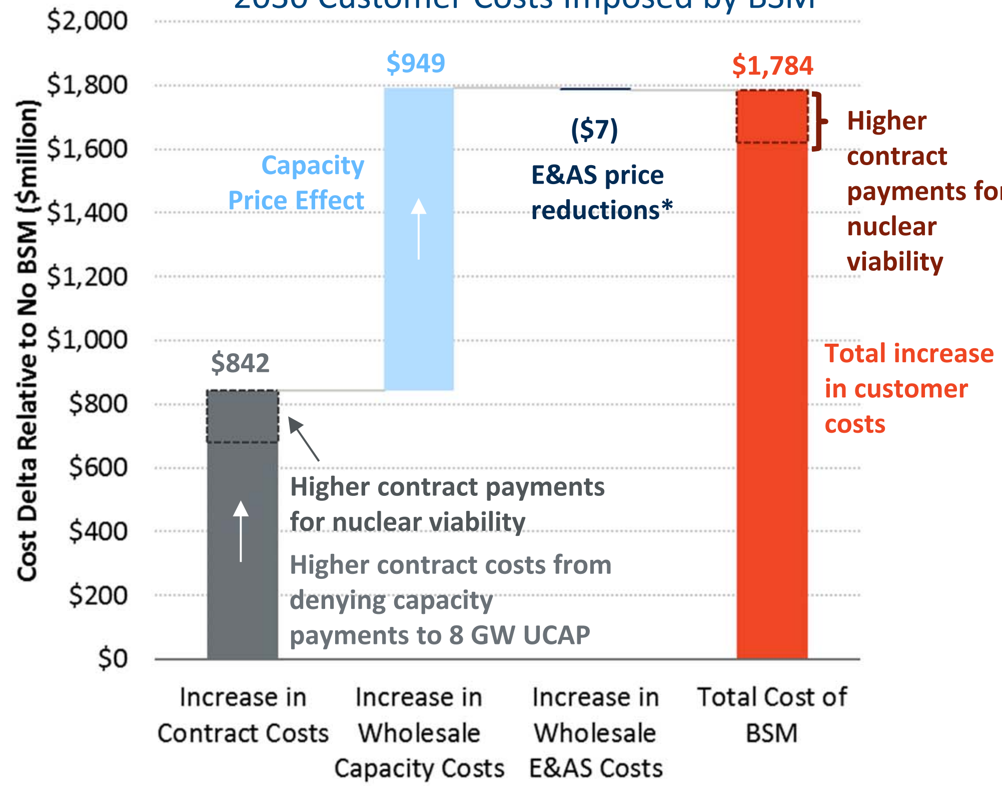
Estimated Customer Costs of BSM in 2030

Net impact of BSM on customers is $0.5 billion/yr under Status Quo; $1.8 billion/yr under Expanded BSM.

Status Quo BSM (#1 vs. #3)



Expanded BSM (#2 vs. #3)

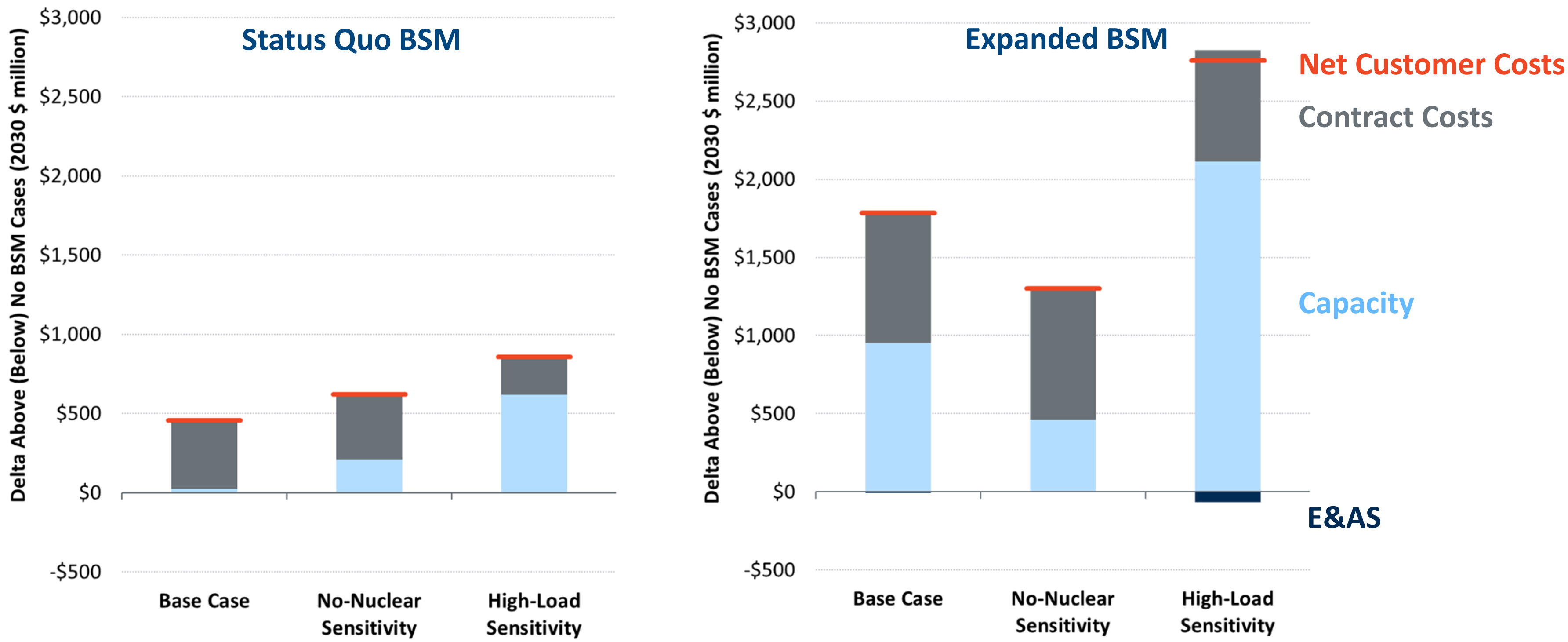


* Energy and AS prices decrease in some cases because excess capacity depresses prices in tight hours; and because higher contract payments (due to lack of capacity payments) cause energy prices to be more negative in over-generation hours.

Sensitivity of BSM Costs to Supply-Demand Balance

Customer costs of BSM are sensitive to peak load (higher load driving higher costs)

Increased Annual Customer Costs Relative to No-BSM Structure



Notes: "**No-Nuclear Sensitivity**" loses all >3 GW of upstate nuclear, largely replaced by retaining gas CCs, so fewer resources to mitigate.
"**High-Load Sensitivity**" results in additions of onshore wind to meet 70% target.

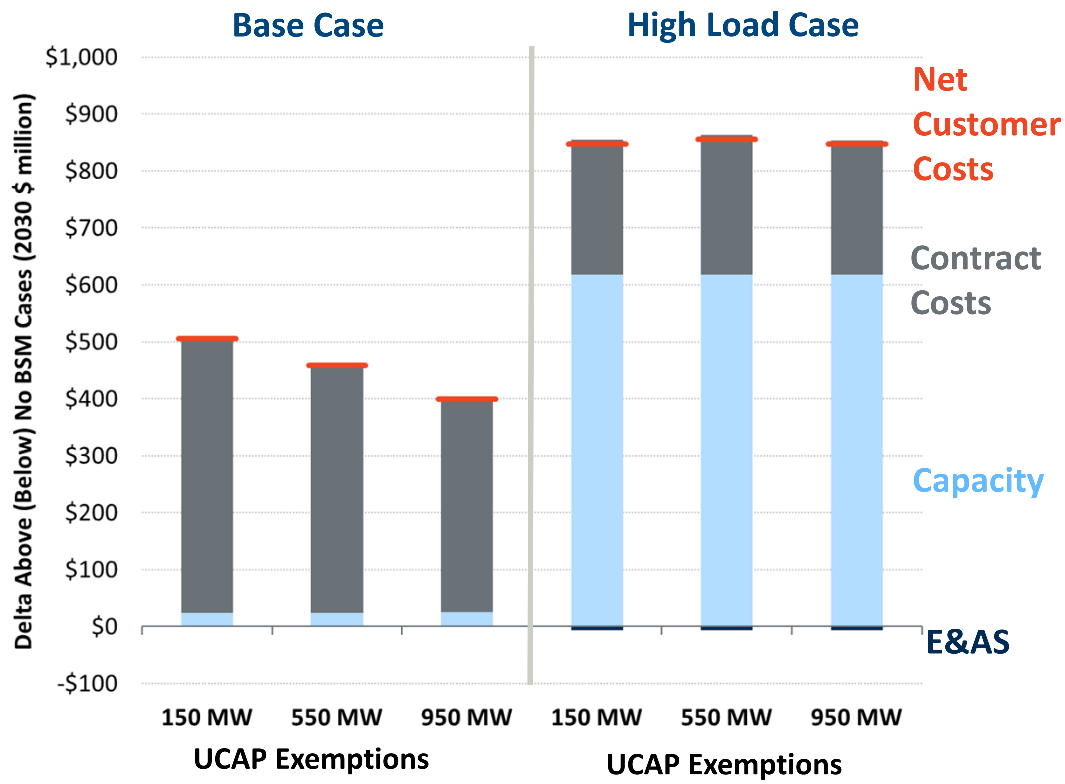
Sensitivity of Status Quo BSM Costs to Policy Resource Exemptions

We evaluated the sensitivity of Status Quo costs to +/- 400 MW of policy resource exemptions

Costs remain similar because:

- **Base Case:** Gas ST is marginal, so 400 MW policy exemptions displaces 400 MW of gas ST retention
- **High Load Case:** Generic offer floor is marginal in all cases, so 400 MW exemptions results in +400 MW generic offer floor resources (and vice versa)

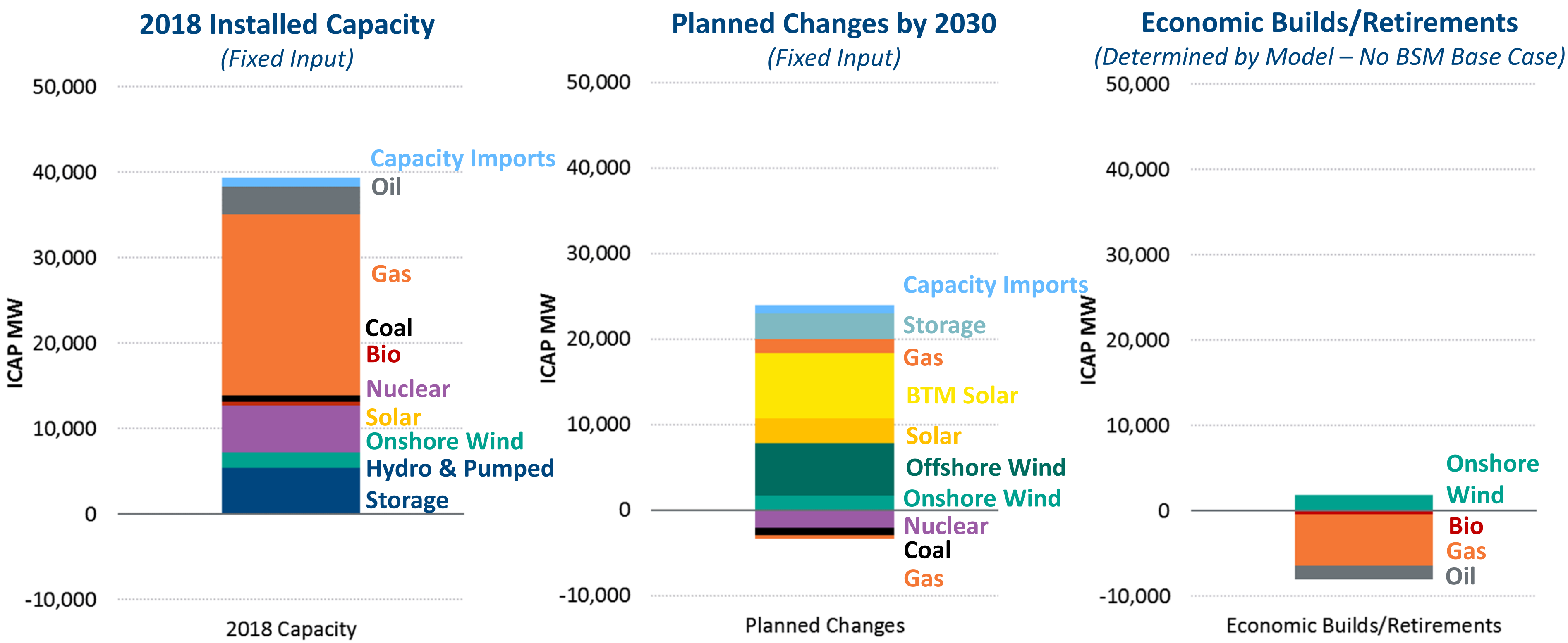
Status Quo BSM Costs



Base Case Detailed Results

Base Case Supply Mix

Existing generation is consistent with the 2019 Gold Book, and planned capacity changes are based on signed CES contracts and CARIS study assumptions. The model economically retires old plants and builds new clean ones to meet any remaining gap to reach CLCPA 70% target



Note: Model determines if 2018 existing supply resources will retire by 2030.

Note: Model determines economic resource builds needed to reach CLCPA targets (incremental to planned changes).

Capacity Subject to Mitigation
before considering exemptions or clearing

Mitigated Non-Emitting Capacity by Zone (ICAP MW)

Blue shading subject to Status Quo BSM

Expanded BSM applies to blue and teal

	2018 Capacity	Planned/Assumed 2019-2030 Additions/Retirements (Fixed Input)					Economic Additions (Determined by Model)		Total Capacity by 2030
		Zone A-E	Zone F	Zone G-I	Zone J	Zone K	Zone A-E	Zone F-K	
Hydro & PS	5,436	0	0	0	0	0	0	0	5,436 **
Onshore Wind	1,739	1,710	0	0	0	0	1,814	0	5,263
Offshore Wind	0	0	0	0	4,320*	1,778	0	0	6,098
Solar	77	2,677	0	284*	0	0	0	0	3,038
Storage	0	660	240	270	1,350	480	0	0	3,000
Nuclear	5,399	0	0	(2,054)	0	0	0	0	3,345
Capacity Import	1,100	0	0	0	1,000	0	0	0	2,100
Total	**13,751**	**5,047**	**240**	**(1,500)**	**6,670**	**2,258**	**1,814**	**0**	**28,280**

Notes: 2018 installed capacity informed by 2019 Gold Book. Planned/assumed builds are informed by 2019 CARIS study assumptions and signed CES contracts based on 2018-2019 CES contract summary document and recent 2019 Tier 1 solicitation.

* 816 ICAP MW OSW in Zone J and 880 ICAP MW OSW in Zone K procured in 2018 solicitation and 284 MW solar in Zone GHI exempt in both Status Quo and Expanded BSM. See the following slide for assumptions regarding status quo renewable exemptions as assumed consistent with the April 20 NYISO filing.

** Half of existing hydro fleet assumed to be mitigated under Expanded BSM.

Status Quo Exemptions

The quantity of possible public policy resource exemptions under the NYISO's April 20 proposed approach is subject to considerable uncertainty. Our updated analysis assumes ~550 UCAP MW of exemptions (with a sensitivity analysis of +/-400 UCAP MW)

- Given the large uncertainties, our assumed quantity of exemptions is intentionally abstracted from specific predictions such as which resources may be deemed "policy-driven" retirements
- Overall quantity is consistent with outlook for load growth, retirements, and demand curve width
- In "high exemptions" scenario, we further assume that some storage becomes exempt through other means (such as via Part A or Part B tests)

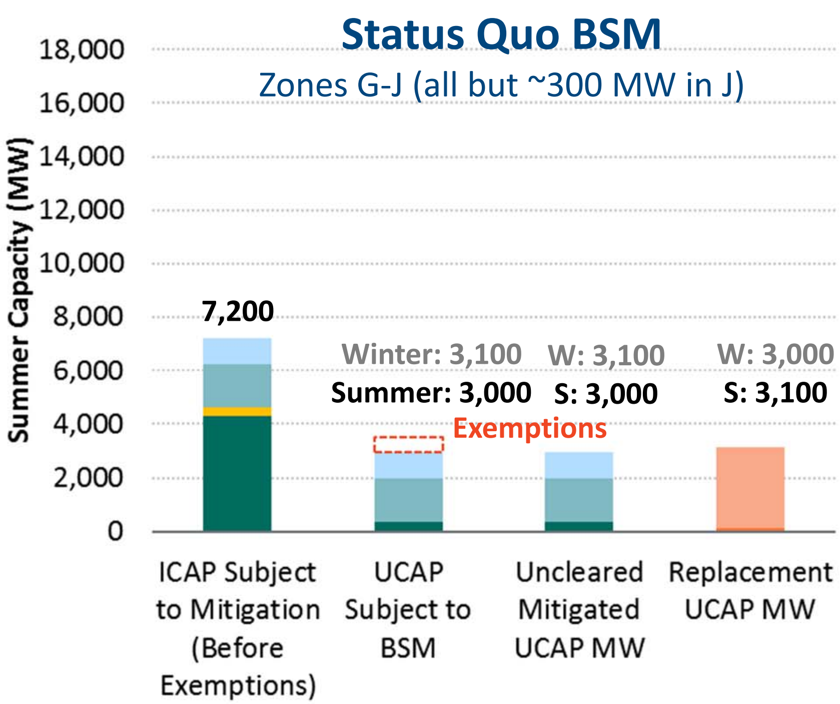
Status Quo Exemptions by Zone

	Zones G-I	Zone J	Zones G-J
Summer UCAP Supply (UCAP MW)			
Offshore Wind	0	848	848
Storage	270	1,350	1,620
Solar	41	0	41
Capacity Imports	0	1,000	1,000
Exemptions (UCAP MW)			
Public Policy Resources	41	507	548
Remaining Mitigated Resources (UCAP MW)			
Offshore Wind	0	341	341
Storage	270	1,350	1,620
Solar	0	0	0
Capacity Imports	0	1,000	1,000

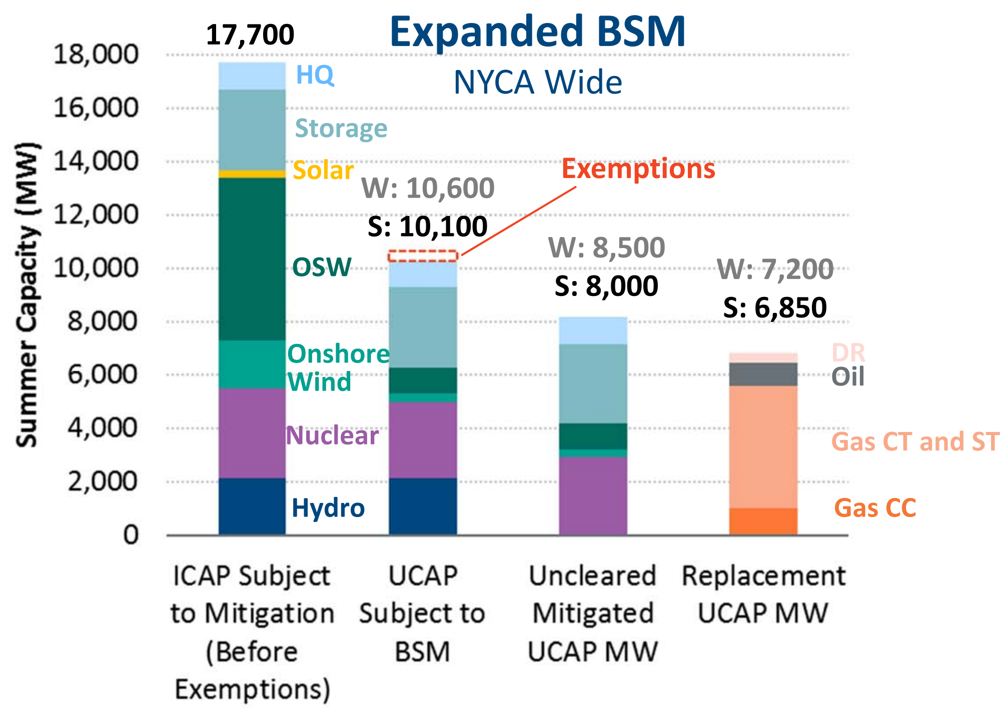
Summary of Mitigation and Market Response Quantities (NYCA-Wide)

In Status Quo BSM, essentially all of the ~3,000 summer UCAP MW uncleared mitigated capacity is replaced by retained gas ST

In Expanded BSM, ~1,150 summer UCAP MW of the 8,000 summer UCAP MW uncleared mitigated capacity is *not* replaced (mostly Upstate), resulting in a higher capacity prices and costs



Mitigated capacity in Zones G-J only under Status Quo, mostly OSW and storage in Zone J that is replaced by retained gas ST plants. UCAP values reflect average ELCC. Capacity numbers are approximate.



Mitigated capacity in all zones. Mitigated OSW and storage in Zones J and K largely offset by retained gas resources. All UCAP values shown reflect average ELCC. Capacity numbers are approximate.

Prices and Customer Costs

Zone J Capacity prices remain similar across all structures as retiring gas ST resources are marginal. Capacity prices in A-F increase significantly in Expanded BSM as more renewables and nuclear resources are mitigated, thus retaining more thermal plants that would otherwise retire

Wholesale Market Prices

Zone	Capacity Market Prices (2030 $/kW-month) 1. Status Quo	2. Expanded BSM	3. No BSM	Delta Above (Below) No BSM (2030 $/kW-month) 1. Status Quo	2. Expanded BSM
A-E	$3.65	$8.13	$3.69	($0.04)	$4.44
F	$3.65	$8.13	$3.69	($0.04)	$4.44
G-I	$6.05	$8.13	$6.05	($0.00)	$2.08
J (NYC)	$12.33	$12.32	$12.34	($0.01)	($0.02)
K (LI)	$13.05	$13.88	$13.05	$0.00	$0.83

Zone	Energy Market Prices (2030 $/MWh) 1. Status Quo	2. Expanded BSM	3. No BSM	Delta Above (Below) No BSM (2030 $/MWh) 1. Status Quo	2. Expanded BSM
A-E	$28.02	$27.99	$28.02	$0.00	($0.03)
F	$30.28	$30.23	$30.28	$0.00	($0.05)
G-I	$30.36	$30.33	$30.36	$0.00	($0.03)
J (NYC)	$30.36	$30.33	$30.36	$0.00	($0.03)
K (LI)	$32.19	$32.19	$32.19	$0.00	($0.00)

Cost of BSM

Category	Customer Costs Delta Above (Below) No BSM (2030 $ million) 1. Status Quo	2. Expanded BSM
Wholesale Market Cost	**$25**	**$941**
Energy	$0	($7)
Ancillary Services	$0	($0)
Capacity	$25	$949
Contract Costs	**$434**	**$842**
Total Customer Cost	**$458**	**$1,784**
Excluding Nuclear Make-Whole	$457	$1,622

Modeling Approach and Assumptions

Brattle GridSIM Model

Inputs

Supply

Existing resources
Fuel prices
Investment/fixed costs
Variable costs

Demand

Representative day hourly demand
Capacity needs

Transmission

Zonal limits
Intertie limits

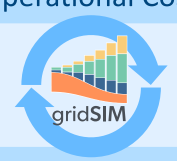
Regulations, Policies, Market Design

Capacity market
Carbon pricing
Procurement mandates

GridSIM Optimization Engine

Objective Function

Minimize NPV of Investment & Operational Costs



Constraints

- Market Design and Co-Optimized Operations
  - *Capacity*
  - *Energy*
  - *Ancillary Services*
- Regulatory & Policy Constraints
- Resource Operational Constraints
- Transmission Constraints

Outputs

Annual Investments and Retirements

Hourly Operations

System and Customer Costs

Supplier Revenues

Emissions and Clean Energy Additions

Market Prices

Demand Assumptions

- "Base Load" load assumptions align with 2019 CARIS study input assumptions for 2030
- "Base Load" assumes lower demand than 2019 (156 TWh gross load)
- Modeled "High Load" based on State Team input that assumes greater load than 2019

2030 Demand Assumptions

	Base Load	High Load
Scenarios	Base Case No-Nuclear	High-Load
Annual Gross Load	145 TWh	169 TWh
Gross Peak Load	30 GW	35 GW
Net Peak Load	28 GW	33 GW

Sources and Notes:

"Base Load" annual gross load assumptions are based on 2019 CARIS study. Used ratio of 2019 annual gross load and CARIS annual gross load to convert 2019 gross peak loads to 2030 gross peak loads on zonal level.

"High Load" annual gross load assumptions based on State Team's input. Calculated peak loads based on annual gross load ratio as described above.

Netted out assumed 7,542 MW of solar BTM (based on 2019 CARIS study) valued at ~27% summer capacity value from gross peak load to calculate net peak load (similar to Gold Book assumptions).

2019 load data taken from NYISO OASIS data.

Supply Cost Characteristics

- **Resources' fixed O&M costs** affect supply elasticity and BSM price impacts. Sources:
  - *New Gas CCs, CTs*: 2020 costs from Demand Curve Reset (DCR); 2.2% cost inflation rate
  - *New Gas STs*: 2019 costs and cost decline rate from 2019 NREL ATB (0% to -1%/year real)
  - *New wind, solar, storage*: 2019 costs and cost decline rate from 2019 NREL ATB (0% to -7% /year real)
  - *Existing Nuclear*: 2019 costs from NEI (constant real), plus assumed $280/kW-year refurbishment cost adder in 2030
  - *Existing CTs, STs*: FOM from NYISO 2018 SOM Report
  - *Other existing thermal:* FOM assumed 2x new units
  - *All other existing:* Same FOM as new resources
  - *Zone J and K*: FOM assumed 1.3 – 2.7x higher than upstate based on DCR zonal cost ratios
- **Offshore wind** tied to either zone J or K
- **Utility-scale PV and onshore wind** cannot be built in zones J or K

2030 Resource Cost Assumptions

	Upstate New Resource Capital Cost *2030$/kW*	Upstate New Resource FOM *2030$/kW-yr*	Upstate Existing Resource FOM + Refurb Costs *2030$/kW-yr*	Variable O&M *2030$/MWh*
Natural Gas				
Combined cycle	$2,300	$27	$54	$2
Combustion turbine	$1,200	$14	$25	$7
Steam turbine	$5,000	$43	$72	$11
Battery Storage				
4-hour duration	$1,100	$26	$26	$6
Solar PV				
Utility scale	$1,100	$13	$13	$0
Wind				
Offshore (downstate)	$4,600	$107	$107	$0
Onshore	$1,600	$50	$50	$0
Nuclear				
Single-unit	N/A	N/A	$602	$3
Multi-unit	N/A	N/A	$491	$3

Sources and Notes:

Includes interconnection and network upgrade costs. NREL 2019 ATB, NYISO DCR Model 2019-2020 and 2020-2021 , and NEI Nuclear Costs in Context.
VOM for storage resources reflect efficiency losses. Existing FOM for nuclear includes refurbishment costs.
FOM costs for existing STs and CTs were based on average GFC shown in Figure 16 of the 2018 State of the Market Report; FOM costs for existing Gas CTs upstate assumed to be half of those for existing Gas CTs in Zone K.
FOM costs for other existing thermal resources were assumed to be 2x that of comparable new ones, informed by EPA Integrated Planning Model document.
Nuclear refurbishment costs informed by refurbishment costs for nuclear plants in Ontario.

ELCC Modeling Approach

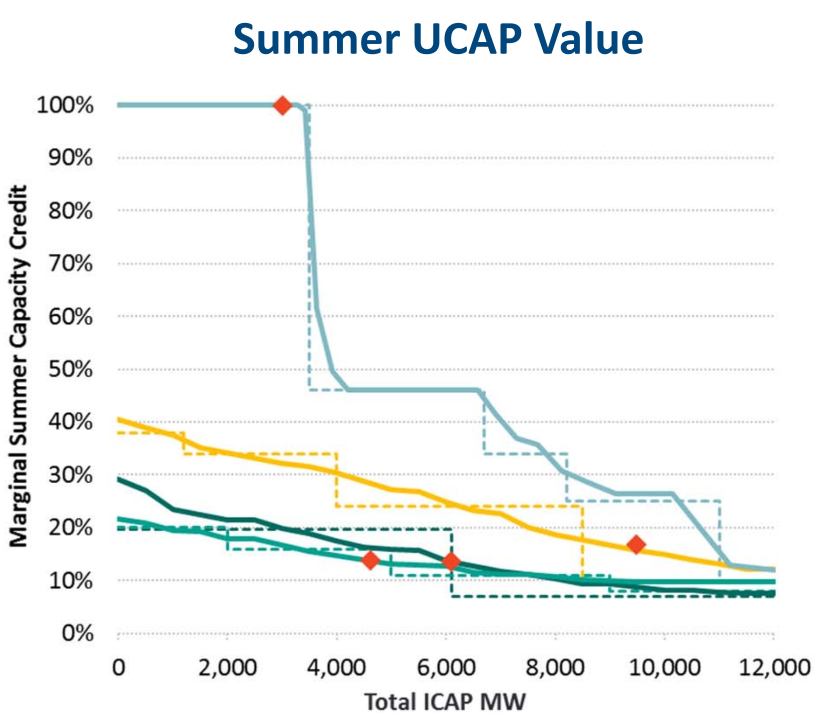
Supply Resource	Concept	Methodology
Wind and Solar Resources	Generation of new wind and solar additions is correlated with previously deployed resources. New resources therefore provide less marginal capacity value than previously added resources.	1. Across 8760 hours, identify 100 top NYCA net load hours 2. Calculate wind UCAP value as avg. output in those hours 3. Repeatedly change the MW of wind installed, all else equal 4. Each time, find top 100 net load hours and the avg. output 5. Repeat process for offshore wind and solar; for each one, hold other variable technologies at likely 2030 levels
Storage Resources	Energy storage can change the "shape" of peak net load periods, flattening and elongating peak periods. As more storage is deployed, longer discharge durations are therefore required to provide the same capacity value.	1. Across 8760 hours, analyze MW of storage required to reduce NYCA net peak load by 1 MW 2. Calculate UCAP value as 1 MW peak reduction / MW storage required 3. Increase amount of storage assumed, holding all else equal. Simulate effect of increased storage on net peak load 4. Repeat steps 1 – 3 across many storage deployment levels 5. Repeat process for storage of different durations

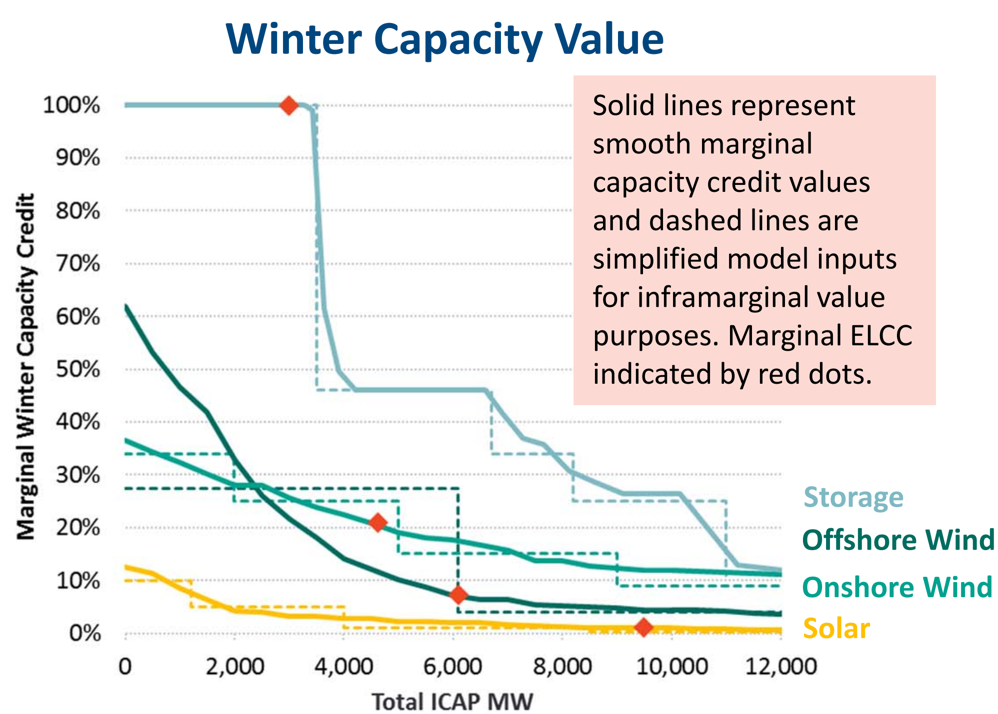
Base Case UCAP Value Curves

modeled based on NYCA-wide net load

As the penetration increases, marginal effective load-carrying capability (ELCC) decreases.

Note: this analysis may have conservatively low ELCCs for renewables, based on hourly data with lower output than future installations are likely to achieve (and that does not capture diversity across sites for OSW); on the other hand, this analysis uses NYCA-wide net load without considering how transmission constraints could reduce value more quickly.





Note: solar capacity credit curves include assumed 7,542 MW of solar BTM already on the grid (based on CARIS study assumption).

Assumptions on BSM Applicability

Resource Type	BSM in Structure 1. Status Quo		BSM in Structure 2. Expanded BSM	
	Zones G-J	Rest of System	Zones G-J	Rest of System
Nuclear	N/A	N/A	N/A	3,345 ICAP MW
OSW	1,740 ICAP MW (assumed 507 UCAP MW exemption in Zone J applies to OSW)		3,504 ICAP MW (assume 816 ICAP MW of already signed contracts exempt)	898 ICAP MW (assume 880 ICAP MW of already signed contracts exempt)
Existing Solar and Onshore Wind	No		No	No
New Utility Scale Solar and Wind	Any new utility scale solar or onshore wind in Zones G-J		All new utility scale solar and onshore wind	
Bulk Storage	1,620 ICAP MW		1,620 ICAP MW	1,380 ICAP MW
Existing Hydro	No		50 ICAP MW	2,085 ICAP MW
Tier 2 Renewables	No		No	No
New HQ Imports	1,000 MW in Zone J		1,000 MW in Zone J	N/A
Demand Response	No		No	No
Fossil Resources	No		No	No

Source: Assumptions on applicability provided by NYSERDA/DPS staff.

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Attachment E

Kathleen Spees, Travis Carless, Walter Graf, Samuel Newell, et al., *Alternative Resource Adequacy Structures for Maryland: Review of the PJM Capacity Market and Options for Enhancing Alignment with Maryland's Clean Electricity Future*, Brattle Group (Mar. 2021)

Alternative Resource Adequacy Structures for Maryland

REVIEW OF THE PJM CAPACITY MARKET AND OPTIONS FOR ENHANCING ALIGNMENT WITH MARYLAND'S CLEAN ELECTRICITY FUTURE

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March 2021

NOTICE

This report was prepared for the Maryland Energy Administration (MEA) on behalf of the Maryland Energy Service (MES), in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants. There are no third-party beneficiaries with respect to this report, and The Brattle Group does not accept any liability to any third party in respect of the contents of this report or any actions taken or decisions made as a consequence of the information set forth herein.

The Maryland Public Service Commission (PSC) further entered into a memorandum of understanding with The Brattle Group for the sole purpose of granting The Brattle Group access, as a Maryland PSC Authorized Person, to confidential data made available by PJM Interconnection. The Brattle Group executed PJM's Schedule 10 Non-Disclosure Agreement (NDA) as an Authorized Person of the Maryland PSC and abided by the terms of the NDA with regard to confidential data utilized in this study. The Brattle Group's access to confidential data acquired by the Maryland PSC from PJM was for the sole purpose of validating assessments related to resource adequacy alternatives in PJM and associated impacts on Maryland ratepayers. The Brattle Group has not shared these data with the MEA, MES, or any other parties.

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Executive Summary

Maryland has for two decades relied on competitive wholesale markets within the PJM Interconnection (PJM) regional transmission organization (RTO) to procure low-cost and reliable power. Maryland customers have benefitted enormously from participation in the broad regional marketplace for electricity, saving on the order of $270-340 million per year from wholesale power market participation.[1] These savings have derived largely from efficient generation dispatch across the large multi-state region, reductions in the quantity of resources needed to maintain reliability, and competition in PJM's markets that spurred innovative technologies such as demand response and low-cost new generation.[2]

Maryland's longstanding policy choice to rely on competitive markets places the risk of uneconomic investments on private investors rather than customers, thus avoiding the possibility of large customer cost inflation from poor resource planning decisions. This reliance on markets means that Maryland policymakers have not exercised direct control over which resources and which resource types would be built. More recently, however, Maryland has mandated a transition to a decarbonized power supply mix. The *2019 Clean Energy Jobs Act* requires 50% renewable power supply by 2030, of which at least 14.5% is to be supplied by in-state solar resources and up to another 1,200 megawatts (MW) from offshore wind, subject to a budget cap. The Act further requires a study of the costs of achieving a 100% clean energy supply mix by 2040.[3] Attracting enough investment in clean energy to meet these goals will require financial support outside of the PJM wholesale power markets, since those markets were designed to achieve low-cost and reliable power supply while remaining indifferent to the underlying resource types. To date, the PJM markets have not been designed to *promote* the meeting of states' environmental objectives.

Over the past few years, a conflict has developed between states' clean energy objectives and Minimum Offer Price Rule (MOPR) provision within PJM's Reliability Pricing Model (RPM) capacity market. Policymakers, renewable advocates, and environmental groups are concerned that the MOPR will impose excess costs on customers in states with increasing clean energy mandates and conflict with policy goals for clean energy. We were asked by the Maryland Energy Administration (MEA) to describe the impacts of the MOPR on Maryland customers and clean energy policies, assess the Fixed Resource Requirement (FRR) and other options that Maryland might pursue to mitigate the costs of MOPR, and conduct an economic analysis comparing the relative merits of available options.

1 Derived from the PJM value proposition estimating $3,200 to $4,000 million per year in regional savings across PJM, and applying the 8.4% load share of Maryland customers from PJM BRA Auction Results Planning Parameters from the 2022/23 Delivery Year.

2 PJM's capacity market has played a key role in lowering costs, producing capacity prices significantly below administrative estimates of the long-run marginal costs of supply. This was partly due to an initial surplus, but even as load growth and retirements increased the need for new supply, the competitive market has attracted and retained a great variety of resources at low prices. See Monitoring Analytics, State of the Market Report for PJM: Volume II, Section 5 – Capacity Market, Table 5-21: Capacity market clearing prices: 2007/08 through 2021/22 RPM Auctions, March 12, 2020.

3 Maryland State Senate, "Clean Energy Jobs" Senate Bill 516, passed on May 25 2019.

THE EXPANSION OF THE MINIMUM OFFER PRICE RULE TO POLICY RESOURCES

The generation portion of Maryland customer electricity bills reflects competitive wholesale market prices, primarily for energy, but also for "capacity", and various smaller components. PJM's capacity market is a centralized competitive auction mechanism for ensuring adequate electricity supply regionally and by location across the PJM footprint. The Base Residual Auction (BRA) is conducted three years prior to delivery and procures enough capacity resources to meet the projected peak demand plus an uncertainty reserve margin. Generation, demand response, and storage resources across PJM offer their qualified capacity at a price. Then the auction selects the lowest-cost resources to take on a capacity supply obligation in exchange for a payment at the auction clearing price. Three years later, in the delivery period, the costs of capacity procurements are allocated to load-serving entities (LSEs) and passed along to customers in proportion to their peak electricity consumption.

The MOPR is a provision of the capacity market rules that was originally intended to prevent market manipulation by entities with a large net-buyer position. Absent MOPR, a large net buyer or state agency on behalf of its constituents could aim to suppress market prices by offering a small amount of uneconomic capacity supply into the market below cost in order to suppress market clearing prices. By taking a loss on that small sell position, net buyers could then benefit from lower prices on their much larger short position in the market. Such manipulative behavior has the potential to erode economic value and undermine private investors' confidence in market price formation. The MOPR was designed to discourage manipulative price suppression by forcing large net buyers to offer at a minimum price equal to the resource's true costs (symmetrical rules are imposed on sellers of capacity in order to prevent them from exercising economic or physical withholding to inflate prices). When applied for its narrow original purpose of preventing market manipulation, MOPR and the symmetrical rules preventing withholding can support effective competition and efficient market outcomes and would have no impact on states' environmental policies.

The conflict with state policy objectives has arisen from a Federal Energy Regulatory Commission (FERC) order in December 2019 that expanded the application of PJM's MOPR.[4] In that order, the FERC approved the repurposing of MOPR to apply much more broadly to all capacity resources that may earn any "out of market" policy support. Under the expanded MOPR, policy-supported resources are required to offer their capacity into RPM at higher prices. A policy resource's MOPR price is set at the levelized going-forward investment and fixed costs, minus anticipated energy and ancillary service revenues. Revenues earned from policy support or state mandated renewable energy credit (REC) programs cannot be discounted from the MOPR price. The resulting MOPR price is high enough that many new clean energy resources will fail to clear the capacity market. The (flawed) logic used to justify this expansion of MOPR is that, without it, policy-supported resources would unfairly reduce capacity prices; under this theory, the MOPR "corrects" market prices to the higher level that would prevail absent states' policies.

We disagree with this theory. In our view, the underlying conflict is that states wish to address the harms of greenhouse gases and air quality pollutants that are not presently considered within the wholesale markets. With no means of expressing these policy requirements within the PJM markets (and given differences among states in valuing emissions reductions), states have enacted legislation to address these priorities. States have used a combination of market-oriented and non-market-oriented policies to pursue their clean energy objectives. These policies will have the intended effect of displacing fossil

[4] Federal Energy Regulatory Commission (FERC), "Order Establishing Just and Reasonable Rate," issued December 19 2019.

generation within wholesale energy and capacity markets, with a side-effect of reducing energy and capacity prices.

To the extent that policy resources fail to clear the capacity market due to the MOPR, this will deprive clean energy resources of revenues reflecting the capacity value they provide, instead favoring fossil-fired generation. It will artificially increase capacity market clearing prices relative to underlying supply-demand conditions. These effects impose excess costs on customers in two ways: first, by requiring customers to make higher clean energy program payments in order to bring clean resources online, since they will not earn a portion of their revenues from the capacity market; and second, by producing higher capacity prices that are paid to all clean and fossil plants that clear the capacity auction. For wind resources, the impacts of MOPR to reduce their total revenues are moderated by the relatively low capacity rating; for solar resources the impact of excluded revenues is much greater.

These excess customer costs are not necessary to reconcile clean energy policies with competitive markets. To the contrary, applying the MOPR to policy-supported resources undermines both the clean energy policies and the competitive capacity market itself. It undermines clean energy policies by making them more costly and by supporting excess fossil generation. It undermines the market by disconnecting market outcomes from fundamentals: ignoring the supply of policy-supported resources that are excluded from the capacity market (but still built) artificially inflates the capacity market clearing price and retains more fossil generation than needed to meet reliability targets. Over time, these distortions would become larger as the amount of policy-supported resources grows in Maryland and across the PJM footprint. The market would become a riskier and riskier proposition for investors as the market price becomes increasingly detached from fundamentals, elevated by an increasingly controversial rule.[5]

ESTIMATED IMPACTS OF THE MOPR IN MARYLAND

In Maryland, the expanded MOPR will not apply to most existing resources, but will apply to any new renewables, demand response, storage, or energy efficiency developed under current state law. If policy support were extended to the Calvert Cliffs nuclear plant, MOPR would also apply to that resource. Assuming MOPR is maintained in its current form, we estimate that the quantity of capacity resources subject to MOPR will grow from less than 500 MW today up to 1,200 MW of unforced capacity (UCAP) by 2025 and up to 1,650 UCAP MW by 2030. The quantity of resources subject to MOPR is much smaller than the 12,884 MW of installed capacity (ICAP) of renewable resources that will be needed to meet Maryland's 2030 renewable goals because existing renewables are exempt, because we assume only 500 ICAP MW of offshore wind will be developed within the applicable budget cap, and because renewables' UCAP capacity value is significantly discounted from the nameplate ICAP value.[6] Compared to a no-MOPR capacity market, this MOPR expansion may cost Maryland customers an additional $236 million per year by 2025 and $194 million per year by 2030. The exclusion of clean energy resources from clearing the capacity market will also induce the uneconomic retention of excess capacity that is not needed for reliability, primarily aging coal, oil, and gas-fired power plants that would otherwise retire.

[5] For a more complete discussion, see written testimony of Dr. Kathleen Spees and Dr. Samuel A. Newell, "The Economic Impacts of Buyer-Side Mitigation in New York ISO Capacity Market," November 18, 2020.

[6] Solar, onshore wind, and offshore wind currently have capacity value at 42%, 18%, and 26% of ICAP ratings; by 2030 we assume capacity values decline to 35%, 18%, and 22% respectively.

RESOURCE ADEQUACY ALTERNATIVES FOR MARYLAND

There are a large number of alternative market-based and planning-based approaches to supporting reliability and resource adequacy, but not all of these options are immediately available to Maryland.[7] Most importantly given the context of this study, Maryland does not have unilateral authority to simply eliminate the MOPR on policy resources within the PJM capacity market. Eliminating MOPR would require a different set of rules to be proposed by PJM or stakeholders and accepted by FERC, a reversal through federal appeals, or the adoption of new federal legislation. We anticipate that the makeup of the FERC could be favorable to the elimination of MOPR no later than mid-2021 and that appeals to overturn the expanded MOPR before the U.S. Court of Appeals for the Seventh Circuit Court could be ruled on as soon as late 2021.[8] There is also a possibility of eliminating the impacts of MOPR through broader market reform efforts, such as through PJM's recently-announced capacity market workshops to be completed by March 2021, reforms that may be initiated by New Jersey's ongoing Resource Adequacy docket, and a formal January 2021 communication from the Organization of PJM States, Inc. (OPSI) on the topic.[9] Nevertheless, in case MOPR continues to apply to policy-supported resources, Maryland will need to consider its options.

As a provision allowed within the PJM Tariff, Maryland does have the ability to exit the PJM capacity market under an FRR alternative. The FRR could be elected for individual utility zones, for the entire State of Maryland, or in collaboration with other PJM states. Once selected, Maryland would need to continue utilizing the FRR alternative for a minimum of five years.[10] Under the FRR, Maryland would have the flexibility to select and remunerate capacity resources any way it chooses, as long as the total quantity of capacity resources equals the minimum quantity PJM sets as required to meet total and locational reliability needs. The FRR alternative creates an opportunity to circumvent the application of MOPR to policy resources contracted on behalf of Maryland customers, so that the clean energy resources they support would not be excluded from supplying capacity, thus avoiding some or all of the costs imposed by MOPR. The FRR alternative is not a single design alternative, but instead is an open-ended option for Maryland to determine any and all features of how capacity needs could be met. We describe and evaluate a range of alternatives for how the FRR could be implemented, including:

- **Planning-Based FRR.** An FRR entity designated by the State would be given authority to engage in planning and bilateral contracting with capacity resources under the contract prices and terms that the FRR entity deems most favorable, subject to State oversight. The FRR entity could be directed to narrowly consider only the cost of capacity contracts in its planning activities, or could be directed to

7 For a broader discussion of alternative resource adequacy structures beyond those that we view as available to Maryland at the present time, see Pfeifenberger et al., "A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs," Prepared for PJM Interconnection, LLC, The Brattle Group, September 2009.

8 For additional analysis of the current status of MOPR and the outlook for FERC policy and appeals. See Jeff Dennis, "MOPR and More: Where the Minimum Offer Price Rule and Related Measures Stand Going Into 2021," Advanced Energy Economy, December 16, 2020.

9 See PJM Inside Lines. "PJM Announces New Series of Capacity Market Workshops". January 29, 2021; State of New Jersey, Board of Public Utilities. "Investigation of Resource Adequacy Alternatives"; and Organization of PJM States, Inc. "Resource Adequacy Letter". January 8, 2021.

10 If selecting an FRR alternative for all of Maryland or for any individual distribution territory, Maryland would be required to stay within the FRR alternative for a minimum of five years, possibly beginning with the 2024/25, 2025/26, or 2026/27 delivery year (which would require formal election of the FRR alternative by February 2022, September 2022, or March 2023 respectively). For FRR election deadlines, see PJM capacity market schedule, "Capacity Market (RPM)," 2022/23 through 2023/24 Delivery Years.

consider environmental attributes or other policy priorities. Policy resources contracted on behalf of Maryland customers would be included in the resource plan, thus circumventing MOPR application.

- **Auction-Based FRR.** An FRR entity would procure all needed capacity for Maryland under an auction-based approach, with capacity commitments selected on a least-cost basis for total and locational capacity needs. As under the planning-based FRR, policy resources would be included in the FRR plan and thus avoid MOPR application. Beyond this explicit inclusion of contracted policy resources, the FRR auction would select resources on a least-cost basis (regardless of whether the underlying resource type is fossil or clean).
- **Integrated Clean Capacity Market (ICCM).** A proposal currently under formal consideration by the New Jersey Board of Public Utilities and all New England states would replace the current capacity market with one that achieves both capacity needs and states' clean energy objectives, while eliminating the application of MOPR to policy resources. Under the ICCM, an auction administrator would conduct a joint auction to procure the resources needed to meet capacity requirements (in UCAP MW terms) and state-mandated clean energy requirements (in REC MWh terms) at the lowest combined cost. In the PJM context, the ICCM could be implemented under a Maryland-alone FRR, a multi-state FRR, or across the PJM footprint as a replacement to the current capacity market.

A key advantage of all FRR options is that they would avoid MOPR-related costs. If implemented under a Maryland-alone FRR, it is possible that only a portion of the MOPR costs would be avoided. The full costs of MOPR may not be avoided under a Maryland-alone FRR, since MOPR would still raise prices in other states and indirectly affect the price of capacity available to Maryland. The full costs of MOPR could be avoided if Maryland were to engage in a multi-state FRR or PJM-wide solution that eliminates the application of MOPR to policy resources.

The primary disadvantages across the Maryland-alone FRR options are the loss of competitive benefits from participating in a broad regional marketplace, and a number of implementation risks and costs that would arise in a smaller Maryland-alone resource adequacy structure. If implemented under a Maryland-alone FRR design, the State would face increased challenges associated with small, segmented submarkets or Locational Deliverability Areas (LDAs) separated by complex transmission constraints. These sub-markets would be prone to price volatility, lumpy resource entry and exit, exposure to the exercise of market power, and the potential for periodic reliability challenges. Additional challenges surround the interactions between the FRR-based capacity prices and prices paid in subsequent RPM auctions; capacity sellers will offer into the FRR auction at a price informed by the anticipated RPM price, including an uncertainty or risk premium. If implemented hastily or with design flaws, these structural challenges could result in an FRR structure that produces higher prices and customer costs (more than offsetting the savings from avoiding MOPR). These challenges can be at least partially addressed by utilizing best practices in auction design, robust monitoring and mitigation, and the implementation of a sloping capacity demand curve for the smallest import-constrained subregions. A multi-state FRR or PJM-wide solution would offer a better means of addressing these same challenges while maintaining access to the cost-saving benefits of broader regional competition.

The selection and compensation of the FRR entity poses another suite of challenges. The current PJM FRR rules are most naturally aligned with selecting a distribution utility as the FRR entity. We do not recommend this choice in Maryland given that this would put affiliated companies on both sides of the same capacity transaction. To avoid oversight challenges with such affiliate transactions, a state agency or independent evaluator contracted directly to a Maryland state agency could conduct any FRR capacity procurements. The FRR entity itself may be the same or different from the independent evaluator but must also be compensated for its activities including the risks it would take on as the buyer of capacity obligations and associated risk of penalties under PJM settlements.

Under the broad umbrella of the FRR, the alternative design structures differ greatly from each other; their primary advantages and disadvantages summarized in Table 1. The primary advantage of a planning-based FRR is that it would offer more leeway to the FRR entity (under State oversight) to incorporate a range of policy objectives into resource selection. This leeway is also a disadvantage however, given the increased risks of administrative forecasting errors and regulatory capture that could drive uneconomic resource selection and higher customer costs. The reliance on planning judgement and oversight is further generally inconsistent with Maryland's policies in support of competitive retail markets and competitive resource decisions.

An auction-based FRR if implemented in its simplest form and utilizing best practices in auction design is likely the lowest-cost approach and would maintain some of the benefits of a competitive capacity marketplace including competition and pricing transparency. An auction-based FRR would present a number of implementation costs and complexities associated with the complex transmission topology and small sub-markets, but is the simplest FRR option available. This approach would accommodate Maryland's policy-supported resources, but would not actively support the achievement of environmental goals (as this would be purely a resource adequacy construct).

An ICCM or similar design approach would offer all of the advantages of an auction-based FRR, plus the additional benefits of achieving enhanced competition (and lower costs) toward meeting state policy goals and the option to accelerate achievement of clean energy if costs are low. A Maryland-alone ICCM would continue to face the challenges associated with small sub-markets and complex transmission topology, with an additional disadvantage of greater implementation complexity. A multi-state or PJM-wide ICCM or similar design would address the challenges of MOPR and offer a first-best solution for supporting both reliability and clean energy, but would require regional collaboration to implement.

TABLE 1: RELATIVE ADVANTAGES OF ALTERNATIVE RESOURCE ADEQUACY DESIGN OPTIONS

DESIGN	ADVANTAGES	DISADVANTAGES
Current PJM Capacity Market *(with MOPR on Policy Resources)*	• Regional competition • Track record of reliability at low cost • No implementation costs or risks • Market power mitigation authority • Avoid FRR lock-in period • Possibility that MOPR will be eliminated in any case within a timeframe of a few years before major costs are imposed • Maintain focus on first-best regional solution	• MOPR-driven costs • MOPR maintains more aging fossil plants that are not needed for reliability and misalign with policy objectives • MOPR is inconsistent with clean energy mandates
Planning-Based FRR	• Eliminate MOPR on policy resources & mitigate MOPR cost impacts • Ability to consider a wide range of policy objectives	• Lose competitive market benefits, associated risk of less efficient planning decisions • Shift risk of uneconomic investments & contracts from generators to customers • Potential for excess influence from FRR planning entity • Aligning FRR entity and customer interests • Compensating FRR entity for risks • Misaligned with retail choice • Misaligned with market-based investments • Reduced transparency • High implementation complexity & risks • 5-year FRR lock-in period
Auction-Based FRR	• Eliminate MOPR on policy resources & mitigate MOPR cost impacts • Simplest FRR option • Multi-state approach could achieve most competitive benefits of a no-MOPR RPM	• Lose efficiency benefits of broader regional competition (unless pursuing a multi-state FRR approach) • Small sub-market challenges including exposure to price volatility, exercise of market power, and periodic reliability (mitigated with a multi-state approach) • Compensating FRR entity for risks • Medium implementation complexity & risks • 5-year FRR lock-in period
Integrated Clean Capacity Market	• Eliminate MOPR on policy resources & mitigate (not eliminate) MOPR price impacts • Greater competition among clean resources • Efficiency benefits of co-optimizing capacity and clean energy procurements • Option to accelerate clean energy achievement if prices are low • Multi-state approach could achieve most competitive benefits of a no-MOPR full RPM *plus* a regional clean energy marketplace	• Lose some regional market benefits (unless pursuing a multi-state or PJM-wide approach) • Compensating FRR entity for risks (not relevant if achieved under a regional approach) • Small sub-market challenges including exposure to price volatility, exercise of market power, and periodic reliability (mitigated with a regional approach) • High implementation complexity & risks

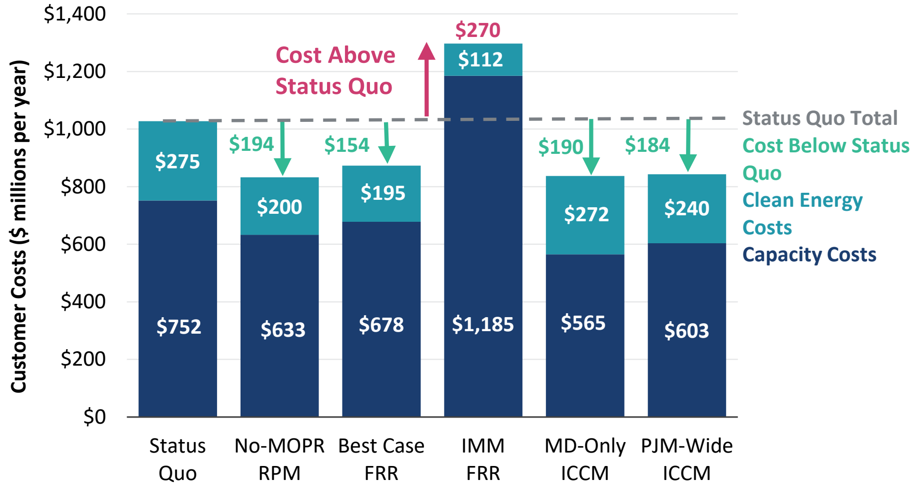
IMPACTS OF ALTERNATIVES ON CUSTOMER COSTS AND RESOURCE MIX

We conducted detailed modeling of the PJM RPM auction, MD FRR auction, and MD and PJM ICCM auctions in 2025 and 2030 to analyze the potential impacts of the various design scenarios on capacity costs, payments for clean energy, patterns of retirement and new entry, and resource supply mix. Implications for total customer costs and clean energy achievement are summarized in Figure 1, including:

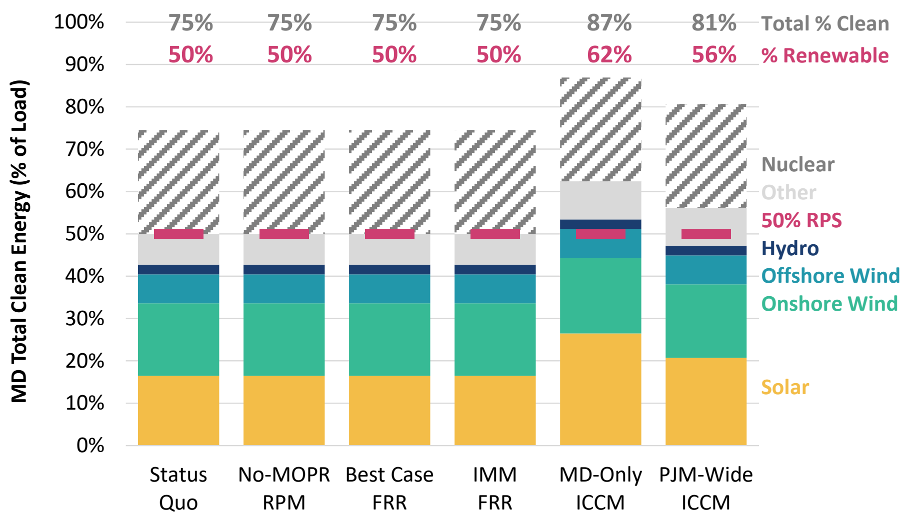
- **Best-Case Auction-Based FRR:** The best case outcome under a competitive FRR leads Maryland customers to avoid approximately 80% of the costs imposed by MOPR. There are two primary drivers of these savings: (1) customers pay for roughly 3% less capacity under the FRR, because Maryland must only procure the reliability requirement, whereas in the RPM, more capacity is procured due to the downward sloping demand curve; and (2) electing FRR allows thousands of MW of resources that cannot clear due to MOPR in the PJM RPM to provide capacity to Maryland. This unlocks clean capacity contracted for customers in Maryland and other states to serve the capacity needs under a Maryland FRR. This effectively increases the supply of capacity across the PJM footprint, lowering capacity prices and saving costs for Maryland customers and other PJM customers alike.
- **IMM-Assumed Pricing for FRR:** The substantial cost savings under a "Best-Case FRR" depends on the willingness of non-MOPR capacity suppliers to offer into the Maryland FRR at competitive prices. However, there are a number of challenges that could potentially drive higher prices such as risk-averse offers that prove to exceed the prices available in the subsequent PJM capacity auction, lack of supply participation, localized market power, or other FRR implementation challenges. If such higher prices are not addressed or are locked in via multi-year contracts (such as under a planning-based FRR), these higher FRR costs could exceed the savings from avoiding MOPR. In our modeling we adopt assumptions used by the PJM independent market monitor (IMM) in studying the potential costs of FRR, yielding costs as much as $270 million per year (in 2030) higher than under status quo.
- **Maryland-Only ICCM:** If Maryland elected the FRR and designed a single-state ICCM to procure both capacity and RECs, cost savings could be similar to those seen under a Best-Case FRR outcome. We find that such a market design could attract substantial additional clean energy resources beyond the current RPS targets if implemented with a downward-sloping demand curve for RECs. This could drive clean energy achievement above the 50% standard to 62% renewable by 2030 (from 75% to 87% total clean energy if including nuclear). This additional new entry would further reduce capacity prices in both the PJM RPM and FRR auctions. The cost savings from reduced capacity payments would roughly offset the additional payments for clean energy attributes. However, this Maryland-alone ICCM design is subject to several of the potential risks identified under the "IMM FRR" case above. As with a capacity-only FRR, the a Maryland-alone FRR would need to be implemented according to best practices and considering interactions with the subsequent PJM auctions to prevent these risks from materializing.
- **PJM-Wide ICCM:** While not a design that Maryland can unilaterally implement, a PJM-wide ICCM would achieve the benefits of avoiding MOPR costs and achieving higher levels of cost-effective clean energy deployment. Maryland could exceed its renewable standard and attract 56% renewable energy by 2030 (81% total clean including nuclear). At the same time a broad regional marketplace would mitigate the risks associated with a Maryland-alone FRR. The broad regional ICCM also amplifies the impact of downward-sloping demand curves for clean energy across the PJM footprint, increasing PJM-wide clean energy generation increases from 54% of load under the status quo to 65% of load by 2030.

FIGURE 1: CUSTOMER COSTS AND RENEWABLE GENERATION IN 2030 BY DESIGN SCENARIO

PANEL A: CUSTOMER COSTS IN MARYLAND



PANEL B: RENEWABLE GENERATION



Notes, Panel A. Clean energy resource costs include payments to new onshore wind, offshore wind, and utility-scale solar resources in excess of their energy and capacity revenues. Capacity costs include Maryland's share of PJM capacity costs (when participating in the PJM auction) or the Maryland FRR cost (when not). *Panel B:* "Other" clean energy includes Landfill Gas, Municipal Solid Waste, Agriculture Waste, Black Liquor, Other Biomass Gas, Wood/Waste Solids, and Geothermal currently providing RECs to meet Maryland RPS target today.

RECOMMENDATIONS FOR MARYLAND

In light of the many policy trade-offs and uncertainties involved, **we do not make a recommendation as to whether Maryland should adopt an FRR alternative or stay within the current PJM capacity market**. We do however offer a number of recommendations for how Maryland policymakers could proceed to maximize the customer and policy benefits in either case, while mitigating likely implementation risks.

We do **recommend that Maryland postpone any decision on the election of the FRR alternative until after key uncertainties are resolved**. Given pending changes in the makeup of the FERC, ongoing appeals (of which Maryland is a party), and ongoing regional capacity market reform initiatives, it is possible that MOPR application to policy resources could be eliminated within the next year. Under this scenario, Maryland could avoid any risks or costs associated with FRR implementation while maintaining the benefits of the broad PJM market. We recommend postponing the decision to adopt an FRR alternative until at least late 2021 when the policy stance of the new FERC may be clearer, after current appeals to the Seventh Circuit Court have been ruled upon, and after determining whether there is a viable path to a long-term sustainable capacity market design achievable through regional coordination with other states and PJM. Based on the current RPM schedule, Maryland has until February 2022 to determine whether it would elect the FRR alternative for the five-year period beginning with the 2024/25 delivery year, and will have additional decision points approximately every six month thereafter.

We offer the following **recommendations regardless of whether Maryland opts to pursue an FRR** alternative or stay within the current PJM capacity market**:**

- **Eliminate application of MOPR to policy resources**. Maryland does not have unilateral ability to eliminate the MOPR on policy resources, so we offer this recommendation more broadly. We recommend that Maryland and others continue to work through FERC proceedings, appeals, and PJM stakeholder processes to limit and ultimately eliminate the application of MOPR to policy resources, in order to avoid the market distortions and excess costs described above. Even if Maryland opts to pursue the FRR alternative, price reductions achieved by the elimination of MOPR would benefit Maryland customers via lower FRR-based capacity payments and a more attractive regional marketplace after the conclusion of the five-year FRR term.
- **Continue to pursue PJM wholesale market evolution to align with policy objectives.** In coordination with PJM stakeholders, continue to pursue a range of enhancements to the PJM wholesale market design that will align with Maryland's clean energy goals. These enhancements would likely include enhancements to scarcity pricing, ancillary service markets, capacity resource accounting, improved integration of seasonal capacity resources, and integration of emerging technologies such as storage and distributed resources. PJM already has initiatives in all of these areas.
- **Engage with other PJM states and stakeholders on an ICCM or similar proposals for long-term sustainable capacity market design.** A first-best resource adequacy market design for Maryland and other states with significant clean energy goals would continue to rely on broad regional competition for attracting a suite of resources for efficiently maintaining reliability and meeting policy goals. Even if Maryland opts to pursue an FRR alternative for a temporary period, we recommend that Maryland pursue such a first-best outcome as the most attractive long-term sustainable option. If a first-best regional market design for resource adequacy can be developed, it could be implemented through a multi-state FRR or adopted PJM-wide as a replacement to the current RPM.

With respect to an FRR construct, we caution that the net benefits (or net costs) to Maryland could vary widely depending on how it would be implemented. Under the best possible design and idealized pricing assumptions, an FRR alternative is likely to procure capacity at cost-effective prices while avoiding the customer costs from MOPR. However, we emphasize the challenges that will be associated with achieving an efficient implementation of FRR given Maryland's complex transmission topology and small segmented sub-markets. If implemented hastily, with design flaws, or with insufficient monitoring and mitigation provisions, the FRR could produce uneconomic procurement choices that induce excess capacity payments exceeding the costs of MOPR for years beyond the five-year FRR election period. We thus stress the importance of differentiating alternative FRR proposals based on their merits and implementing FRR in a deliberative fashion after robust vetting by all stakeholders and independent experts.

If Maryland decides to pursue the FRR election, we offer the following recommendations to maximize benefits and minimize risks:

- **Proceed with the formal development and evaluation of a range of resource adequacy structures, including Maryland-alone FRR and multi-state FRR options.** To preserve the option of selecting the FRR alternative if the options to stay within the PJM capacity market prove unattractive, we recommend that Maryland proceed with the formal development and evaluation of a range of viable single-state and multi-state FRR design alternatives. We recommend proceeding with this design and evaluation effort immediately in order to allow sufficient time to develop fully-considered and vetted approaches that would reduce the risk of design and implementation flaws.
- **Select an FRR design aligned with primary design goals.** If the only purpose of the FRR is to prevent policy-supported resources from being excluded from the capacity market, we recommend developing a straightforward auction-based FRR that procures capacity at least cost (without considering other resource attributes). If the State wishes to express environmental goals as well through the FRR design, then we recommend pursuing an ICCM or similar design to procure both capacity and clean energy products at the lowest combined cost.
- **Use an auction-based rather than planning-based FRR.** We recommend an auction-based approach to capacity procurement under an FRR alternative in order to preserve competitive, transparency, and cost savings benefits of the current PJM capacity market. This will minimize the role of administrative judgement in resource selection and price-setting, instead relying on a competitive format to drive efficient pricing.
- **Select a state agency or independent evaluator to implement auctions or resource selection.** To avoid challenges with affiliate transactions, we recommend that the distribution utilities not be asked to develop the FRR design, select resources, determine FRR payment prices, or determine payment terms. Instead, we recommend that a state agency or independent evaluator contracted directly with a state agency should take the role of selecting resources and payment terms.
- **Maintain unbundled capacity product for one-year commitments.** To minimize customer risks associated with uneconomic supply commitments, we recommend maintaining consistency with the current PJM capacity auction by procuring unbundled capacity credits for one-year duration. If clean energy attribute credits are also procured, these might be procured under longer-term commitments for new resources.
- **Enable competitive retailer self-supply and hedging.** Utilizing accounting mechanisms similar to the current PJM capacity market, ensure that competitive retailers within Maryland have adequate opportunities to self-supply their capacity (and, if relevant, clean energy attribute) requirements. Minimize any FRR costs that would be allocated as non-bypassable charges in order to preserve the ability of competitive retailers to identify lower-cost capacity resources for their customers.
- **Utilize best practices in resource adequacy and auction design.** We recommend adopting FRR design elements in alignment with best practices in resource adequacy design. Among these elements are a robust market monitoring and mitigation framework, sloping demand curves for the smallest LDAs, transparent rules-change processes, and (possibly) an RPM-derivative pricing component.

I. Background

As a participant in the PJM wholesale power market since its inception, Maryland has relied on the regional marketplace to provide low-cost and reliable electricity. While the regional competitive market has performed well in offering secure low-cost supply to Maryland, the PJM wholesale power market was not designed to meet Maryland's growing demand for a cleaner electricity supply mix. In recent years, Maryland has policies for a clean energy future including a 50% Renewable Portfolio Standard (RPS) by 2030 and planning a pathway toward 100% clean energy by 2040. To meet these legislative mandates, Maryland incentivizes renewable energy resources to enter the market with competitive solicitations for offshore wind, renewable energy credit (REC) markets, and various other policy incentives.

A significant disconnect has arisen between Maryland's policy goals and the PJM capacity market after a controversial order in December 2019 by the Federal Energy Regulatory Commission (FERC).[11] This ruling expanded the application of the Minimum Offer Price Rule (MOPR) by the Federal Energy Regulatory Commission to apply a higher minimum floor price to resources that receive "out-of-market" state subsidies. The expanded MOPR if maintained in its present form will limit the ability of new renewable energy resources to clear the PJM capacity market and impose excess costs on Maryland customers. As a policy, the expanded MOPR runs counter to Maryland's clean energy policies and goals.

We prepared this report for the Maryland Energy Administration (MEA) on behalf of the Maryland Energy Service to assist in identifying and evaluating resource adequacy design alternatives that could mitigate the impact of the expanded MOPR and aligns with Maryland's clean energy goals.

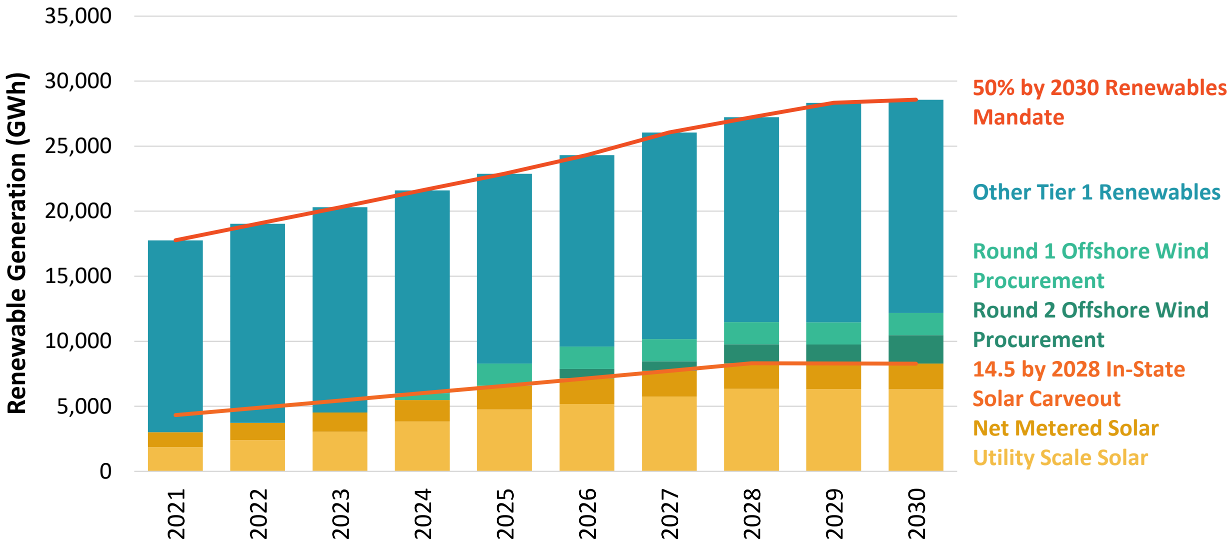
A. Maryland's Environmental Policy Goals

Maryland is a leading state in its commitment to reducing greenhouse gas emissions and eliminate fossil fuel generation from its supply mix. Under the *2019 Clean Energy Jobs Act*, Maryland adopted a 50% by 2030 RPS and will commission a study to assess the overall costs and benefits of increasing its RPS target to 100% by 2040. Figure 2 summarizes the timeframe for achieving Maryland's legislated 50% renewable energy mandate, including a 14.5% carve-out for in-state solar, and a requirement to develop least 1,590 MW of offshore wind capacity by 2030.[12]

[11] Federal Energy Regulatory Commission (FERC), "Order Establishing Just and Reasonable Rate," issued December 19 2019.

[12] Over time, Maryland increased its RPS targets with provisions for wind and solar resource carve-outs to encourage the development of renewable energy. In 2004, Maryland adopted its initial Renewable Energy Portfolio Standard (RPS) of 7.5% from Tier 1 and 2.5% from Tier 2 resources by 2019. Under the *2013 Maryland Offshore Wind Energy Act*, an initial 390 MW of capacity was procured as a part of Round 1 offshore wind projects. An additional 1,200 MW have been authorized under the *2019 Clean Energy Jobs Act* as part of the second round of offshore wind projects. The Round 2 procurement schedule of these wind projects specifies 400 MW must be procured by 2026, 800 MW must be procured by 2028, and 1,200 MW must be procured by 2030. The net rate impact for Round 2 offshore wind projects is limited to $0.88 per month for each residential customer and 0.9% of the annual electric bill for non-residential customers.

FIGURE 2: CLEAN GENERATION NEEDED TO MEET MARYLAND'S 50% BY 2030 RENEWABLE MANDATE



Sources and Notes: Maryland load is based on retail sales forecasts from the Public Service Commission of Maryland's "Ten Year Plan (2020-2029) of Electric Companies in Maryland," September 1, 2019. Round 1 offshore wind carve-out includes generation from Skipjack (120 MW) and Maryland US Windfarms (270 MW). The Round 2 offshore wind carve-out, 14.5% solar carve-out, and 50% renewable mandate are from the Maryland "2019 Clean Energy Jobs Act," SB 516, passed on May 25, 2019. The solar carve-out includes both utility-scale and net-metered solar generation. Solar carve-out, and net-metered solar cap is from "Report on the Status of Net Energy Metering in the State of Maryland." Based on apparent solar installed capacity as of end of 2020, we assume the solar carve-out is not currently being met, but that incremental solar capacity additions will come online to meet the carve-out level by 2025. Other Tier 1 Renewables includes onshore in-state wind and out-of-state onshore wind RECs. "Clean Energy Jobs," SB 516, passed on May 25 2019. Clean Energy Jobs," SB 516, passed on May 25 2019.

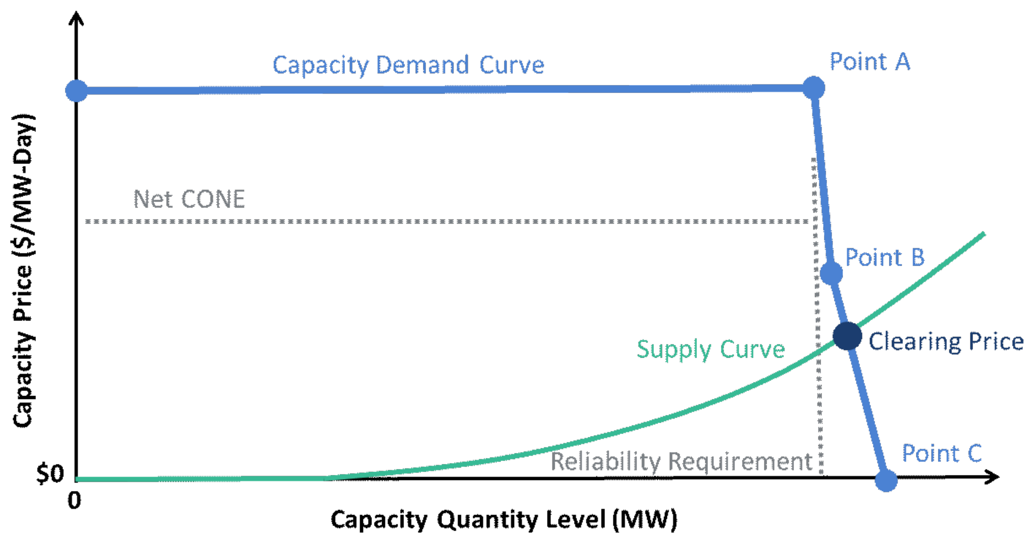
B. The Role of PJM's Capacity Market in Supporting Reliability

WHAT IS THE PJM CAPACITY MARKET?

PJM's capacity market, the Reliability Pricing Model (RPM), is a market-based system for procuring commitments from capacity resources that they will be available to meet system and locational reliability needs. The quantity of capacity procured must be sufficient to meet a reliability standard of no more than *one expected loss-of-load event in ten years* (0.1 LOLE or 1-in-10) reliability standard. PJM establishes a reliability requirement based on forecasted peak load plus the installed reserve margin (IRM) needed to maintain 1-in-10 reliability. The capacity market aims to procure sufficient generation, storage, or demand response to meet reliability needs at the lowest possible cost through the three-year forward competitive Base Residual Auctions (BRAs). The RPM uses locational pricing that reflects transmission system limitations and uses a pay-for-performance incentive structure to incentivize resources to deliver on their capacity commitments during reliability events.

PJM uses an administratively-determined Variable Resource Requirement (VRR) curve to procure capacity under the RPM, as illustrated in Figure 3. The VRR is a downward-sloping demand curve that specifies the prices and demand relative to the IRM.[13] Prices in the VRR curve are tied to the administrative estimate of the Net Cost of New Entry (Net CONE), which is the estimated price at which new generation resources would be willing to enter the market. System wide and locational VRR curves are designed to allow for the procurement of sufficient capacity to achieve resource adequacy, mitigate price volatility, and mitigate the ability for sellers to exercise market power.[14] Market participants with existing resources are required to offer available capacity into the RPM. New resources may also offer into the market as price takers or at prices that reflect their individual net costs of entering.[15] The intersection of market participant supply offers and the VRR curve sets the market price paid to all cleared capacity resources for the relevant one-year delivery period. Supply resources unable to meet their capacity commitments are subject to deficiency and penalty charges. Under this framework, RPM prices are designed to be consistent with supply-demand conditions. The RPM produces low prices when there is more than enough supply to meet resource adequacy needs and high prices when capacity supply is scarce.

FIGURE 3: ILLUSTRATIVE PJM CAPACITY SUPPLY AND DEMAND CURVES



Notes: Illustrative, not drawn to scale. See 2022/23 BRA planning parameters for specific demand curve parameters.

Historically, the PJM capacity market has been able to attract new investment and procure capacity that exceeds the reliability requirement, and at prices below the administrative estimate of Net CONE. Since the 2007/08 delivery year, 52,000 MW of new generation capacity has been attracted into the PJM capacity market; including 10,000 MW from uprates. Demand response and net import capabilities in PJM have also increased by 11,350 MW and 8,700 MW, respectively. These incremental capacity resources have been sufficient to meet increases in regional demand and replace large quantities of retirements from aging coal, nuclear, oil-fired, and high-heat rate natural gas plants.[16]

13 "PJM Manual 18: PJM Capacity Market Revision: 46," Prepared by Capacity Market & Demand Response Operations, PJM Interconnection LLC, November 2020.

14 Newell et al. "PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date," Prepared for PJM Interconnect LLC by The Brattle Group, April 2018.

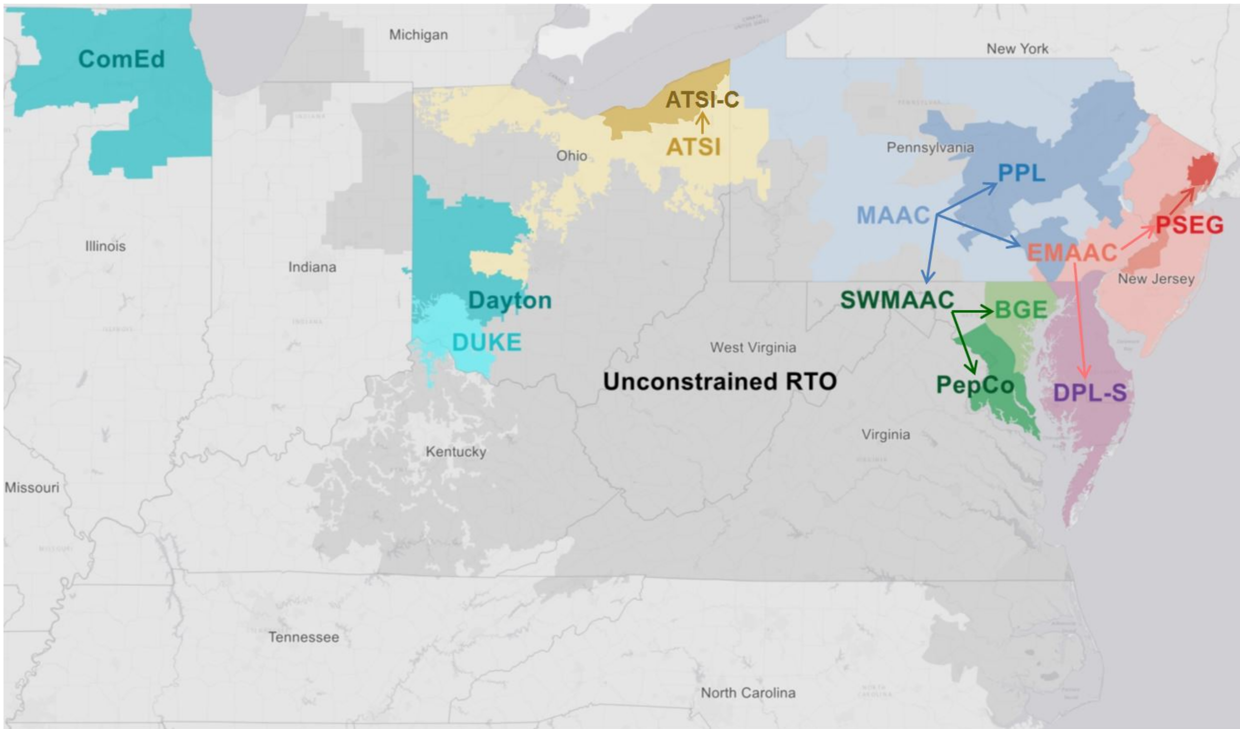
15 Seller offer prices are driven primarily by their going-forward investment and fixed costs minus any net revenues they anticipate to earn from selling other products such as energy, ancillary services, or RECs. Many capacity resources offer at a zero price if they have already come online and have few going-forward capital investments or can pre-sell most of their capacity or energy through bilateral contracts. Participants may also adjust their capacity offer price based on their long-term view of future energy and capacity prices.

16 "2021/22 RPM Base Residual Auction Results," PJM Interconnection LLC, May 2018.

HOW DOES THE CAPACITY MARKET ENSURE LOCATIONAL RESOURCE ADEQUACY FOR MARYLAND?

PJM uses the capacity market to procure capacity across the region to meet system-wide and local reliability needs at the lowest possible cost. Subregions of PJM with limited import capability due to transmission constraints are modeled as Locational Deliverability Areas (LDAs). Figure 4 shows a map of modeled LDAs in PJM.

FIGURE 4: MAP OF MODELED LOCATIONAL DELIVERABILITY AREAS IN PJM

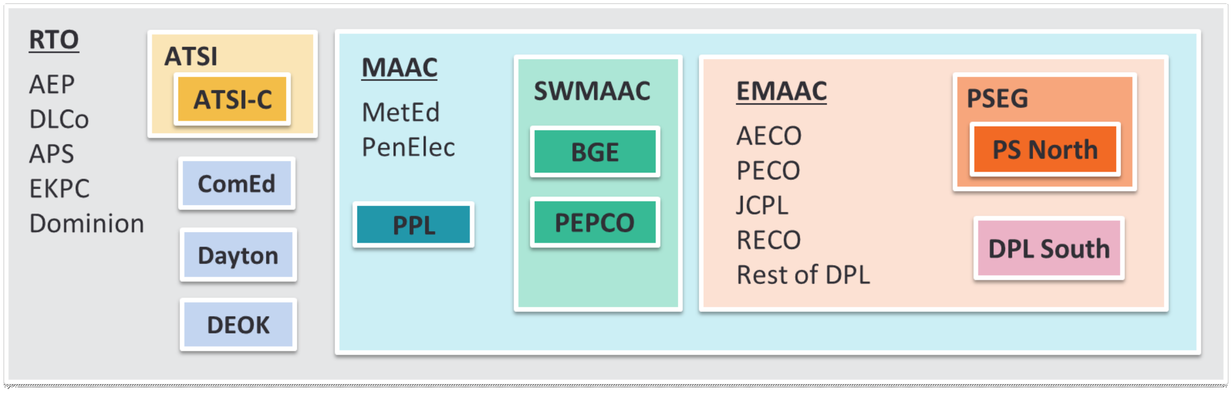


Sources and Notes: Newell et al., "Fourth Review of PJM's Variable Resource Requirement Curve," Prepared for PJM, The Brattle Group, April 19, 2018. The map represents modeled LDAs as of 2022/23.

Modeled LDAs each have a locational VRR curve, local Reliability Requirement, and locally estimated Net CONE. A "nested" LDA structure is used to reflect the transmission topology across the PJM system, in which successively smaller LDAs can procure capacity locally or from larger "parent" LDAs. Each LDA must have enough capacity procured to meet the local reliability requirements but can import a portion of that capacity from the parent LDA up to the maximum quantity that the transmission system can support or the Capacity Emergency Transfer Limit (CETL).

This complex transmission topology is illustrated in Figure 5 below. Note that modeled LDAs in the capacity market do not necessarily align with utility service territories or state boundaries. The State of Maryland comprises all or parts of seven distinct modeled LDAs, each with separate reliability parameters that must be achieved and each of which may produce distinct capacity clearing prices. The RPM auctions reflect these transmission constraints within the auction clearing by optimizing capacity imports to meet the reliability needs of all LDAs at the lowest cost. By participating in a broad regional marketplace, Maryland can save costs by importing lower-cost capacity (to the extent possible) while ensuring that sufficient local capacity will be available for reliability needs.

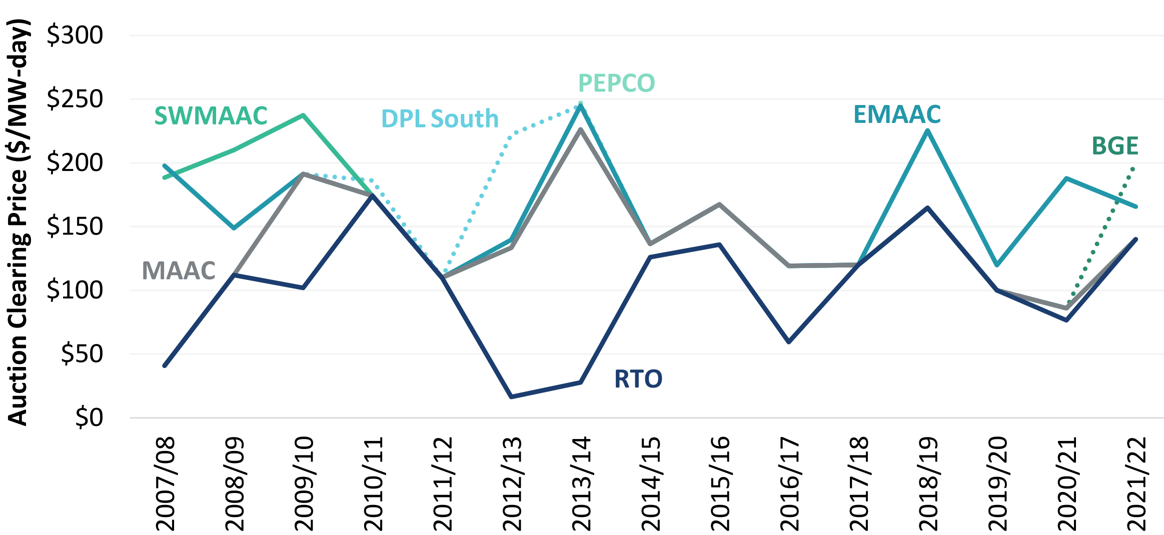
FIGURE 5: SCHEMATIC OF NESTED STRUCTURE OF LOCATIONAL DELIVERABILITY AREAS



Sources and Notes: The nested schematic is from Newell et al., "Fourth Review of PJM's Variable Resource Requirement Curve," Prepared for PJM, The Brattle Group, April 19, 2018. Each rectangle and bold label represent an LDA modeled in the 2022/23 BRA planning parameters (released in 2019, and latest as of January 2020); individual energy zones listed in non-bold without boxes are not currently modeled.

Under the RPM pricing structure, import-constrained LDAs can experience higher clearing prices relative to their parent LDAs when local reserve margins are low and due to transmission limits. This has sometimes (but not always) resulted in higher prices in the import-constrained Maryland LDAs as summarized in Figure 6. The smallest LDAs are subject to greater price volatility and occasional price spikes due to the larger price impact from small changes in supply, demand, and transmission parameters. Higher prices in constrained LDAs can serve as a signal to attract new investment in supply that is needed to support local reliability requirements, even though developing capacity resources may be more expensive in these locations.

FIGURE 6: CAPACITY CLEARING PRICES IN THE MARYLAND LDAS



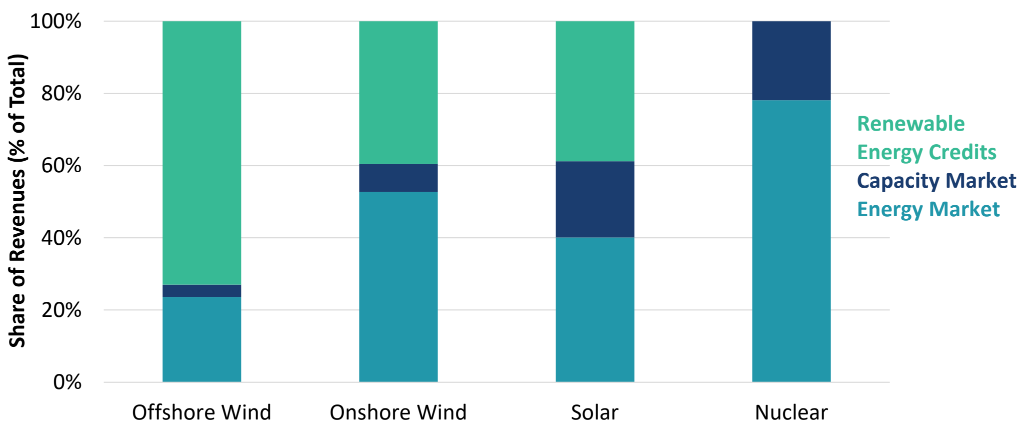
Sources and Notes: Monitoring Analytics, "State of the Market Report for PJM: Volume II, Section 5 – Capacity Market", Table 5-21: Capacity market clearing prices: 2007/08 through 2021/22 RPM Auctions, March 12, 2020.

HOW DO CLEAN ELECTRICITY MANDATES AFFECT CAPACITY MARKETS?

As of 2020, 11 out of 14 PJM states have established RPS programs to support clean energy goals.[17] While the PJM capacity market does not directly incorporate state clean energy policies, there are strong interactions between clean policy and capacity market outcomes in the interconnected regional market.

Participation in the broad PJM market is beneficial toward the efficient, cost-effective achievement of states' clean energy goals (setting aside MOPR for the moment). The wholesale electricity markets offer a ready marketplace where clean energy resources can sell energy, capacity, and (if relevant) ancillary services at a fair price. A share or even the majority of the resources' investment costs are paid for through participating in the wholesale markets, thus reducing the net cost of clean energy policy programs. For example, Figure 7 illustrates the approximate share of total resource revenues that various clean energy resources earn from the wholesale capacity and energy markets. Offshore wind, onshore wind, and solar earn anywhere from 20% to 60% of their revenues from the wholesale markets, thus requiring Maryland customers to pay only the remainder through Renewable Energy Credits (RECs) as incremental costs for pursuing clean energy goals. Worth noting given the context of MOPR, onshore and offshore wind resources earn only a small fraction of their revenues from the capacity market due to their intermittent nature and modest capacity value, meaning that the impacts of excluding them via MOPR are moderate. In contrast, solar resources earn a significant share of their total revenues from the capacity market due to relatively higher capacity value, driving an increased expense to developers (and customers) if they are excluded.

FIGURE 7: REVENUE STREAMS AVAILABLE TO CLEAN ENERGY RESOURCES



Sources and Notes: Approximate revenue streams informed by data in "2022-2023 BRA Default MOPR Floor Offer Prices for New Entry Capacity Resources with State Subsidy," PJM Interconnection, and "CONE and ACR Values – Preliminary," Monitoring Analytics, accessed February 9, 2021.

The wholesale markets further offer balancing services to complement the output profiles of intermittent resources and maintain reliability, such that the cost of integrating renewables in the PJM region has been modest to date. The "network access" approach to ensuring transmission sufficiency ensures that clean energy resources across the PJM system are simultaneously deliverable to load centers. Several

[17] "Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States," Environmental Information Services, PJM Interconnection LLC, August 2020.

jurisdictions including, Maryland, Delaware, New Jersey, and Washington, DC allow RECs to be purchased across state lines to help meet their clean energy goals and access lower-cost clean energy.[18]

State policies to support clean energy resources also impact the wholesale markets, primarily by displacing fossil resources and driving lower prices in the energy and capacity markets. Most clean energy resources have zero variable or fuel cost and so offer into the energy market at a zero or negative price, thus incrementally reducing wholesale energy prices. However, intermittent renewables participating in the capacity market face unique challenges. To maintain resource adequacy, PJM assigns renewables such as wind and solar a lower capacity value because they cannot generate at their full capacity during peak load conditions. Clean energy resources supported by policy payments tend to offer their capacity into the capacity market at a low or zero price to guarantee clearing. Clean resources do not displace fossil capacity on a one-for-one MW basis, however. They tend to have lower capacity ratings, as summarized in Table 2, given their intermittency and lower average availability to meet peak system needs.

TABLE 2: CAPACITY FACTORS AND CAPACITY VALUES OF CLEAN RESOURCES

Resource Type	Capacity Factor	Capacity Value
Nuclear	94%	99%
Solar	15%	42%
Onshore Wind	30%	18%
Offshore Wind	50%	26%
Storage	n/a	40%
Hydropower	40%	95%

Sources and Notes: Nuclear capacity value and capacity factors are approximated from S&P Global Market Intelligence and 2010-2019 historical generation from EIA 923. Capacity value for solar, wind and battery storage from Default MOPR Floor Offer Prices for New Generation Capacity Resources, p. 9, PJM Market Implementation Committee, March 11, 2020. The capacity value for hydropower approximated from the 2019 PJM Reserve Requirement Study, PJM Interconnect LLC, October 2019.

The overall effect of state policies to displace other resources in the PJM markets is mostly an intended effect from state policies, as the majority of the displaced resources tend to be fossil plants (new gas plants that will not be built and aging fossil plants that will retire). However, the lower capacity and energy prices can also have the side effect of displacing other clean resources including nuclear, demand response, existing hydropower, and storage if those resources are not eligible to compete under the relevant state policy programs.

C. The Minimum Offer Price Rule and its Application to Policy Resources

The original and proper economic purpose of the MOPR is to protect the market from the exercise of buyer market power. Specifically, schemes where large net buyers or their representatives offer a small amount of uneconomic supply into the market below cost in order to artificially suppress market-clearing prices. By taking a loss on that small position, a large net buyer could then benefit from a much larger

[18] "State RPS Fulfillment," Monitoring Analytics, October 2019.

short position in the market. The MOPR is designed to ensure that entities with the incentive and ability to engage in manipulative price suppression would be unable to do so by requiring their capacity market offers to reflect their full costs. Uneconomic new resources sponsored by large net buyers would fail to clear (or would set the prices at a higher level) and prevent the entity from achieving the benefits of manipulative price suppression. Symmetrical rules are imposed on large net sellers of capacity in order to prevent them from exercising economic or physical withholding.

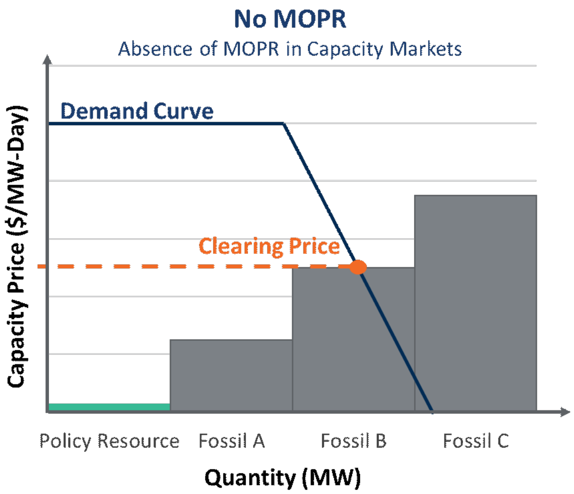
By 2011, the MOPR expanded in response to the application of state subsidies to attract natural gas capacity. In December 2019, FERC issued an order further expanding the scope of MOPR to apply to new or existing resources that receive state subsides, such as RECs or zero-emission credits (ZECs).[19] Exemptions apply only to existing resources that have previously cleared an auction or new resources that have an interconnection agreement prior to the December 2019 order. (Section II below critiques the rationale for this expansion and estimates the excess costs caused by it; here we only explain the mechanics).

Figure 8 illustrates the impact of MOPR on the ability of policy resources to clear the capacity market. The "No MOPR" scenario on the left illustrates clearing outcomes if all capacity resources are allowed to offer at their preferred offer price. Most policy resources will typically offer at a zero because these resources will be developed regardless of the capacity revenues they receive; these resources earn a large majority of their revenues through energy markets and from policy payments reflecting their environmental value. Fossil plants and other capacity resources' offers reflect the price needed to cover their net avoidable going-forward costs (that is, economic costs they will incur as a result of providing capacity in the delivery year that they would not otherwise incur). Clearing prices are set at the intersection of supply and demand, similarly to illustrative supply and demand curves in Figure 3 above.

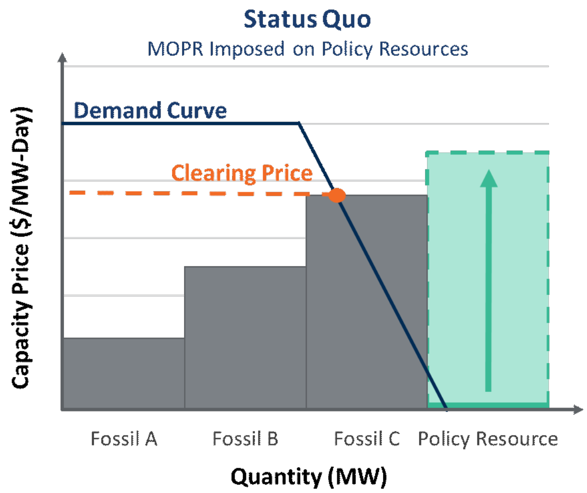
The right-hand panel, however, illustrates the status quo case where the expanded MOPR is applied to a policy resource. The offer price of the policy resource is higher than in the No MOPR scenario and reorders the capacity market offer supply curve. As the MOPR level exceeds the capacity clearing price, the policy resource does not clear, and the market's incremental need for capacity is met by fossil resource C at higher price.

[19] Federal Energy Regulatory Commission (FERC), "Order Establishing Just and Reasonable Rate," issued December 19 2019.

FIGURE 8: THE IMPACT OF MOPR ON POLICY RESOURCES



The policy resource offers at zero in the absence of MOPR to ensure clearing the capacity market.



The expansion of MOPR would artificially increase the price of the policy resource and prevent it from clearing the capacity market. As a result, the clearing price would increase.

The expanded MOPR ruling initiated extensive rehearing requests and compliance filings. As a result, there have been significant delays to the PJM capacity auction schedule; the planning year 2022/23 auction that was originally scheduled for spring 2019 will now be conducted in mid-2021.[20] Auctions for the subsequent planning years will be conducted on a compressed schedule approximately every six months until the market resumes its normal schedule with a May 2024 auction for the delivery year 2027/28.

In a parallel, there are continued efforts to eliminate the MOPR through other avenues. The composition of the FERC is changing significantly and may soon have leadership and majority members that will be favorable to the elimination of MOPR on policy resources as soon as mid-2021. In the event a new FERC would be reluctant or unable to directly reverse prior decisions, they could entertain new proposals for reforming the capacity market that would achieve the same effect. Beyond FERC itself, the U.S. Court of Appeals for the Seventh Circuit is set to begin hearings on appeals to the MOPR expansion early in 2021 with the possibility of ruling as soon as late 2021.[21]

D. The Fixed Resource Requirement Alternative

Since its inception, the RPM has included provisions for a Fixed Resource Requirement (FRR) alternative that can be utilized by any qualified entities that wish to opt out of the PJM capacity market and procure capacity in a different way on behalf of their customers. The FRR was originally designed to fit the needs of vertically integrated utilities that conduct resource planning and that do not wish to have uncertainty in the quantity of capacity requirements that can be produced by the sloped demand curve.

20 See the PJM capacity market schedule in "Update on Base Residual Auction Schedule," (Presented by PJM Interconnection to the Markets and Reliability Committee, November 19, 2020).

21 See additional discussion of the status and outlook for the expanded MOPR from Advanced Energy Economy "MOPR and More: Where the Minimum Offer Price Rule and Related Measures Stand Going Into 2021" December 16, 2020.

Though not originally intended for this purpose, Maryland can elect to exercise the Fixed Resource Requirement (FRR) alternative to limit the impact of MOPR on policy resources contracted to Maryland customers. The FRR construct requires that sufficient capacity resources be procured to meet total and location-specific capacity requirement and remains agnostic as to how the resources are procured or at what price. This mechanism would allow Maryland to circumvent the application of MOPR on policy resources.

Entities interested in participating in the FRR alternative for the first time must notify PJM at least four months before the BRA for the first delivery year the FRR alternative will be in effect. Given the currently compressed PJM auction schedule, the deadlines for FRR election are similarly compressed and accelerated. To initiate FRR beginning with the 2024/25, 2025/26 or 2026/27 delivery year would require formal election of the FRR alternative by February 2022, September 2022 or March 2023 respectively.[22] The election for the FRR alternative requires a commitment of a minimum of five consecutive delivery years. However, FRR elections can be terminated early based on the following conditions:

- PJM establishes a separate VRR curve for an LDA encompassing the FRR service area. This exception is unlikely given that most of Maryland is already modeled within separate LDAs (e.g., BGE and PEPCO).
- A state regulatory "structural change," such as the transition to a competitive retail market.

If choosing an FRR alternative, an "FRR entity" must take responsibility for securing capacity commitments on behalf of the designated customers. Table 3 summarizes the FRR obligations for the LDAs in Maryland that would be relevant for an FRR plan in the 2022/23 delivery year. A Maryland-wide FRR would need to procure approximately 14,000 UCAP MW of capacity (second to last row), of which a minimum share must be located within each of the relevant LDAs (last row). Note that the nested LDA structure means that the locational requirements are not additive. For example, any capacity within the Potomac Electric Power Company (PEPCO) LDA would contribute toward meting the PEPCO, Southwestern Mid-Atlantic Area Council (SWMAAC), Mid-Atlantic Area Council (MAAC), and Maryland-wide capacity obligations.

The FRR entity must submit an FRR plan to PJM three years in advance of delivery (and at least four months in advance of the RPM auction) to identify the specific resources committed to serving customers. If any of the identified resources would fail to fulfill its delivery obligation or incur performance penalties, the associated penalties would be assessed to the FRR entity.

TABLE 3: MARYLAND LDA FRR OBLIGATIONS AND RESOURCE REQUIREMENTS (2022/23 DELIVERY YEAR)

			RTO	MAAC	SWMAAC	BGE	PEPCO	EMAAC	DPL-S
Total LDA									
Coincident Peak Load	*(MW)*	[1]	152,505	55,042	12,391	6,285	6,106	29,914	2,203
Forecast Pool Requirement	*(%)*	[2]	108.9%	n/a	n/a	n/a	n/a	n/a	n/a
CETL	*(UCAP MW)*	[3]	n/a	2,252	9,158	6,110	7,645	9,752	1,676
Reliability Requirement	*(UCAP MW)*	[4]	166,032	65,149	15,219	7,769	8,104	36,302	2,924
Price Responsive Demand	*(UCAP MW)*	[5]	425	425	360	170	190	65	32
EE Addback	*(UCAP MW)*	[6]	3,913	1,345	229	110	119	937	17
FRR Obligations									
Min Internal Resource Requirement	*(%)*	[7]	n/a	100.0%	44.9%	24.2%	6.9%	81.5%	52.0%
Reliability Requirement adjusted for FRR	*(UCAP MW)*	[8]	152,052	52,600	10,127	6,113	3,607	35,316	1,869
Maryland Portion of LDA									
Coincident Peak Load	*(MW)*	[9]	12,841	11,527	10,416	6,285	4,131	1,111	969
Maryland Share of Coincident Peak Load	*(%)*	[10]	8.4%	20.9%	84.1%	100.0%	67.7%	3.7%	44.0%
Price Responsive Demand	*(UCAP MW)*	[11]	313	313	299	170	129	14	14
EE Addback	*(UCAP MW)*	[12]	238	203	191	110	80	12	8
FRR Obligations									
FRR Entity UCAP Obligations	*(UCAP MW)*	[13]	**13,877**	12,412	11,206	6,768	4,438	1,207	1,048
Min Internal Resource Requirement	*(UCAP MW)*	[14]	n/a	**12,412**	**5,031**	**1,638**	**306**	**983**	**545**

Sources and notes:
[1] - [5], [8], [9] – [10]: PJM BRA Auction Results Planning Parameters from the 2022/23 Delivery Year (released in 2019, and latest as of January 2020).[1] - [5], [8], [9] – [10]: PJM BRA Auction Results Planning Parameters from the 2022/23 Delivery Year
[6]: Not available for 2022/23, so used PJM BRA Auction Results Planning Parameters from the 2021/22 Delivery Year adjusted for forecasted growth in peak load.
[7]: ([4] – [3]) / ([1] x [2])
[9] = [1] x [10]
[11] = [10] x [5] for PEPCO, BGE, DPL-S, and EMAAC; SWMAAC = PEPCO + BGE; MAAC = EMAAC + SWMAAC; RTO = MAAC
[12] = [10] x [6] for PEPCO, BGE, DPL-S, and EMAAC; SWMAAC = PEPCO + BGE; MAAC = EMAAC + SWMAAC; RTO = MAAC
[13] = ([9] – [11] + [12]) x [2]
[14] = [13] x [7]

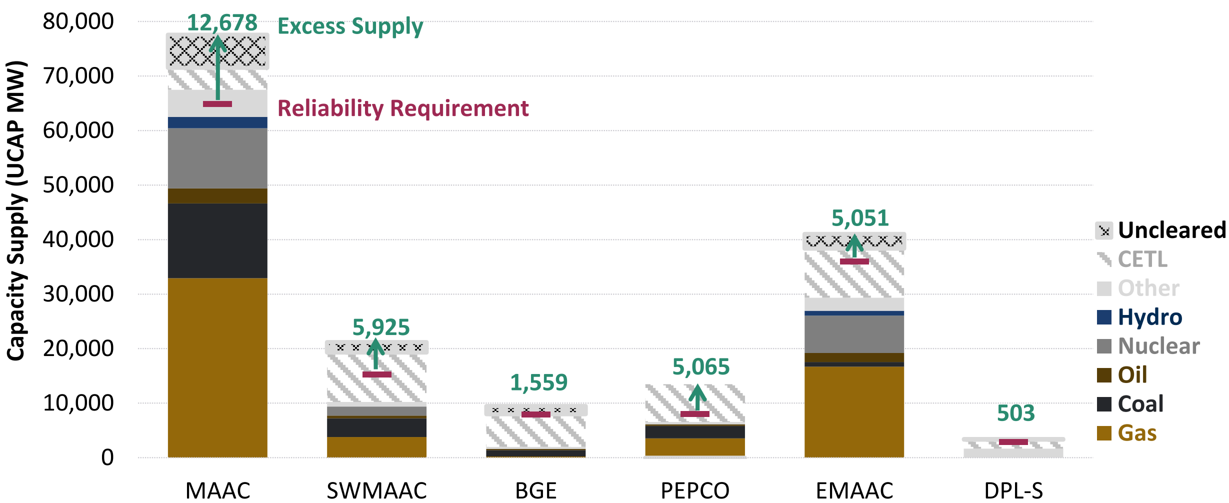
E. Structural Competitiveness of Capacity Supply

Small sub-regions of capacity markets tend to face challenges with a lack of structural competitiveness. These regions can have a relatively high cost of supply, barriers to new entry, and high ownership concentration. Maryland covers several small LDAs and thus will face some of these challenges to different degrees. Figure 9 and Figure 10 summarize the supply-demand balance and ownership share of supply resources across the Maryland LDAs. Both of these measures indicate the level of competitiveness in each

LDA. An LDA long on capacity will tend to be competitive because more supply is available to meet local needs than the minimum required and so local sellers must compete with imports. An LDA with a more fragmented ownership structure will also be more competitive. However, an LDA with a small quantity of excess supply and a single entity owning most of that supply is structurally uncompetitive. In that circumstance, a single seller could engage in economic or physical withholding, drive up local prices, and earn greater revenues on its entire portfolio of local resources. The smallest Maryland LDAs of Baltimore Gas and Electric (BGE), PEPCO, DPL-South, and SWMAAC face varying degrees of market concentration and/or tight supply, and the small size of these LDAs means that the retirement of a few large resources could tip the balance from a relatively competitive to relatively uncompetitive market structure. These locations would need to be carefully overseen from a monitoring and mitigation perspective under a Maryland FRR.

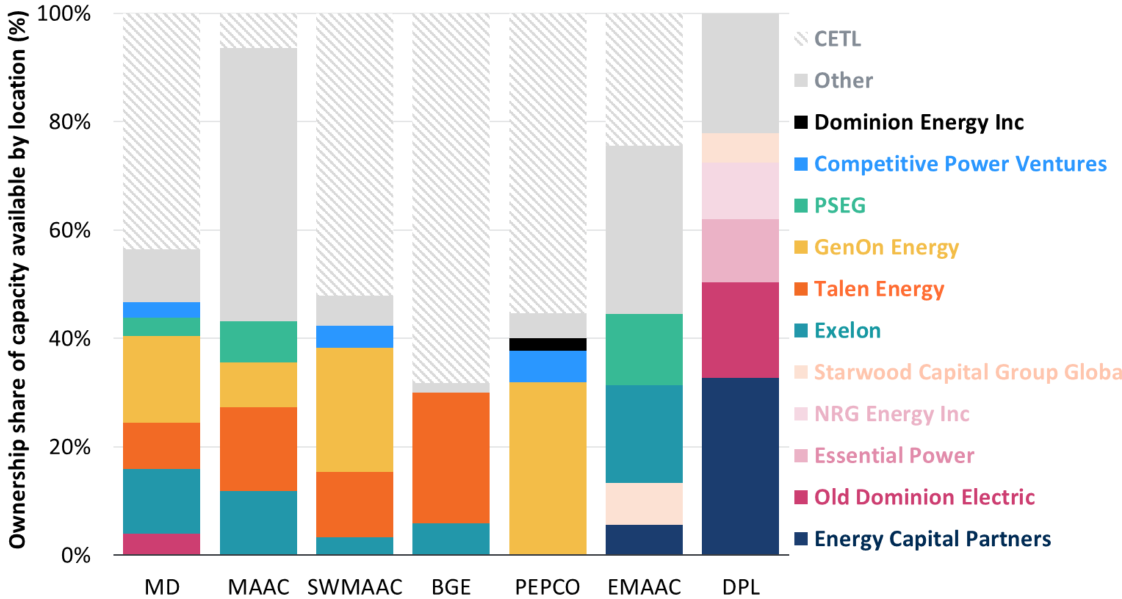
The larger LDAs including Eastern Mid-Atlantic Area Council (EMAAC), MAAC, and the portion of Allegheny Power Systems (APS) within the unconstrained RTO would not be likely to pose any market power concerns under a Maryland FRR. Maryland is a small share of total demand within these locations, each of which have supply that far exceeds Maryland demand.

FIGURE 9: CAPACITY SUPPLY AND DEMAND BALANCE



Sources and Notes: Brattle analysis based on Table 21, Monitoring Analytics, "Analysis of the 2021/22 RPM BRA: Revised," August 24, 2018 and Table 4, PJM, "2021/22 RPM BRA Results" May 23, 2018.

FIGURE 10: MARYLAND MARKET CONCENTRATION



Sources and Notes: Velocity Suite, ABB Inc., accessed January 23, 2021. The DPL zone market concentration (rather than the DPL-South LDA) is shown. Companies with market shares greater than 5% are shown.

II. Impacts of the Minimum Offer Price Rule in Maryland

A. Conflicts with State Policy Objectives

Maryland's *2019 Clean Energy Jobs Act* requires transitioning to a 50% renewable power supply by 2030, of which at least 14.5% is to be supplied by in-state solar resources and another 1,200 MW from offshore wind. The Act further requires a study of the costs of achieving a 100% clean energy supply mix by 2040.[23]

These policies reflect the public's concerns about climate change and the state's commitment to doing its share to reduce its contribution to the global problem. Absent such policies, the free market would over-produce greenhouse gases and other pollutants, since fossil-fuel-fired generators do not have to pay for the majority of the social costs that their emissions incur. It is a classic case of unpriced environmental externalities, a market failure that can only be addressed through policy mechanisms. One type of mechanism charges emitters for their emissions, through carbon taxes or cap-and-trade programs, to disfavor their production and reward non-emitters through higher market prices for energy. We and many other economists have written about the economic efficiency advantages of such an approach. However, even if carbon pricing is pursued, the political likelihood is that carbon prices may not be set high enough to support sufficient investment to meet mandated clean energy targets in the timeframe required. For

[23] Maryland State Senate, "Clean Energy Jobs," SB 516, passed on May 25 2019.

example, Regional Greenhouse Gas Initiative (RGGI) prices have been very low and are applied in only a subset of PJM states.[24] Absent a carbon price that is high enough and has a broad enough scope, Maryland and other environmentally-oriented states must use alternative means to support emissions reductions. Maryland, like other states, has used a variety of market-based approaches, long-term contracts, and other policy mechanisms to support an increasingly decarbonized supply mix.

Even though payments for clean energy attributes serve to internalize externalities and thus improve the efficiency of market outcomes, the expanded MOPR provisions consider them "subsidies" and subjects the resources to minimum offer prices. As discussed in Section I.C above, the MOPR requires policy-supported resources to offer at a price reflecting their full cost (net of energy revenues) as if they did not also receive out-of-market support reflecting their environmental value. This can prevent them from clearing the capacity market, as illustrated in Figure 8 above.

The FERC's rationale for having expanded MOPR to policy-supported resources was to "protect" prices in the competitive market from being suppressed by state-sponsored resource planning decisions. State policy-support will tend to attract incremental clean energy supply, displace fossil generation that would otherwise be built (or allow additional aging plants to retire), and reduce prevailing capacity market prices. Under FERC's theory, these lower prices amount to an artificial suppression of market prices; applying a MOPR "corrects" market prices to the higher level that would prevail absent states' policies.[25]

We disagree with this theory. In our view, state policies such as Maryland's aim to address the market failure of environmental externalities, and thus tend to guide the sector toward a more efficient outcome. Recognizing the environmental externality value of these resources, as expressed through the policy support they receive, reduces their net cost of providing capacity. Their "competitive" cost of providing capacity is thus very low or even zero as they will generally be built even if they receive no capacity payment. Imposing the MOPR on such resources and ignoring the capacity value they provide thus distorts the market, rather than correcting it. Indeed, although these resources will provide energy and contribute to supply adequacy, the MOPR causes the capacity market to procure enough non-policy resources to meet the traditional reliability requirement, as if the policy-supported resources did not exist. Excluding policy resources thus results in procuring more capacity than needed and raises prices above the level corresponding to actual supply and demand conditions. Moreover, the distortion would increase as the quantity of policy-supported resources grows. This does not make for a well-functioning market, nor one that could sustainably support investment when needed. Investors must discount a capacity price that is elevated by a controversial rule and is increasingly unstable with so much latent supply being artificially excluded. Thus, the MOPR is not a sensible policy even if one's objective is only to support competitive markets rather than to support clean energy policies.

The biggest problem with applying the MOPR to policy-supported resources is that it imposes excess costs on customers and society as a whole. It imposes costs on customers in two ways: first, by requiring customers to make higher clean energy program payments in order to bring clean resources online, since they will not earn a portion of their revenues from the capacity market; and second, by producing higher capacity prices that are paid to all clean and fossil plants that clear the capacity auction.[26] These costs might discourage Maryland from fully following through in its environmental goals. Even if not, the MOPR

[24] Maryland, Delaware, Virginia, and New Jersey are members of RGGI. Pennsylvania is considering the possibility to join RGGI.

[25] Federal Energy Regulatory Commission (FERC), "Order Establishing Just and Reasonable Rate," issued December 19 2019.

[26] See Written Testimony Of Dr. Kathleen Spees and Dr. Samuel A. Newell, "The Economic Impacts of Buyer-Side Mitigation in New York ISO Capacity Market," November 18, 2020.

would still favor non-policy-supported resources, which are mostly fossil-fired plants, to clear the capacity market and stay online rather than retire. This uneconomic support for fossil plants runs counter to the environmental objectives underpinning the adoption of Maryland's current legislation.

To summarize, applying MOPR to policy-supported resources in Maryland can be expected to lead to the following undesirable effects:

- Limitation on the ability for clean energy resources to generate revenue and interfere with Maryland's 2030 RPS.
- The retention of uneconomic fossil-fired generation that is unnecessary for reliability, impeding Maryland's efforts to achieve transition to clean electricity.
- Higher market clearing prices exceeding the level corresponding to actual supply conditions and causing a large wealth transfer from customers to incumbent suppliers.
- An unsustainable market as these distortions become larger over time under Maryland's statutory mandate to achieve 50% renewable electricity by 2030 and explore 100% clean electricity by 2040.

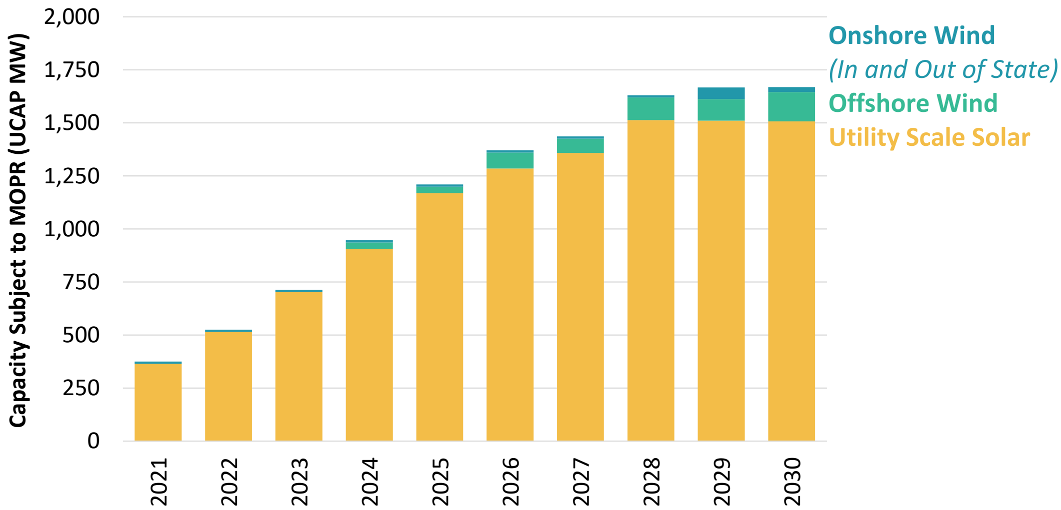
All of these challenges are amplified by the fact that several other states across the PJM region have made similarly strong commitments to clean energy including Illinois at 100% clean energy by 2050, Washington DC at 100% renewables by 2032, New Jersey at 100% clean by 2050, and Virginia at 100% renewable by 2045/2050.

B. Scale of Policy Resources Affected

The expanded scope of MOPR limits the ability for states' policy-supported renewable resources to clear the PJM capacity market. However, not all Maryland clean energy resources would be excluded by MOPR. Existing resources that previously cleared the BRA or signed interconnection agreements prior to the December 2019 order are exempt from MOPR. Resources that do not receive state subsides such as Calvert Cliffs Nuclear Facility or that do not participate in the capacity market (i.e., net-metered solar) are not subject to MOPR. Finally, resources have the opportunity to seek a unit-specific MOPR price that is lower than the PJM default MOPR price, which could enable some policy resources to clear the market even if they are subject to MOPR.

Figure 11 summarizes our estimate of the policy resources contracted to Maryland customers that will be subject to MOPR if the current rule remains in place. The total quantity of resources subject to MOPR is relatively small on a UCAP basis given the ambitious scope of Maryland's 50% renewable mandate, this is because a significant share of Maryland's anticipated clean energy resources will be eligible under the existing resource exemption, including the US Wind Project (270 ICAP MW). We assume 500 ICAP MW of Round 2 offshore wind will be developed within the applicable budget cap, reflecting current assumptions regarding the relatively high cost of building new offshore wind. New resources procured to meet the in-state solar requirement, the Skipjack offshore wind farm (120 ICAP MW), and Round 2 offshore wind procurements are assumed to be subject to MOPR. In total, the capacity subject to MOPR may grow to approximately 1,200 UCAP MW by 2025 and approximately 1,650 UCAP MW by 2030.

FIGURE 11: POLICY RESOURCES CONTRACTED TO MARYLAND CUSTOMERS SUBJECT TO MOPR



Sources and Notes: Brattle analysis based on the requirements specified in the Maryland *2019 Clean Jobs Act* and existing and proposed projects from Velocity Suite, ABB Inc., accessed January 23, 2021.

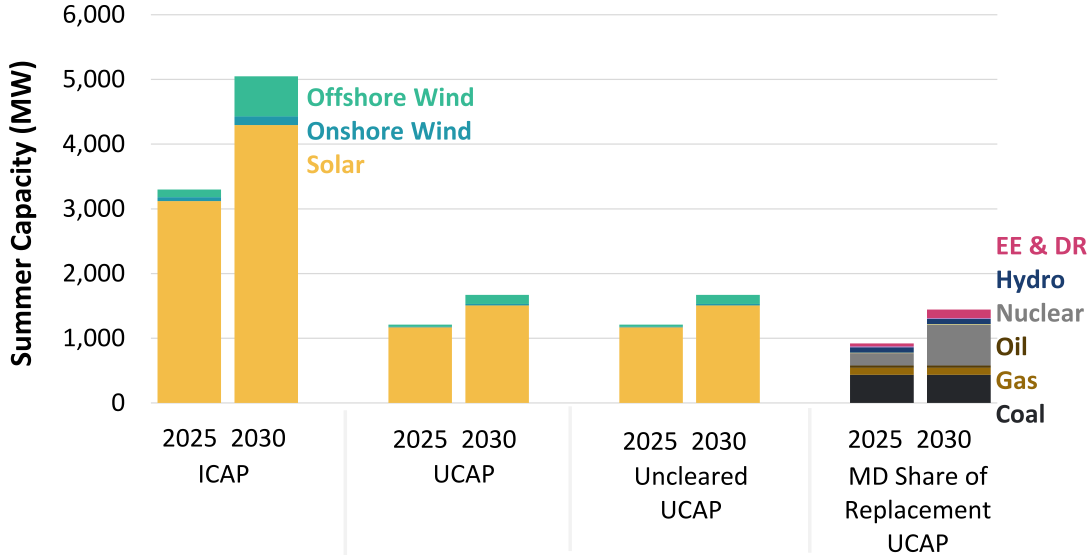
C. Impacts on Resource Mix and Customer Cost

The total quantity of resources subject to MOPR PJM-wide could be approximately 11,000 UCAP MW by 2025 and 14,000 UCAP MW by 2030. The majority of these resources are multi-unit nuclear plants earning ZECs and subject to a low or zero MOPR price and thus would be very likely to clear the capacity market. However, given current MOPR price levels (and after adjusting for projected resource cost declines), new onshore wind, offshore wind, and solar resources are unlikely to clear at projected capacity prices. Thus, on a PJM-wide basis we find that approximately 3,600 UCAP MW of policy resources are at risk of not clearing by 2025, and up to 5,800 UCAP MW by 2030.[27]

In Maryland, the MOPR will likely prevent all policy resources subjected to the MOPR from clearing the PJM capacity market. Figure 12 illustrates the contracted renewable resources subject to MOPR in Maryland in 2025 and 2030 and the market response to replace the uncleared capacity. Our analysis indicates that fossil resources are likely to replace approximately 50% of the uncleared policy resources contracted to Maryland in 2025, and 35% in 2030. Absent MOPR, these aging fossil resources would be likely to permanently retire.

[27] "2022/2023 BRA Default MOPR Floor Offer Prices for New Entry Capacity Resources with State Subsidy," PJM Interconnection LLC and "2020 Annual Technology Baseline," National Renewable Energy Laboratory.

FIGURE 12: MARYLAND CONTRACTED CAPACITY SUBJECT TO MOPR AND REPLACEMENT CAPACITY



Sources and Notes: "Maryland share of replacement UCAP" summarizes the replacement capacity resources that are uncleared under a No MOPR scenario that do clear under MOPR. It reflects Maryland's share of the incremental PJM-wide cleared capacity, calculated as the fraction of Maryland uncleared MW divided by PJM-wide uncleared MW.

Our analysis (described in further detail in section IV and in Appendix) indicates the application of MOPR to policy resources will subject Maryland customers to an additional $236 million in costs in 2025 falling to $194 million per year by 2030.[28] As outlined in Section I.C above, the application of MOPR to policy resources leads to higher capacity prices because the displaced resources subject to MOPR are replaced by more expensive resources, and fewer resources clear the capacity market overall (producing higher prices on the PJM demand curve). We estimate that average capacity prices paid by Maryland consumers would include a MOPR-driven premium of $34/MW-day in 2025 and $24/MW-day in 2030. Our estimate is consistent with or on the lower end of price impacts of MOPR presented in other studies.[29] In addition, a double payment occurs because customers are paying for capacity through the capacity market and again for renewable capacity under the Maryland RPS, further increasing the costs of MOPR.

Further, we note that the capacity market is a substantial revenue source for solar resources Maryland and across the PJM footprint, meaning that excluding solar resources from earning capacity revenues would increase the net costs of attracting these resources online. This increases the risk that solar REC prices could increase above the alternative compliance payment or exceed the applicable rate caps and

[28] See reference to PSC-Brattle MOU *supra*. The Brattle model of the PJM RPM in 2025 reflects confidential supply offer data from the 2021/22 auction, adjusted for expected retirements and new entry. For 2030, we use a synthetic supply curve based on public data and estimate the long-run average avoidable net going forward costs of supplying capacity; this 2030 supply curve is more elastic, yielding relatively lower price impacts of MOPR for the same quantity of capacity excluded by MOPR. Due to the increased supply elasticity assumed in 2030 compared to in 2025, the overall costs of MOPR are lower even though the amount of capacity subject to MOPR increases.

[29] For example, in MOPR/FRR Sensitivity Analyses of the 2021/22 RPM Base Residual Auction, the IMM estimated a $25-$234/MW-day cost reduction from FRR application to various quantities of supply subject to MOPR and other design structures. In a dissent to the December 19 2019 FERC Order which expanded the scope of MOPR to renewable sources, Commissioner Richard Glick stated a $40/MW-day price impact due to MOPR. In a webinar, ICF estimated $25-35/MW-day short term, $30-50/MW-day mid-term, and $50-70/MW-day long-term price effects due to implementation of MOPR with no additional FRR.

that the Maryland in-state solar carve outs may not be achieved. Under our study assumptions, we assume that solar costs decline quickly enough that the alternative compliance payment would be non-binding even in the presence of MOPR. However, if the pace of solar costs do not decline as rapidly as we assume, there is a risk that the loss of capacity revenues to Maryland solar resources could limit total achievement toward the in-state solar requirement due to applicable budget caps. For onshore and offshore wind, we anticipate that capacity revenues are too small a share of the total resource revenues to introduce a material impact on the ability to achieve legislative goals within the budget cap.[30]

III. Description of Resource Adequacy Alternatives for Maryland

There are a range of alternative market-based and planning-based approaches to supporting reliability and resource adequacy, but not all of these options are immediately available to Maryland.[31] Most importantly, given the context of this study, Maryland does not have unilateral authority to eliminate the MOPR on policy resources within the PJM capacity market. Maryland also does not have the unilateral authority to make other potentially beneficial changes to the RPM rules that would help it to better align with Maryland's clean energy mandates.

Maryland does have a range of options it could pursue independently through the FRR alternative including planning-based or auction-based approaches. The State has the option to include environmental mandates as a consideration within the FRR. These Maryland-alone FRR approaches could have a wide range of economic impacts, environmental outcomes, and implementation mechanics. We describe several options in this section, focusing on the subset that we anticipate would offer the greatest economic or environmental benefits to the State.

However, none of these Maryland-alone FRR alternatives is likely to offer the same level of benefits as a properly designed regional marketplace that aligns with State policy goals. Therefore, we discuss the elements of a regional adequacy design that would eliminate MOPR on policy resources, continue to ensure reliability, and support states' policy objectives.

A. Overview of Alternative Design Options

Table 4 below summarizes the status quo PJM capacity market and three qualitatively different approaches to achieving resource adequacy for Maryland without a MOPR applying to policy-support resources: through planning-based FRR, auction-based FRR, or an integrated clean capacity market (ICCM). In the following subsections, we describe the simplest possible approach to implementing each design in

30 As noted above, we assume that Maryland will procure only 500 ICAP MW of the total 1,200 MW Round 2 maximum procurement goal, but the limitation on total achievement is associated with a modest overall program budget cap as compared to the procurement goal. The incremental impact from MOPR to increase program costs is unlikely to be large enough to further limit the number of projects eventually contracted.

31 For a broader discussion of alternative resource adequacy structures beyond those that we view as available to Maryland at the present time, see Pfeifenberger et al., "A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs," Prepared for PJM Interconnection, LLC, The Brattle Group, September 2009.

Maryland, as well as the design enhancements that could improve the economic efficiency and effectiveness of each design in the context of Maryland's clean energy objectives.

TABLE 4: RELATIVE ADVANTAGES OF ALTERNATIVE RESOURCE ADEQUACY DESIGN OPTIONS

DESIGN	ADVANTAGES	DISADVANTAGES
Current PJM Capacity Market *(with MOPR on Policy Resources)*	• Regional competition • Track record of reliability at low cost • No implementation costs or risks • Market power mitigation authority • Avoid FRR lock-in period • Possibility that MOPR will be eliminated in any case within a timeframe of a few years before major costs are imposed • Maintain focus on first-best regional solution	• MOPR-driven costs • MOPR maintains more aging fossil plants that are not needed for reliability and misalign with policy objectives • MOPR is inconsistent with clean energy mandates
Planning-Based FRR	• Eliminate MOPR on policy resources & mitigate (not eliminate) MOPR price impacts • Ability to consider a wide range of policy objectives	• Lose competitive market benefits, shifting to likely less efficient planning and potential regulatory capture • Shift risk of uneconomic investments & contracts from generators to customers • Aligning FRR entity and customer interests • Potential for excess influence from FRR planning entity • Compensating FRR entity for risks • Misaligned with retail choice • Misaligned with existing market-based investments • Reduced transparency • High implementation complexity & risks • 5-year FRR lock-in period
Auction-Based FRR	• Eliminate MOPR on policy resources & mitigate (not eliminate) MOPR price impacts • Simplest FRR option • Multi-state approach could achieve most competitive benefits of a no-MOPR RPM	• Lose some regional market benefits of broader competition (unless pursuing a multi-state FRR approach) • Compensating FRR entity for risks • Medium implementation complexity & risks • 5-year FRR lock-in period
Integrated Clean Capacity Market	• Eliminate MOPR on policy resources & mitigate (not eliminate) MOPR price impacts • Greater competition among clean resources • Efficiency benefits of co-optimizing capacity and clean energy procurements • Option to accelerate clean energy achievement if prices are low • Multi-state approach could achieve most competitive benefits of a no-MOPR full RPM *plus* a regional clean energy marketplace	• Lose some regional market benefits (unless pursuing a multi-state or PJM-wide approach) • Compensating FRR entity for risks (not relevant if achieved under a PJM-wide approach) • High implementation complexity & risks

B. Status Quo RPM Capacity Market

HOW WOULD IT WORK?

The simplest option for Maryland would be to stay within the current PJM capacity market and allow private market participants to continue making resource decisions and private commitments as discussed in Section II above. Current rules would impose MOPR on an increasing quantity of policy resources committed to Maryland customers thus imposing associated costs on customers and interfering with Maryland's environmental goals.

WHAT DESIGN VARIATIONS COULD BE CONSIDERED?

Maryland does not have unilateral authority to change the design of the PJM capacity market to better accommodate State clean energy policies. It is possible, however, to influence the design through FERC proceedings, federal appeals, stakeholder processes, OPSI membership, and engagement with PJM staff. Regardless of whether Maryland chooses to pursue an FRR alternative, it would be beneficial to pursue RPM design enhancements that would better align the RPM with the needs of Maryland and other states with their environmental policies. These RPM-related enhancements could include:

- Eliminating the application of MOPR on environmental policy resources.
- Adjusting the capacity demand curve to avoid procuring excess capacity by aligning the Net CONE parameter with the true cost of new entry in the next Quadrennial review.[32]
- Considering adopting a two-season capacity market that would better enable clean energy resources that have seasonally very different capacity ratings, and would allow reduced winter procurements in the near-term (but also prepare for the possibility of higher winter loads in a long term scenario with electrified space heating).[33]
- Completing the development of an effective load carrying capability (ELCC) approach to capacity resource accreditation that more accurately measures resources' capacity value, particularly for intermittent and energy-limited resources.[34]
- Longer term, enhancing PJM's probabilistic resource adequacy modeling and its accreditation to account for flexibility-driven reliability events in addition to peak-driven reliability events.

These RPM enhancements would benefit Maryland customers if Maryland opted to continue participating in PJM's capacity market without an FRR. Even if Maryland did opt for an FRR, these enhancements would

[32] For example, one could shift the demand curve to the left while ensuring reserve margins are met. See Newell *et al.*, "Fourth Review of PJM's Variable Resource Requirement Curve," Prepared for PJM, The Brattle Group, April 19, 2018.

[33] A two-season capacity market design would enable seasonal capacity of all resource types and more accurately address seasonal capacity supply and demand in every location. This would be achieved by establishing separate reliability requirements and capacity demand curves for summer and winter needs, considering peak load and marginal cost of meeting supply in each season, thus producing efficient prices that reflect the same value per unit of avoided load shed event between seasons. See Newell et al., "Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM," Prepared for the NRDC, The Brattle Group, April 12, 2018.

[34] See "Issue Charge," PJM Interconnection, LLC, March 30, 2020 and "10.30.2020 Filing - Reliability Assurance Agreement Revisions," PJM Interconnection, LLC, October 27, 2020.

benefit Maryland customers somewhat by improving the accounting requirements that affect clean energy resources and by reducing prices in the RPM (thus indirectly reducing prices realized under an auction-based FRR).

WHAT ARE THE ADVANTAGES AND DISADVANTAGES?

There are a number of **advantages** of staying within the current PJM capacity market including:

- Path of least resistance with no implementation costs, risks, or obstacles. This approach poses none of the complexities associated with re-defining the roles and authorities of utilities, state agencies, or other entities.
- Maintaining regulatory stability for market participants.
- Maintaining the competitive benefits of participating in a broad regional marketplace (though these will be eroded over time as the scope of MOPR increases in Maryland and PJM-wide).
- Maintaining option value by deferring an FRR implementation decision until after the state gains full clarity on whether MOPR will be eliminated from the PJM market and whether a first-best regional market solution is likely to materialize.
- Maintaining state agencies' focus on other priorities, including implementation of clean energy mandates and efforts to improving the broad PJM capacity market to achieve a sustainable long-term design.

The **disadvantages** of staying within the current PJM capacity market are largely associated with the impacts of the expansive application of MOPR to policy resources, including:

- MOPR will impose excess costs on customers, with the scope of these costs growing over time along with the quantity of policy resources affected.
- MOPR will cause the uneconomic retention of existing fossil plants, counter to Maryland's and other states' environmental policy goals.
- Maryland has no authority to unilaterally change the RPM market design and cannot guarantee the success of any efforts invested in improving the design.

C. Planning-Based Fixed Resource Requirement

HOW WOULD IT WORK?

One approach to implementing an FRR in Maryland would be to designate an FRR entity and authorize it to conduct capacity planning subject to regulated cost recovery. The designated FRR entity could be a state agency, the distribution utility, an independent procurement administrator, or (more likely) some combination. The FRR entity would be selected either state-wide or individually for each distribution utility's service territory and would take responsibility for meeting the capacity needs of customers within that service territory. The processes for developing each one's FRR plan would be similar to the integrated planning activities planning activities pursued in other regulated states:

- The FRR entity would take on responsibility for developing a comprehensive resource plan that projects the full cost of electricity to customers across a range of possible outcomes and recommends a portfolio of resources and procurements for approval by a state authority.
- The recommended resource plan would account for system and local capacity needs, legislated clean energy mandates, existing contracts such as with offshore wind resources, and any other policy preferences that State regulators require to be considered such as localized pollution or employment effects.
- Interveners and commission staff would scrutinize the recommended resource plan and suggest revisions.
- The FRR entity would proceed to engage in contracts to fulfill the approved resource plan. The quantity procured to fulfill the plan would likely be lower than the quantity that would otherwise be procured within the RPM market, given that FRR entities are not subject to the sloping demand curve which has tended to procure excess quantity in recent years.
- Contracted supply resources would make a capacity commitment to the FRR entity up to the quantity that they are qualified to contribute under PJM's capacity accounting mechanisms. The FRR entity would be obligated to pay the seller for these capacity commitments at the agreed-upon price; the resource would be obligated to perform under PJM's capacity obligations.
- New policy resources that Maryland contracts under all-in bundled contracts would be prioritized for inclusion in the FRR plan to avoid the application of MOPR on these resources. These already-contracted volumes would form only a portion of the total FRR plan quantities needed, with the remainder procured from other clean and fossil capacity resources located in the relevant LDAs. Capacity resources would offer to sell into the FRR plan at the price they would otherwise expect to earn by selling their capacity into the RPM; thus prices paid for capacity in the FRR would be similar to the prevailing prices in the broader PJM market.
- The FRR entity would take responsibility for all settlements with PJM under the FERC Tariff. Any non-delivery or performance penalties caused by resources under an FRR commitment would be charged to the FRR entity (and likely should then be passed back as an assessment to the individual resource creating the penalty liability).
- The FRR entity would earn compensation for conducting the resource planning, procurement, and settlement functions, including compensation for the risks and costs associated with any bilateral contracts and would earn an approved rate of return on any required resource investments.
- Costs associated with capacity procurements and FRR entity compensation would be passed on to all end-use customers as non-bypassable charges.

If the mandate to develop an FRR plan were interpreted broadly, the implementation of a planning-based FRR would mark a significant departure from current State policies that are designed to rely on competitive forces within the wholesale market to drive efficient supply-side resource investments and enable competitive retail providers to serve end use customers. Instead, the FRR entity would take on many of the responsibilities that are currently left to individual market participants reacting to price incentives. Compared to current approaches, this planning-based FRR would create greater ability to reflect a wide range of non-price policy objectives within the resource plan, greater reliance on the technical ability of the FRR entity to engage in efficient planning and contracting, and greater reliance on State agencies to develop effective oversight. To the extent that the resource plan is implemented through longer-term contracts or bundled contracts, this would shift risks away from capacity sellers and toward customers. Both sellers and customers would enjoy more pricing stability and access to lower-cost financing under such an approach, but the costs of any uneconomic planning or contracting decisions would be borne solely by customers. Overall, a broad interpretation of planning-based FRR would be a major policy shift away from markets and toward the regulated utility model.

If the mandate to develop an FRR plan were interpreted more narrowly as the task of securing least-cost capacity for a period of no more than five years, then the implications would also be more limited. In that case, the FRR entity would not be authorized to sign contracts beyond the five-year FRR election period, would be precluded from signing bundled contracts (only capacity contracts would be considered), and would not be asked to consider factors other than capacity price in contracting decisions. Even with this more limited scope, the FRR entity would still displace the role of competitive retailers in securing capacity for their own customers and insulate certain capacity sellers from market forces for the duration of the capacity contracts. However, these effects would be limited to the five-year duration of the FRR election period, after which Maryland would be able to make a new decision regarding whether to re-enter the PJM capacity market.

WHAT DESIGN VARIATIONS COULD BE CONSIDERED?

Pursuing a planning-based FRR approach would require the State to make a number of policy choices regarding how the FRR would be implemented, including:

- **Breadth of FRR Planning Goals:** As discussed above, the most limited approach would be for the FRR entity to procure capacity to fulfill FRR planning requirements for only five years, the minimum duration of the FRR provision of PJM’s tariff. A more expansive approach could allow longer-term contracts and consider a wide array of policy goals when developing a resource plan. This would mark a major shift away from reliance on the market to drive resource decisions and toward an integrated planning, however. If the State wishes to continue its policy of relying on wholesale and retail markets to achieve cost discipline and planning efficiencies, a narrow interpretation of the FRR plan would be most consistent.
- **Selection of the FRR Entity:** The PJM FRR rules align with distribution utility service territories, meaning that the utilities will likely need to have some role in assisting with data requirements and settlements. However, the utilities are not a natural party to make most resource contracting decisions in Maryland given their affiliate relationships with potential contractual counterparties.[35] Another option would be to task a State agency or a third party independent evaluator to select capacity commitments, then possibly transferring the obligations to each separate utility to manage settlements and penalties.
- **Geographic Scope of the FRR Election:** The choice to adopt an FRR plan would not necessarily need to be implemented across all of Maryland, but instead could be implemented within only a portion of the State if desired. This might suffice to avoid MOPR if most of the Maryland-contracted resources subject to MOPR could be utilized within the FRR plan of a single distribution utility area, to meet just that area’s capacity needs. However, the ability to do so effectively depends on transmission constraints and their relationship to where the clean resources will be located. Given the complex transmission topology affecting Maryland and the uncertainty where new in-state solar and offshore wind will be located, it is unlikely that any single distribution area(s) could serve as a catch-all FRR entity for the State.

[35] Most notably, the affiliate relationship amongst the three large utilities Baltimore Gas and Electric (BGE), Pepco, and Delmarva Power & Light (DPL) that are owned by the same parent company Exelon that owns Maryland’s largest capacity resource, the 1,756 MW Calvert Cliffs Nuclear Plant, according to S&P Global Market Intelligence.

- **How to Limit Customer Exposure to Uneconomic Contracting Choices:** Ensuring cost discipline will be a challenge under a planning-based FRR given the need to rely on the FRR entity's business judgement (and State agency oversight) to identify the most beneficial price, term, resources, and location of all capacity commitments. The FRR entity would not have a profit motive for driving down costs and so may be less likely to garner the best price as compared to the competitive market. Non-resolvable planning uncertainties will translate into risks for uneconomic contract decisions. These risks can be somewhat mitigated however if the scope of contracts is strictly limited to the five-year term, to capacity-only (not bundled) contracts, and if contracts are selected on the basis of price only rather than other considerations.
- **How to Enable Competitive Retailers:** Treating all capacity costs incurred by the FRR as non-bypassable charges would eliminate the role of competitive retailers in identifying low-cost capacity solutions on behalf of their own customers. To maintain greater consistency with retail choice, competitive retailers could be offered the opportunity to self-supply their own capacity needs by submitting resource commitments to the FRR entity in advance of any FRR commitment deadline. We note that enabling retailers in this way would be complicated and may be inconsistent with allowing the FRR entity to engage in forward or multi-year contracting.
- **How to Manage Penalty Risks:** The FRR entity responsible for settlements with PJM will face penalties if any of the FRR resources fail to deliver the promised capacity or under-perform relative to their capacity obligations. Under full RPM participation, PJM itself uses a system of credit requirements and imposes any penalties directly to individual resources' owners. In a Maryland FRR, the FRR entity would have to identify contractual means to pass these same penalty risks back to the individual resources and manage the risk of counterparty defaults (as any default on penalty payments would ultimately be passed to customers).[36]
- **How to Remunerate the FRR Entity:** The FRR entity or entities would need to be compensated for their administrative activities and for the risks they bear. Administrative activities include selecting resources within the resource plan. Risks include taking on the financial costs associated with a large number of capacity contracts (in the range of 13,000 MW and $800 million to $1 billion or more per year); and the risks of any penalties that may be assessed by PJM, to the extent that it may not be possible to fully pass on all penalties to resource owners. The State would need to determine whether a fee-for-service approach is appropriate and whether any incentive-based remuneration would be pursued as a means of achieving cost efficiency on behalf of customers.

WHAT ARE THE ADVANTAGES AND DISADVANTAGES?

The **advantages** of a planning-based FRR approach include:

- The circumvention of MOPR application on policy resources contracted to Maryland, thus avoiding the customer costs of double-paying for capacity commitments (although there are other more market-oriented ways to accomplish this, as discussed in the following section).

[36] In addition to the "financial" non-performance assessment discussed here, FRR entities also have the option to elect physical non-performance assessment prior to the delivery year. Under this option the FRR entity would be required to update its Capacity Plan in subsequent delivery years to commit additional resources, "as a penalty for those committed resources that experienced Performance Shortfalls during the Delivery Year. See PJM, "FRR Entity Physical Option for Non-Performance Assessment," May 4, 2016.

- Possible cost savings. Maryland customers could save costs indirectly in two additional ways. First, by reducing the quantity of capacity procured to the FRR minimum (rather than the greater quantity that would be procured by the sloping demand curve). And second, by causing the overall PJM-wide capacity price to fall as Maryland will enable some resources to circumvent MOPR and take more demand than supply out of the capacity market. This reduction in the PJM-wide capacity price could indirectly benefit Maryland customers by reducing the price that must be paid to attract capacity resources away from RPM and into the FRR plan. However, these savings do not guarantee customer savings overall since the FRR plan will likely provide less competitive benefits and pose greater risks of uneconomic contracts and resource investments that would have to be borne by customers.
- The ability to consider other policy objectives beyond just price when selecting resources to include within the FRR plan, such as environmental, health, or employment effects.

The **disadvantages** of a planning-based FRR approach include:

- A shift away from the broad regional market and the competitive benefits provided. Inconsistency with State policies that have favored reliance on competitive, market-based approaches to driving the resource mix.
- Correspondingly shifted risks of uneconomic FRR contracting or investment decisions from generators to customers.
- Inconsistency with Maryland's policy to enable competitive retailers to serve customers through their own supply plans (rather than relying on a regulated entity to make supply decisions).
- Complexity, cost, and incentives challenges associated with properly selecting, incentivizing, and remunerating the FRR entity or entities.
- Reduced ability to implement effective market monitoring and mitigation in the primarily bilateral capacity arrangements (particularly in small, concentrated LDAs). Seller market power could become a concern for buyers; buyer market power could become a concern for sellers.
- Some distribution utilities that might be considered as FRR entities have unregulated generation affiliates that they might be tempted to favor. Such affiliate transactions produce poor incentives from a customer perspective, given that both parties to the contract wish for a higher price (while customers wish for a lower price).
- Being locked in to a five-year FRR election period, which presents the possibility of regret (if FRR planning costs are higher than anticipated or if the broader PJM market achieves the beneficial reforms needed for a first-best solution without MOPR).
- Partially undermine the performance and effectiveness of pricing signals for capacity within the Maryland LDAs (and to a lesser extent within the broader PJM capacity market). The elimination of the sloping demand curve for Maryland customers would forgo some of the price stabilization benefits, with the greatest effects realized in the Maryland LDAs and a lesser effect realized system wide. There would also be additional regulatory uncertainties imposed on capacity resources participating in both RPM and the FRR given the lack of clarity on the structure under which they would be remunerated over a typical asset life, though the five-year lock-in period would mitigate the effects.
- Reduced transparency as compared to a centralized market.
- High implementation complexity and costs, both for the regulator and the FRR entities.

D. Auction-Based Fixed Resource Requirement

HOW WOULD IT WORK?

An auction-based approach to implementing an FRR would have some similarities with the planning-based approach described in Section III.C but would utilize a competitive auction format to procure the quantity of capacity needed to meet Maryland's FRR plan. In its simplest form, the auction-based FRR would be implemented as follows:

- Each year the FRR entity would publish the parameters of a capacity procurement auction, clarifying the quantity of capacity that it would seek to procure on behalf of Maryland customers including the minimum share of total capacity that would need to be procured within each applicable LDA.
- As under the planning-based FRR, a portion of the FRR plan would be met by resources otherwise subject to the MOPR that are contracted on behalf of Maryland customers (to the extent that State agencies have the authority to direct this commitment under contract terms).
- The FRR entity would conduct a competitive auction to procure the remaining needed capacity from any PJM-qualified capacity resource in the relevant LDAs, with the FRR auction being indifferent to whether the underlying capacity resource is clean or fossil. Policy resources subject to MOPR would likely offer into the FRR auction at a low price given that they would be unlikely to earn capacity payments by selling into PJM's RPM auction. Other capacity resources would offer at prices near the expected price in the upcoming RPM auction (reflecting the opportunity cost of not selling into the PJM market). However, there would be concerns about market power, particularly if Maryland has less authority than PJM does to mitigate market power, as discussed below.
- The FRR procurement would be a single round, uniform price auction, and could produce higher prices in any LDAs for which the minimum capacity requirements are more costly to fulfill.
- The FRR entity would make a payment commitment to the cleared capacity resources and submit these cleared resources to PJM within the FRR plan. Any capacity resources that fail to clear the Maryland FRR auction would be able to offer their capacity into the subsequent BRA.
- The FRR entity would interact directly with PJM for the purposes of penalty settlements, passing any associated costs on to the individual resources.

Similar to the planning-based FRR, the auction-based approach would create an opportunity to enable resources contracted for policy purposes, and subject to MOPR, to provide capacity within the PJM footprint. This applies whether the policy resource is contracted on behalf of Maryland's customers or those of other states. The auction-based approach would maintain some advantages of the competitive PJM market including the ability to utilize market forces to procure capacity at least cost, pricing transparency, and reliance on unbundled energy, ancillary services, and capacity prices to drive resource entry and exit. Further, the one-year-at-a-time, capacity-only commitments limit the scope of cost exposure to Maryland customers. Even if FRR auction prices were to clear at an uneconomic high level in one year or in one LDA due to a design flaw or the exercise of market power, the realized high price would not be locked in over any multi-year contract terms, and any structural problems causing the uneconomic prices could be addressed in future auctions (they would not be locked in over a multi-year contract term). Oversight and compensation of the FRR entity would be far less challenging than under a planning-based FRR given that the auction procedures would be strictly delineated and approved by State authorities (minimizing the role of expert judgement or misaligned incentives in resource selection).

However, the simplest version of a Maryland-only FRR auction has a number of challenges that could make it unattractive as a permanent resource adequacy structure for the State. Maryland is a relatively small share of the PJM market and is broken into even smaller locational sub-markets for capacity, some of which have significant market concentration. This limits the scope of competition that could be achieved in a Maryland-only FRR auction. Market monitoring and mitigation would be more feasible in an auction format than in a bilateral planning-based approach but would still be more challenging due to the need to allow offers reflective of the opportunity cost of not participating in the RPM auction. The elimination of the sloping capacity demand curve could save some costs in the short term but would expose Maryland to the challenges of a vertical demand curve if maintained over a longer time period. Particularly in the smallest LDAs, the vertical demand curve in Maryland could produce higher price volatility, greater exposure to locational reliability shortfalls (or associated FRR penalties), and greater exposure to exercise of market power. Overall, the higher price volatility would produce a less attractive investment climate and so may produce less favorable outcomes over the long term as new resources are needed or existing resources need reinvestment to continue operating; based on current market conditions the BGE LDA appears most likely to face these small-submarket challenges in the near term but other LDAs could face similar challenges over time. The Maryland LDAs representing a small share of much larger PJM capacity regions would face fewer such challenges as the small volume of demand could be served by a wider array of resources and at a potentially more stable price informed by expectations in the subsequent BRA.

WHAT DESIGN VARIATIONS COULD BE CONSIDERED?

The simplest possible auction-based FRR format described here may be possible to refine in ways that would improve performance, though these enhancements also increase complexity, create a greater likelihood of implementation flaws, and at times present other trade-offs. Potential design variations include:

- **Choices Common to All FRR Variations.** As discussed above under the planning-based FRR variation, the auction-based FRR would need to establish the appropriate FRR entity, mechanisms for enabling competitive retailers, remuneration for the FRR entity, and approach to managing penalty risk.
- **Monitoring and Mitigation.** At a minimum, any FRR plan should include some means of reviewing market structure, auction competitiveness, and the potential for exercise of market power. An auction-based approach offers greater opportunities to implement effective controls on the exercise of market power, to the extent that a state agency has the authority to implement them. If Maryland has the authority, it would be beneficial to impose a capacity must-offer requirement and appropriate capacity offer caps on suppliers within the smallest import-constrained LDAs (BGE, Pepco, SWMACC, and DPL-South). The offer caps would need to be high enough to reflect all resource net going forward costs (including the expected opportunity cost of not selling capacity into the subsequent RPM auction).
- **LDA Sloping Demand Curves.** To the extent that the FRR auction would be utilized to support resource adequacy over an investment or reinvestment cycle, a sloping demand curve would benefit the sustainability of the design. Adopting a well-designed curve for the smallest LDAs within Maryland (SWMAAC, Pepco, BGE, and DPL-South) could provide a more sustainable basis for investments and maintaining locational reliability. For the portions of Maryland that can be served from resources in

EMAAC, MAAC and Rest of RTO, the interaction with the broader market will provide this price-stabilizing benefit even if Maryland maintains a vertical demand curve under the FRR auction.[37]

- **RPM-Derivative Pricing.** Most sellers in the FRR auction would likely offer at their opportunity cost of not selling capacity in the subsequent RPM auction. However, sellers will not know the upcoming RPM clearing price and so would have some uncertainty as to the best offer price in the Maryland FRR. If sellers guess systematically low, Maryland customers could benefit from a one-off discount to their capacity payments. If sellers guess systematically high (particularly in any constrained sub-LDAs), Maryland customers may have to pay an uneconomically high price for that one year. The "RPM-derivative pricing" concept proposed in the context of the New Jersey resource adequacy docket would seek to reduce this problem by accepting offer prices expressed as a percentage of the subsequent RPM price, thus protecting customers from uneconomic high prices (but also forgoing the possible benefits of low-price FRR outcomes). We note that this concept poses other complexities and challenges that would need to be addressed before being further considered in Maryland, particularly as associated with locational price differences and resources that have a minimum absolute payment needed to take a capacity commitment.[38]
- **Multi-State FRR Auction.** If Maryland were to consider an auction-based FRR as a permanent resource adequacy design, it would be beneficial to consider whether a multi-state FRR auction could become possible. Particularly if pursued alongside other states representing demand in the same LDAs, Maryland could increase access to the competitive benefits of a broader regional marketplace and mitigate challenges associated with operating a smaller sub-market.

WHAT ARE THE ADVANTAGES AND DISADVANTAGES?

The **advantages** of an auction-based FRR approach include:

- Circumvent MOPR on Maryland policy resources and mitigate some (but not all) of the costs of MOPR, similar to the other FRR options.
- Simplest possible approach to implementing FRR, reducing the risk of design flaws, especially if borrowing most auction rules from the PJM RPM.
- Reliance on a well-designed competitive auction approach maintains some of the benefits of the PJM capacity market including transparency, use of market forces to incentivize cost discipline, and auction format designed to attract a least-cost set of capacity commitments.
- If pursued through a multi-state FRR auction and with design enhancements such as sloped demand curves and comprehensive market monitoring and mitigation, an FRR alternative could form a sustainable long-term resource adequacy structure. If utilized broadly enough, the multi-state FRR could offer most or all of the competitive benefits of a no-MOPR PJM capacity market.

The **disadvantages** of an auction-based FRR approach include:

- Similar to other FRR options, implementation costs and challenges associated with managing penalty risks, settlements, and selecting an FRR entity (though fewer challenges than under a planning-based

[37] We do note that maintaining a vertical demand curve in these locations would make Maryland a bit of a free rider in terms of its ability to lean on the broader RTO market to pay for the price-stabilizing benefits of the system demand curve.

[38] See the full description of the RPM derivative pricing concept in "Independent Market Monitor Report on PSEG FRR 2.0, NJBPU Investigation of Resource Adequacy Alternatives," IMM, November 23, 2020.

approach, given the more prescriptive nature of the procurement that minimizes reliance on the FRR entity's business judgement).

- Losing the benefits of regional competition from participating in the broad PJM marketplace (unless Maryland identifies a way to pursue a multi-state FRR auction).
- Inefficiencies associated with capacity price uncertainties between the FRR auction and the RPM auction (potentially exposing customers to somewhat higher capacity prices in the FRR auction if potential sellers overestimate expected RPM auction prices).
- Challenges in preventing the exercise of market power in small concentrated LDAs.
- Challenges in addressing price volatility and supporting efficient price formation in small LDAs due to small sub-market size, lumpy nature of capacity investments, and lack of a sloping demand curve.
- Lock in to the five-year FRR commitment period, which may become unattractive if the MOPR is eventually eliminated from the PJM market.
- Implementation cost and complexity (though less complicated than a planning-based or ICCM-based FRR); developing the auction-based FRR into a more sustainable long-term design may further increase complexity.

E. Integrated Clean Capacity Market

HOW WOULD IT WORK?

The Integrated Clean Capacity Market (ICCM) is a resource adequacy alternative that is under active consideration by New Jersey and the New England region as a means of eliminating the MOPR on policy resources and better aligning the capacity market with state decarbonization policy goals.[39,40] The ICCM would build on the successes of the current capacity market with a new resource adequacy construct designed to meet both capacity and clean energy policy goals in a single procurement auction. The auction would procure two separate products: (1) capacity, denominated in UCAP MW and differentiated by location as in today's capacity market; and (2) renewable energy credits (RECs) or clean energy attribute credits (CEACs), denominated in MWh of clean energy attributes that can contribute toward Maryland's renewable portfolio standard. It could be implemented for a single state or a group of states.

Adapting the ICCM concept into Maryland's context, the design could be implemented as follows:

- A Maryland-alone ICCM could be unilaterally pursued under the FRR election option, under similar implementation choices as discussed under the prior two FRR design options. An FRR entity would need to be identified to implement procurement auction procedures, likely an independent entity that is not affiliated with any Maryland capacity resources, clean energy resources, or utilities.
- A multi-state or PJM-wide ICCM would achieve greater efficiencies by maintaining access to the broadest regional competition for both capacity and clean energy needs. This could be implemented

39 See the "Investigation of Resource Adequacy Alternatives Docket No. EO20030203," Prepared for State of New Jersey Board of Public Utilities, The Brattle Group, January 2021.

40 See Spees, "The Integrated Clean Capacity Market: A Design Option for New England's Grid Transition," October 1, 2020.

either under a multi-state FRR or through collaboration with PJM in enhancing or replacing the current RPM design.

- PJM would continue to establish the total and locational capacity requirements as well as resources' accreditation for meeting these requirements (all in UCAP terms), as under current FRR procedures.
- Maryland would establish its own MWh quantities of RECs to be procured within the ICCM, consistent with State legislative mandates to achieve up to 50% renewable procurement by 2030 and considering program budgets, State carve-outs for in-state solar and offshore wind resources, and other policies. Vertical or sloping demand curves for clean energy can be established based on clean energy mandates and program budgets and would be set independently from the total and locational demand curves for capacity. See additional discussion of design variations related to clean energy demand procurement below.
- Similar to the simpler auction-based FRR, the FRR auction administrator would conduct a single joint auction to gain resource commitments three years prior to the delivery year. Unlike in the current RPM or simpler auction-based FRR, the ICCM would procure two separate products at two distinct prices for meeting the capacity needs (in UCAP MW, defined by PJM) and the clean energy needs (in REC MWh, defined by Maryland).
- Fossil resources, demand response, storage, and energy efficiency would be eligible to sell capacity only. Renewable resources (and possibly nuclear) would be eligible to sell both capacity and RECs up to the maximum resource rating. Clean energy resources would thus earn two revenue streams from the auction, one from each product.
- Resources would offer a total revenue requirement based on the minimum payment needed to make a resource commitment in the ICCM. Clean energy resources would be assumed to be indifferent as to whether payments are earned from capacity sales or REC sales (as long as total revenues exceed the resource offer price).[41] Capacity-only resources, including fossil resources, would offer only capacity value under the current offer price format of $/MW-day UCAP.
- The auction clearing process would select the least-cost resource mix to meet both capacity and clean energy needs, setting prices based on the marginal cost of supply for each product.[42]
- Existing and future contracts for clean energy and capacity resources would be pre-committed within the ICCM and thus avoid MOPR application, subject to contractual obligations (similar to the other FRR design options).
- Customers and competitive retailers would be allowed to self-supply their capacity and REC obligations within the ICCM (similar to the enabling provisions for competitive retailers under the auction-based FRR).

[41] For example, a 100 MW installed capacity (ICAP) solar resource could be eligible to sell as much as 42 UCAP MW of capacity and 131,400 MWh of CEACs (based on a 42% capacity derating and 15% energy capacity factor). The resource might offer at $61/kW-year in ICAP terms, a price at which the resource is willing to sell its entire resource eligibility of 42 UCAP MW of capacity plus 131,400 MWh of CEACs. A low capacity price would require a relatively higher CEAC price in order for the resource to earn sufficient revenue and clear the market (and vice versa: a low CEAC price would require a higher capacity price before the resource would clear).

[42] Specifically, the auction format would be a uniform-price, single-round auction. Procurements would utilize a surplus-maximizing objective function that optimizes resource selection and sets prices for each product based on the incremental cost of supply or shadow price on each auction constraint (these are standard practice as utilized in the current RPM and the auction-based FRR approach).

- Cleared capacity resources would be submitted to PJM as comprising the FRR plan, with the FRR entity taking responsibility for all PJM-assessed capacity penalties. Costs would be passed on to Maryland customers of the relevant capacity zones (no settlements would be assessed to competitive retailers to the extent that they had self-supplied capacity).
- Cleared clean energy resources would be required to fulfill their REC delivery obligations within the delivery year, with procurement costs passed on to Maryland customers in proportion to energy consumption (no settlements would be assessed to customers or competitive retailers to the extent they had self-supplied clean energy procurements).

HOW WOULD DEMAND FOR CLEAN ENERGY BE EXPRESSED?

Demand for clean energy would be expressed as either a vertical or sloping demand curve for the MWh of RECs that are to be procured on behalf of Maryland customers in the relevant delivery year. The following Figure 13 provides an illustrative example of how demand for clean energy could be expressed in Maryland for the year 2030 as consistent with State law, though there are a number of implementation variations to consider.

The demand and treatment of clean energy resources in in the ICCM could be represented as follows:

- **Total State Clean Energy Demand:** Maryland's total demand for clean energy (blue line) would be based on the total renewable energy mandate of 50% by 2030; together with existing nuclear supply (which is not eligible for clean energy payments), the total State clean energy target is 72% by 2030. A downward-sloping demand curve could be consistent with this target, with an illustrative curve here based on three demand curve points: (a) *a "target" point* at a quantity consistent with the 50% RPS goal (72% total clean energy) and target price based on the estimated cost of developing new clean energy resources, net of their anticipated energy and capacity revenues, or the "clean net cost of new entry" (Clean Net CONE); (b) *price cap* at 1.5x the Clean Net CONE and 5% below the target quantity; and (c) *a foot point* at 100% clean energy and a price of zero. The sloping curve would offer benefits including price stabilization and the ability to accelerate clean energy achievement if this can be accomplished at low cost.[43]
- **Nuclear:** Consistent with current Maryland legislation, existing nuclear would not be eligible to receive clean energy payments (but would be eligible to earn capacity payments). If at some point the State wished to incorporate nuclear resources into the ICCM, it would become an eligible resource to contribute to clean energy mandates and to earn CEAC payments, and the total clean energy procurement target would be increased by a commensurate amount. CEAC prices paid to nuclear resources could be capped at a lower level than the payments awarded to other supply resources (which would preserve some price competition between nuclear and renewable supply resources while preventing payments in excess of any total program budget).
- **In-State Solar Carve-out:** The 14.5% in-state solar carve-out would be reflected as a separate carve-out demand curve within the ICCM. Prices for in-state-solar RECs (SRECs) would clear at higher prices if that is required to attract sufficient supply, similar to how SREC prices can trade at a price premium

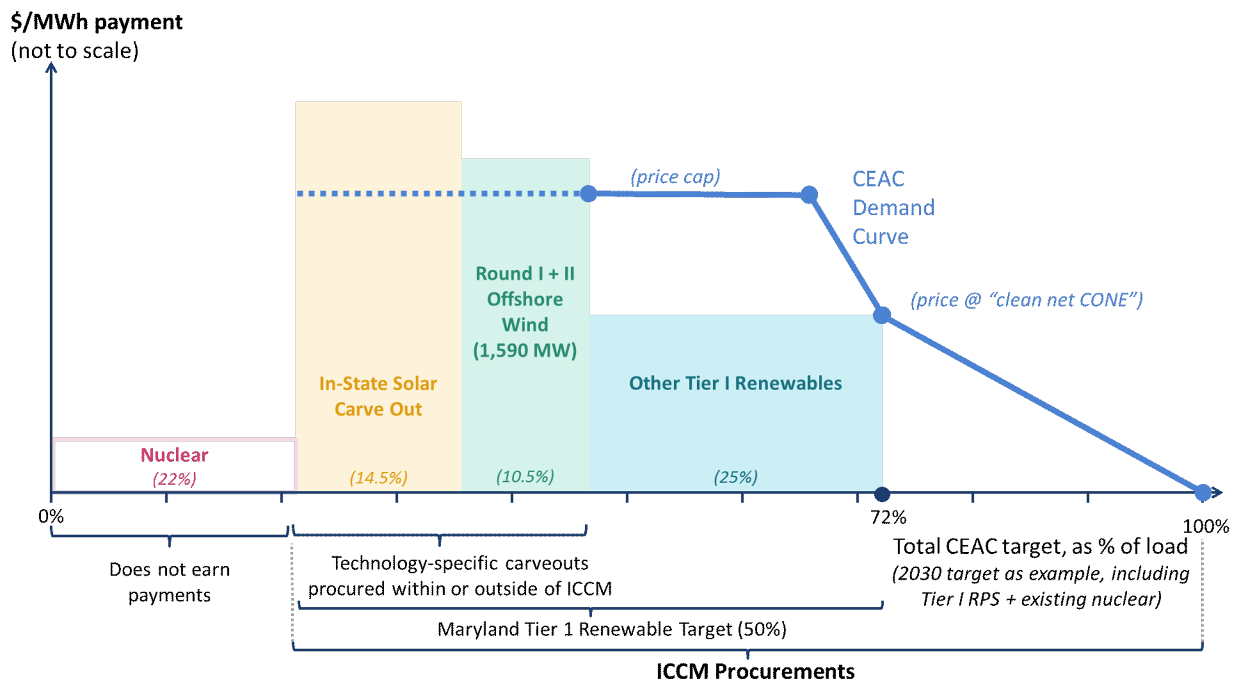
[43] See additional discussion of how a state demand curve for clean energy under the ICCM could be developed in Appendix B.1-B.2 here, and in "Investigation of Resource Adequacy Alternatives Docket No. EO20030203," Prepared for State of New Jersey Board of Public Utilities, The Brattle Group, January 2021.

relative to other Tier 1 REC prices. Retailers' private contracts for in-state solar resources would be accommodated as self-supply for SREC (and, if relevant, also for capacity) within ICCM auctions.

- **Offshore Wind:** Offshore wind could continue to be procured through State solicitations as today, with procured quantities utilized as self-supply within the ICCM auctions. This approach would allow the offshore wind resources to contribute to capacity needs and would reduce the net volume of RECs procured from other resources in the ICCM auction.
- **Other Tier 1 REC Resources:** Other clean energy resources such as onshore wind and solar that are qualified to produce Tier 1 RECs in Maryland could fulfill the remaining total clean energy demand consistent with the clean energy demand curve (with increasing quantities at lower prices).
- **Storage, Energy Efficiency and Demand Response:** These capacity-only clean resources would participate as capacity resources in the ICCM but would not earn REC payments.

Together, these approaches would enable Maryland to meet its clean energy requirements within an auction-based format alongside capacity requirements.

FIGURE 13: ILLUSTRATIVE 2030 MARYLAND DEMAND CURVE FOR CLEAN ENERGY WITHIN THE ICCM



WHAT DESIGN VARIATIONS COULD BE CONSIDERED?

If Maryland were to pursue an ICCM approach, we assume that the concept would be intended as a long-term sustainable resource adequacy design for the Maryland, multiple states, or the PJM region. Thus, the design would need to include the components of a permanent, sustainable FRR construct as described above, plus the elements of a long-term sustainable clean energy procurement mechanism. Some of the design variations that could be considered include:

- **Regional Scope, Governance, and Implementation.** A Maryland-alone or multi-state ICCM could be implemented under the current PJM Tariff rules for an FRR. As with other FRR structures, this would necessitate establishing an independent auction administrator and FRR entities to engage in settlements with PJM. A multi-state or PJM-wide ICCM could also be pursued as a regional solution to MOPR-related conflicts that could ultimately be implemented by PJM and replace the current RPM structure. The Maryland-alone approach would offer the control and certainty to State policymakers, whereas a broad regional scope would offer the greater economic and environmental benefits.

- **Price Lock-in for New Resources.** A multi-year price lock-in, such as for a 7-12-year term might be offered to provide price certainty on RECs for new resources.
- **Choices Relevant for a Long-term Sustainable Resource Adequacy Structure.** As discussed relevant to the auction-based FRR, there are a few challenges associated with developing a long-term sustainable resource adequacy design particularly as associated with small capacity areas. Robust monitoring and mitigation and well-designed sloping demand curves would help to address some of these challenges. A broader regional footprint would further support market sustainability.
- **Demand Curve for Clean Energy.** As described above, the demand curve for clean energy would need to be adapted to ensure that it conforms with state legislation and policy priorities including program budget caps, existing contracts, and appetite to procure greater quantities of clean energy if prices are low.

WHAT ARE THE ADVANTAGES AND DISADVANTAGES?

The **advantages** of an ICCM approach include:

- Similar to the other FRR options, circumvent MOPR on Maryland policy resources and mitigate the costs of MOPR.
- Similar to the auction-based FRR approach, maintain efficiency benefits of competitive auctions for capacity needs.
- Achieve enhanced competition and efficiency gains among clean energy resources.
- Efficiency benefits of co-optimizing capacity and clean energy procurements.
- Option to use clean energy demand curves to accelerate carbon abatement achievement if the cost of doing so is low.
- If pursued over a multi-state or RTO-wide approach, provide the broad competitive benefits of a regional no-MOPR capacity market plus a regional clean energy marketplace.

The **disadvantages** of an ICCM approach include:

- Exiting the PJM capacity market would forgo some of the benefits of participating in a broad regional capacity market, unless ICCM is pursued through a multi-state or RTO-wide approach. A Maryland-alone design poses greater risks of higher prices that could be caused by implementation challenges across multiple small capacity LDAs (similar to other FRR options).
- If pursuing a multi-state or regional approach, Maryland would have less control over design specifics (but could retain control over key parameters such as the quantity of clean energy procured through the ICCM).
- High implementation complexity.

IV. Economic Assessment of Resource Adequacy Alternatives

To assess the economic implications of alternative resource adequacy structures for Maryland, we utilized a model that replicates the outcomes of the PJM capacity auction under the status quo design and after any assumed design changes. We estimated the potential impacts of the various design scenarios on capacity costs, payments for clean energy, patterns of retirement and new entry, and resource supply mix in the years 2025 and 2030. In particular, we evaluated the implications for Maryland consumers under the following alternative resource adequacy scenarios:

- **Status Quo:** Maryland stays in PJM capacity market and pays the cost of MOPR on policy resources.
- **No-MOPR RPM:** Maryland stays in PJM capacity market, but MOPR is eliminated from application to state-supported clean energy resources.
- **Best-Case Auction-Based FRR:** Maryland leaves the PJM capacity market and conducts its own FRR capacity auction with the most optimistic best-case competitive pricing outcomes achieved in each respective capacity zone. In particular, we assume suppliers of capacity not subject to MOPR are willing to sell capacity in the Maryland FRR auction at prices no higher than what they would receive in the PJM market, *and* that they are perfectly able to predict their opportunity costs of not participating in the PJM market with no uncertainty.[44]
- **IMM-Assumed Pricing for FRR:** Maryland leaves the PJM capacity market, but implements the FRR under an FRR design that results in higher pricing outcomes in line with the assumptions developed by the Independent Market Monitor (IMM) in a prior analysis of a Maryland FRR.[45] These realized FRR prices we assume would be driven by some combination of sequential-auction pricing uncertainty, lack of supply participation, exercise of market power, design flaws, and/or implementation issues. Following the IMM, we assume prices reach the level of Net CONE times the balancing ratio (equal to 78% based on the PJM 2022/23 parameters).
- **Maryland-Only ICCM:** Maryland elects the FRR option and conducts its own ICCM to procure both capacity and clean energy attributes on behalf of customers under a competitive procurement approach. Other states remain in the PJM capacity market.
- **PJM-Wide ICCM:** The entire PJM region adopts an ICCM as an evolution of the current capacity market, achieving the competitive benefits of a no-MOPR full RPM plus a regional clean energy marketplace.

To estimate costs and resource mix under each of these alternative design structures, we utilize a model of the PJM capacity market that replicates locational clearing outcomes and prices. We utilize offer data from the PJM 2021/22 BRA to estimate potential outcomes, as updated to reflect future conditions anticipated by 2025 and 2030.[46] Additional modeling assumptions and results are included in Appendix.

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[44] Note that certain FRR auction structures could make it more likely to achieve this outcome, such as a design in which resources were able to express their offer prices as a percentage of the eventual PJM RPM base auction clearing prices (though the existence of multiple LDAs in Maryland limit the ability to achieve exactly this result aligned with perfect-foresight, best-case pricing).

[45] Monitoring Analytics, "Potential Impacts of the Creation of Maryland FRRs," April 16, 2020.

[46] See reference to PSC-Brattle MOU *supra*.

A. Customer Costs across Design Alternatives

Figure 14 compares the results of our Maryland customer cost analysis across the six scenarios examined in both 2025 and 2030. We find that the best-case outcome under a competitive FRR leads Maryland customers to save approximately 80% of the cost of MOPR. There are two primary drivers of these savings: (1) customers pay for roughly 3% less capacity under the FRR, because Maryland must only procure the reliability requirement, whereas under the current RPM, more capacity is procured due to the downward sloping demand curve; and (2) the FRR allows thousands of MW of resources that cannot clear due to MOPR in the PJM RPM to provide capacity to Maryland. This unlocks not only the Maryland-subsidized resources to supply capacity, but also enables MOPR-excluded policy resources from other states to sell their capacity to Maryland customers. This effectively increases the supply of capacity across the PJM footprint, lowering capacity prices both the RPM capacity market and the Maryland FRR. This produces cost savings for Maryland customers and other PJM customers alike.

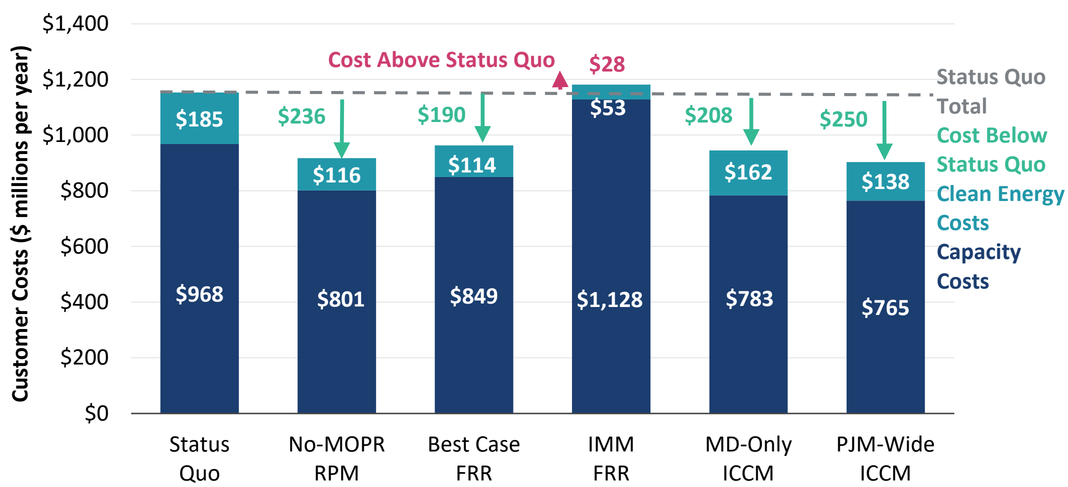
The substantial cost savings under a “Best-Case FRR” depends on the willingness of non-MOPR capacity suppliers to sell into the Maryland FRR auction at competitive prices. Non-MOPR capacity sellers should rationally offer at the anticipated price in the upcoming BRA (as they would not be willing to accept a lower price to serve Maryland than to sell into the full PJM market). If sellers could predict RPM prices perfectly or the auction could be constructed to exactly reflect sellers’ true opportunity costs, then prices would converge between the FRR auction and subsequent BRA; we assume FRR prices will have only a 5% premium over RPM outcomes in this case. There are also a number of plausible scenarios under which higher prices than the idealized Best Case FRR could materialize under a Maryland FRR. Higher prices could arise from suppliers offering at prices above later-realized RPM prices due to uncertainties, lack of supply participation, localized market power, or other FRR implementation challenges. If these outcomes were to produce higher prices near the levels previously assumed by the IMM, customer costs could increase (rather than decrease) under an FRR. Under this scenario, the cost savings achieved by avoiding MOPR on policy resources are more than offset by the higher capacity payments that exceed the pricing that would be available in the broader PJM market. If left unaddressed or locked in under long-term contracts under a planning-based FRR approach, then a poorly-design or poorly-implemented FRR could cost the same or significantly more than staying within the RPM and accepting the costs of MOPR. These pricing risks highlight the importance of thoughtful design of an auction-based FRR and avoiding any lock-in of potentially unfavorable prices.

If Maryland elected the FRR and designed a single-state ICCM to procure both capacity and RECs, cost savings could be similar to those seen under the Best-Case FRR and No-MOPR RPM. In addition to these cost savings, Maryland could also achieve the benefits of accelerated clean energy procurements under an ICCM design if implemented with a downward-sloping demand curve for RECs. This additional new entry would further reduce capacity prices in both the PJM RPM and FRR auctions. The cost savings from further-reduced capacity payments would roughly offset the additional REC payments necessary to incentivize additional renewable entry. However, this design is subject to some of the same challenges of other Maryland-alone FRR cases as relates to pricing of the capacity product. Careful implementation of the new Maryland-only ICCM would be necessary to mitigate such potential outcomes.

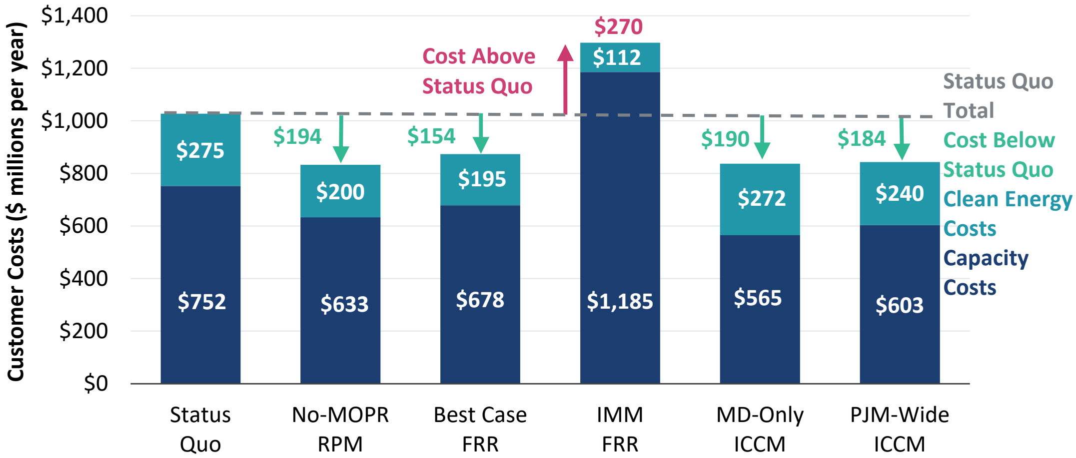
While not a design that Maryland can unilaterally implement, a PJM-wide ICCM would mitigate much of the risks of undesirable outcomes under the FRR scenarios. Costs to Maryland could be somewhat higher in a PJM-wide ICCM than under a Maryland-only ICCM, primarily because Maryland would procure more capacity by participating in the market with a downward sloping demand curve for capacity.

FIGURE 14: MARYLAND CUSTOMER COSTS BY DESIGN ALTERNATIVE

PANEL A: 2025 MARYLAND CUSTOMER COSTS



PANEL B: 2030 MARYLAND CUSTOMER COSTS



Notes: Clean energy resource costs include payments to new onshore wind, offshore wind, and utility-scale solar resources in excess of their energy and capacity revenues. Capacity costs include Maryland's share of PJM capacity costs (when participating in the PJM auction) or the Maryland FRR cost (when not).

B. Implications for Resource Mix and Clean Energy Goals

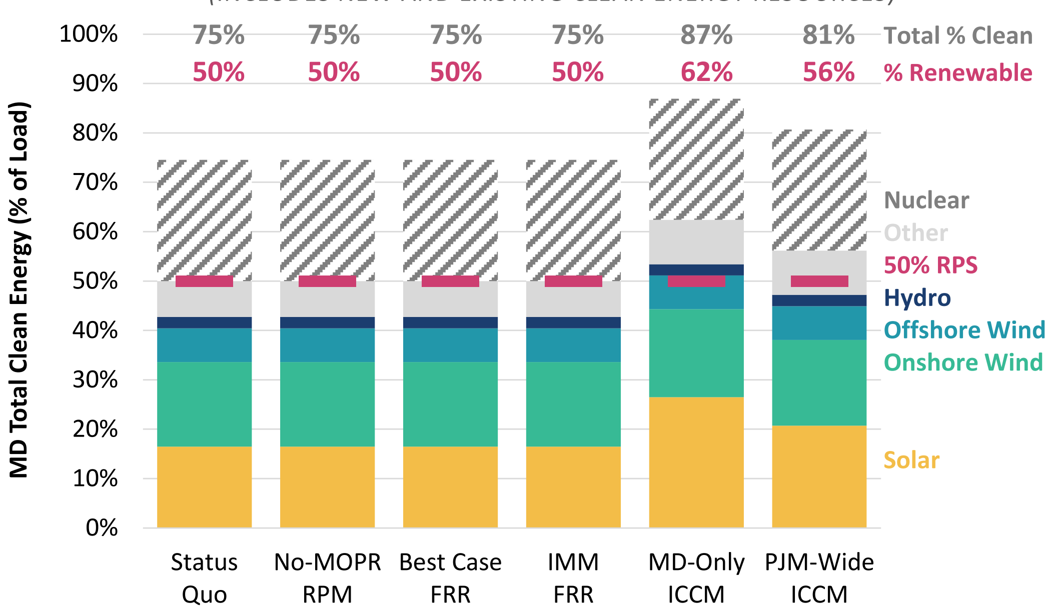
As discussed in Section II.C, we find that the exclusion of Maryland clean energy resources under MOPR could result in the maintaining of fossil and nuclear resources across the PJM footprint that might otherwise retire. However, we do not find that these factors would cause the uneconomic retention of fossil resources located within Maryland itself. Under our study assumptions, we anticipate that most fossil resources within Maryland will continue to clear the capacity or FRR structure under all scenarios analyzed either because they are needed to meet localized transmission constraints or because they remain cost-effective relative to prevailing market prices. While these fossil resources may continue to stay in operational status for capacity or reliability reasons, their generation output and associated emissions will continue to decline as more renewable supply is developed. If the pace of solar costs do not decline as rapidly as we assume in our analysis, there is also a risk that the loss of capacity revenues to Maryland solar resources could limit total achievement toward the in-state solar requirement due to applicable budget caps.

Maryland's clean energy mix (as opposed to installed capacity mix) also changes across a subset of the alternative resource adequacy structures. The volume of clean energy resources procured toward Maryland's clean energy goals does not vary across the Status Quo, No-MOPR RPM, Best Case FRR, or IMM FRR as summarized in Figure 15, as the clean energy additions are chosen to exactly meet the total RPS target, offshore wind procurements, and in-state solar carve-out. Under these scenarios, total renewable supply is equal to 50% of Maryland load (75% if including nuclear generation).

Both the Maryland-Only ICCM and PJM-Wide ICCM design scenarios procure substantially more clean energy due to the introduction of a downward-sloping demand curve that can accelerate clean energy procurement. By 2030 a Maryland-alone ICCM could attract sufficient incremental new clean resources to increase Maryland's share of load served by renewables to 62% by 2030 (or 87% including both renewables and nuclear supply).

Under a PJM-Wide ICCM, Maryland's clean energy procurement also exceeds the RPS targets, achieving 56% renewable (81% total clean including nuclear) by 2030. Under a broad regional approach, the entire PJM footprint achieves a faster pace of renewable deployment, increasing PJM-wide clean energy from 54% of load (in the Status Quo and FRR cases) up to 65% of load under a PJM-wide ICCM. These higher levels of renewable deployment tend to reduce the capacity value of the intermittent renewable supply. This, in turn, causes the marginal cost of the clean energy attribute to increase, so Maryland procures somewhat less clean energy with a downward sloping demand curve than it would under a Maryland-alone ICCM.

FIGURE 15: SHARE OF MARYLAND LOAD MET BY CLEAN ENERGY BY SCENARIO (2030)
(INCLUDES NEW AND EXISTING CLEAN ENERGY RESOURCES)



Notes: "Other" clean energy includes Landfill Gas, Municipal Solid Waste, Agriculture Waste, Black Liquor, Other Biomass Gas, Wood/Waste Solids, and Geothermal currently providing RECs to meet Maryland RPS target.

List of Acronyms

APS	Allegheny Power Systems
BGE	Baltimore Gas and Electric
BRA	Base Residual Auction
CETL	Capacity Emergency Transfer Limits
CETO	Capacity Emergency Transfer Objective
CEAC	Clean Energy Attribute Credit
ICCM	Control, Communication and Metering
DPL	Delmarva Power & Light
ELCC	Effective Load Carrying Capability
EMAAC	Eastern Mid-Atlantic Area Council
FERC	Federal Energy Regulatory Commission
FRR	Fixed Resource Requirement
FCEM	Forward Clean Energy Market
ICCM	Integrated Clean Capacity Market
IRM	Installed Reserve Margin
LDA	Locational Deliverability Area
LSE	Load-Serving Entity
MD	Maryland
MAAC	Mid-Atlantic Area Council
MOPR	Minimum Offer Price Rule
MW	Megawatt
Net ACR	Net Avoidable Cost Rate
Net CONE	Net Cost of New Entry
OPSI	Organization of PJM States, Inc.
PJM	PJM Interconnection
PEPCO	Potomac Electric Power Company
RGGI	Regional Greenhouse Gas Initiative
RTO	Regional Transmission Organization
RPM	Reliability Pricing Model
REC	Renewable Energy Credit
RPS	Renewable Energy Portfolio Standard
SREC	Solar Renewable Energy Certificate
SWMAAC	Southwestern Mid-Atlantic Area Council
MEA	Maryland Energy Administration
UCAP	Unforced Capacity
VRR	Variable Resource Requirement
ZEC	Zero-Emission Credit

Appendix: Modeling Details

Our modeling approach incorporates a number of study assumptions that may impact results. Though price and other outcomes are subject to a number of uncertainties, we have applied consistent assumptions across all studied scenarios.

Supply Offers. Our model of the PJM region in 2025 reflects confidential supply offer data from the 2021/22 auction received from PJM, adjusted for announced retirements and new entry.[47] For 2030, we have updated this supply curve based on public data and estimate the long-run average avoidable net going forward costs of supplying capacity, which yields a more elastic 2030 supply curve.[48] Consistent with recent market experience, we assume that new entry of gas combined cycle and renewable resources can be attracted at prices 20% below the administrative estimate of the net cost of new entry (Net CONE), with new resource costs projected to decline consistent with National Renewable Energy Laboratory (NREL) projections.[49] Our approach produces outcomes with greater price differences in 2025 than in 2030 can be caused by the same quantity of supply or demand changes. Our approach accounts for the fact that in the short-term capacity prices can be quite sensitive, with large prices changes driven by relatively small changes in supply or demand. However, over the longer term, extreme pricing impacts will tend to be moderated by supply exit (in the case of persistent low prices) and new entry (in the case of persistent high prices).

Demand and Transmission Parameters. We assume that policy-supported resources must to offer at least the default MOPR price when subject to MOPR. The capacity demand curve reflects the 2022/23 PJM RPM demand curve, updated to 2025/26 and 2030/31 conditions to account for changes in peak demand by LDA and anticipated changes in Net CONE. Capacity emergency transfer limits (CETL) into each LDA are assumed to stay constant throughout the study period.

Auction-Based FRR Options. The various FRR options are modeled as sequential auctions, with PJM resources offering into the FRR auction at their economic costs, including opportunity costs of not clearing the subsequent PJM BRA. In the Best-Case FRR and Maryland-Only ICCM cases we assume suppliers project RPM revenues with near perfect foresight (leading to only a 5% price premium in FRR clearing prices relative to the RPM prices in most LDAs). In the IMM-Assumptions FRR case we assume that FRR prices are set at the balancing ratio times Net CONE.[50] Capacity demand curves in the FRR are vertical at the Maryland reliability requirement.[51]

Maryland-Only ICCM. In the Maryland-Only ICCM, we assume the present offshore wind and in-state solar carve-outs to the RPS remain in place as today. In addition, we define a new demand curve for the clean energy attribute as discussed in Section III.E that reflects demand for the incremental (non-carveout) clean energy needed to meet the RPS at a $/MWh reference price given by the expected cost of new clean entry, net of energy and capacity revenues. Solar and onshore wind are assumed to be able to provide

47 See reference to PSC-Brattle MOU *supra*.

48 Monitoring Analytics, "CONE and ACR Values – Preliminary," January 28, 2020.

49 "2020 Annual Technology Baseline," National Renewable Energy Laboratory.

50 Assumption derived from the IMM study of FRR implementation in Maryland. Monitoring Analytics, "Potential Impacts of the Creation of Maryland FRRs," April 16, 2020.

51 We adjust the reliability requirement for energy efficiency and price-responsive demand in accordance with PJM's accounting for these factors in the determination of RPM demand curves.

clean energy and capacity, though the capacity value of both is assumed to decline as penetration increases. The demand curve slopes down to a point reflecting 100% clean energy at $0/MWh price. As in the simple FRR cases, we assume that capacity subject to MOPR inn the rest of the PJM footprint can also offer capacity at non-MOPR prices, subject to limits by LDA of the amount of local capacity needed to meet the FRR requirement.

PJM-Wide ICCM. In the PJM-Wide ICCM, we assume the capacity and clean energy attribute markets are co-optimized across the PJM footprint. We assume states' offshore wind and solar carve-outs are maintained, with additional generic clean energy available from either solar or onshore wind, whichever is most economic (considering both their clean energy value and capacity value at the prevailing clean and capacity prices). The PJM-wide demand curve for clean energy is implemented similarly to the one developed for Maryland and applies only to states that have already adopted renewable portfolio standards.

Table 5 provides a summary of prices, costs, and quantities procured across study years and alternative market design scenarios.

TABLE 5: SUMMARY OF ECONOMIC RESULTS ACROSS SCENARIOS

		2025						2030					
		Status Quo	No-MOPR RPM	Best Case FRR	IMM FRR	MD Only ICCM	PJM-Wide ICCM	Status Quo	No-MOPR RPM	Best Case FRR	IMM FRR	MD Only ICCM	PJM-Wide ICCM
Capacity													
Cleared UCAP MW	*(UCAP MW)*	14,042	14,162	13,740	13,740	13,740	14,279	13,943	14,037	13,472	13,472	13,472	14,114
Uncleared MD MOPR Resources	*(UCAP MW)*	1,210	0	0	0	0	0	1,669	0	0	0	0	0
Average MD Capacity Price	*($/MW-day)*	$189	$155	$169	$225	$156	$147	$148	$124	$138	$241	$115	$117
Capacity Costs	*($ Millions/yr)*	$968	$801	$849	$1,128	$783	$765	$752	$633	$678	$1,185	$565	$603
Contracts and Clean Energy													
Renewable Energy Supply	*(% of Load)*	40%	40%	40%	40%	43%	42%	50%	50%	50%	50%	62%	56%
Clean Energy Supply	*(% of Load)*	65%	65%	65%	65%	68%	66%	75%	75%	75%	75%	87%	81%
Contracts and Clean Energy Costs	*($ Millions/yr)*	$185	$116	$114	$53	$162	$138	$275	$200	$195	$112	$272	$240
Total Maryland Customer Costs	***($ Millions/yr)***	**$1,153**	**$917**	**$963**	**$1,181**	**$945**	**$903**	**$1,027**	**$833**	**$873**	**$1,297**	**$837**	**$843**
Costs Above (Below) Status Quo	*($ Millions/yr)*	*n/a*	*($236)*	*($190)*	*$28*	*($208)*	*($250)*	*n/a*	*($194)*	*($154)*	*$270*	*($190)*	*($184)*

Notes: Monetary values reported in nominal dollars.

AUTHORS

Kathleen Spees is a Principal and Board Member at Brattle with expertise in advising clients on addressing the challenges associated with system-wide decarbonization. Dr. Spees has worked extensively in jurisdictions in both the United States and worldwide on approaches to enable and integrate clean energy technologies. She has led modeling teams conducting detailed evaluations and studies of the power markets of the future under 50-100% clean electricity in New England, Ontario, and New York.

Travis Carless is an Associate specializing in electricity sector topics such as low-carbon generation, nuclear power, climate policy analysis, and resource planning. Prior to joining Brattle, Dr. Carless served as a President's Postdoctoral Fellow at Carnegie Mellon University and a Stanton Nuclear Security Fellow at the RAND Corporation. He received a National Science Foundation Graduate Research Fellowship for his research, which focused on assessing the environmental competitiveness of small modular reactors and risk and regulatory considerations for small modular reactor emergency planning zones.

Walter Graf is a Senior Associate at The Brattle Group specializing in electricity market analysis and wholesale market design. Dr. Graf has worked on several projects related to transforming electricity markets, quantifying the value of additional carbon-free resources, improving efficiency of renewable resource integration, and designing mechanisms to incentivize clean energy development. Dr. Graf is a member of the Brattle design team that developed a proposal for a new centrally organized forward clean energy market that would foster competition and transparency in the procurement of clean energy.

Samuel Newell is a Principal and the leader of The Brattle Group's Electricity Practice. He has 22 years of experience supporting clients in wholesale market design, generation asset valuation, resource planning, and transmission planning. Much of his work addresses the industry's transition to clean energy. He frequently provides testimony and expert reports to Independent System Operators, the Federal Energy Regulatory Commission, state regulatory commissions, and the American Arbitration Association.

Document Content(s)

ATTACHMENT B

Curriculum Vitae of Dr. Kathleen Spees

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Dr. Kathleen Spees is a Principal at The Brattle Group with expertise in wholesale electricity and environmental policy design and analysis. Her work for market operators, regulators, regulated utilities, and market participants focuses on:

- Wholesale Power Market Reform
- Capacity Market Design
- Wholesale Energy and Ancillary Service Market Design
- Carbon and Environmental Policy
- Generation and Transmission Asset Valuation
- Analysis of Emerging Technologies and Specialized Products

Dr. Spees has worked in more than a dozen international jurisdictions supporting the design and enhancement of environmental policies and wholesale power markets. Her clients include electricity system operators in PJM, Midcontinent ISO, New England, Ontario, New York, Alberta, Texas, Italy, and Australia. Electricity market design assignments involve ensuring adequacy of capacity and energy market investment incentives to achieve reliability objectives at least cost; designing carbon and clean energy policies that effectively interact with wholesale electricity markets; enhancing operational reliability and efficiency through energy market, scarcity pricing, and ancillary service market improvements; effectively integrating intermittent renewables, storage, demand response, and other emerging technologies; evaluating benefits and costs of industry reform initiatives; and enhancing efficiency at market interties.

For system operators and regulators, Dr. Spees provides expert support through stakeholder forums, independent public reports, and testimony in regulatory proceedings. For utilities and market participants, her assignments support business strategy, investment decisions, asset transactions, contract negotiation, regulatory proceedings, and litigation. Dr. Spees has developed and applied a wide range of analytical and modeling tools to inform these policy, market design, and business decisions.

Dr. Spees earned her PhD in Engineering and Public Policy within the Carnegie Mellon Electricity Industry Center in 2008 and her MS in Electrical and Computer Engineering from Carnegie Mellon University in 2007. She earned her BS in Physics and Mechanical Engineering from Iowa State University in 2005.

Publications posted at: http://www.brattle.com/experts/kathleen-spees

REPRESENTATIVE EXPERIENCE

WHOLESALE POWER MARKET REFORM

- **Ontario Market Renewal Benefits Case.** For the Ontario Independent Electricity System Operator (IESO), developed an analysis evaluating the benefits and implementation costs associated with fundamental reforms to wholesale power markets, including implementing nodal pricing, a day-ahead energy market, enhanced intra-day unit commitment, operability reforms, an enhanced intertie design, and a capacity market. Analysis included: (a) market visioning sessions with IESO staff and stakeholders to identify future market design requirements; (b) identify primary drivers and quantify system efficiency benefits; (c) review lessons learned from other markets' reforms to identify opportunities and reform risks; (d) conduct a bottom-up analysis of implementation costs for replacing market systems; and (e) evaluate interactions with existing supply contracts.

- **MISO Market Development Vision.** For the Midcontinent Independent System Operator (MISO), worked with staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2-5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities for improving MISO's electricity market; and proposing criteria for prioritizing initiatives within and across Focus Areas.
- **Australia NEM Electricity Market Vision for Enabling Innovation and Clean Energy.** On behalf of the Australian Energy Market Operator reviewed electricity market design options for the future of the NEM. Evaluated opportunities for relying on markets, innovation, and new technologies to address a range of challenges in the context of significant increases in customer costs, high gas prices, large clean energy penetration, coal retirements, uncertain carbon policies, and emerging reliability and security concerns.
- **Thailand Power Market Reform.** Supported market design options and recommendations for potential power market reforms in Thailand, including the introduction of forward, day-ahead, and real-time energy markets, as well as the potential introduction of a bilateral or centralized capacity market. Examined interactions with retail rates, existing contracts, and self-supply arrangements.
- **Power Market Reform to Accommodate Decarbonization and Clean Energy Policies.** For the system operator in a jurisdiction pursuing significant clean energy and decarbonization policies, assisted in evaluating market design alternatives. Estimated energy price, customer cost, and reliability implications under alternative energy, ancillary service, and capacity market design scenarios. Quantified implications of key uncertainties such as intermittent resource penetration levels and impacts of interties with external regions. Provided research and comparative analysis of design alternatives and lessons learned from other jurisdictions.
- **Western Australia Power Market Reform Options.** For EnerNOC, developed a whitepaper describing high-level market reform options in the face of escalating customer costs in Western Australia. Described the drivers of capacity payment costs in comparison to other major cost driver. Identified high-level options for pursuing capacity and energy-only market design reforms, comparing advantages and disadvantages.
- **Russian Capacity and Natural Gas Market Liberalization.** On behalf of a market participant, conducted an assessment of market design, regulatory uncertainty, and liberalization success. Focus was on the efficiency of market design rules in the newly introduced system of capacity

contracts combined with capacity payments, as well as on the impacts of gas price liberalization delays.

- **PJM Review of International Energy-Only, Capacity Market, and Capacity Payment Mechanisms.** For PJM Interconnection, conducted a review of energy-only markets, capacity payment systems, and capacity markets on behalf of PJM market operator. Reviewed reliability, volatility, and overall investment outcomes related to details of market designs in bilateral, centralized, and forward commitment markets.
- **Options for Reconciling Regulated Planning and Wholesale Power Markets in in MISO.** For NRG, developed a whitepaper assessing reliability and economic implications of current capacity market and integrated planning approaches, and the challenges in accommodating retail access and integrated planning within the same market region. Recommended options for enhancing the MISO capacity market and regulated entities' approaches to planning.
- **Review of California Planning and Market Mechanisms for Resource Adequacy.** For Calpine, evaluated interactions and implications of California's policy, planning, and market mechanisms affecting resource adequacy. Recommended improvements to reconcile inconsistencies and enhance efficiencies in regulated long-term procurements, short term local resource adequacy construct, and CAISO backstop mechanisms.

CAPACITY MARKET DESIGN

- **PJM Review of Capacity Market Design and Demand Curve Parameters: 2011, 2014, and 2018.** For PJM Interconnection, conducted independent periodic reviews of PJM's Reliability Pricing Model. Analyzed market functioning for resource adequacy including uncertainty and volatility of prices, net cost of new entry parameters, impacts of administrative parameters and regulatory uncertainties, locational mechanisms, demand curve shape, incremental auction procedures, and other market mechanisms. Developed a probabilistic simulation model evaluating the price volatility and reliability implications of alternative demand curve shapes and recommended a revised demand curve shape. Provided expert support to stakeholder proceedings, testimony submitted before the Federal Energy Regulatory Commission, and before the Maryland Public Service Commission.
- **MISO Resource Adequacy Construct.** For MISO, conducted a review of MISO's resource adequacy construct. Subsequent assistance to MISO in enhancing the market design for resource adequacy related to market redesign, capacity market seams, and accommodation of both regulated and restructured states. Provided background presentations to stakeholders on the capacity market design provisions of NYISO, PJM, CAISO, and ISO-NE.
- **Alberta Energy-Only Market Review for Long-Term Sustainability: 2011 and 2013 Update.** For AESO, conducted a review of the ability of the energy-only market to attract and retain sufficient levels of capacity for long-term resource adequacy. Evaluation of the outlook for revenue sufficiency under forecasted carbon, gas, and electric prices, potential impact of environmentally-driven retirements, potential federal coal retirement mandate, and provincial energy policies.

- **Economic Implications of Resource Adequacy Requirements.** For the U.S. Federal Energy Regulatory Commission, reviewed economic and reliability implications of resource adequacy requirements based on traditional reliability criteria as well as alternative standards based on economic criteria. Evaluated total system costs, customer costs, supplier net revenues, and demand response implications under a range of reserve margins as well as under different energy-only and capacity market designs.
- **Winter Resource Adequacy and Reliability.** For an RTO, analyzed the risk of winter reliability and resource adequacy shortages. Examined the drivers of winter reliability concerns including unavailability of specific resource types, winter fuel supply shortages, and weather-driven outages. Developed a range of potential reforms for addressing identified concerns.
- **Alberta Capacity Market Design.** Supported the development of a capacity market design in Alberta. Provided expert support to public working groups and AESO staff to review analytical questions, develop and evaluate design alternatives, and draft design documents. Supported on all aspects of market design including establishing reliability requirements, developing demand curve parameters, evaluating seasonal capacity resources, setting capacity ratings, product definition and obligations, and penalty mechanisms.
- **European Market Flexibility and Capacity Auction Design.** For European client, developed a market-based design for meeting flexible and traditional capacity needs in the context of high levels of intermittent resource penetration, degraded energy and ancillary pricing signals, and ongoing electricity market reforms. Engaged in meetings with industry and European Commission staff to develop and refine design options. Developed a model simulating market clearing results in a two-product auction and projecting prices over time.
- **Italian Capacity Market Design.** For Italy's transmission system operator Terna, supported development of a locational capacity market design and locational capacity demand curves based on simulation modeling on the value of capacity to customers.
- **Capacity Auction Design for Western Australia**. For Western Australia's Public Utility Office, drafted a whitepaper and advised on the design of its new capacity auction mechanism.
- **IESO Capacity Auction Design.** Provided expert support to IESO staff in support of a new capacity auction design. Provided detailed memos describing options, tradeoffs, and lessons learned on every aspect of capacity auction design. Supported stakeholder engagement, conducted analysis of design alternatives, and developed design proposals.
- **PJM Seasonal Capacity Market Design.** For the Natural Resources Defense Council, provided testimony and economic analysis in support of improving the capacity market design to better accommodate seasonal capacity resources.
- **ISO New England Capacity Demand Curve**. For ISO New England, worked with RTO staff and stakeholders to develop a selection of capacity demand curves and evaluate them for their efficiency and reliability performance. Began with a review of lessons learned from other market and an assessment of different potential design objectives. Developed and implemented a statistical simulation model to evaluate probabilistic reliability, price, and reserve margin outcomes in a locational capacity market context under different candidate demand curve

shapes. Submitted Testimony before the Federal Energy Regulatory Commission supporting a proposed system-wide demand curve, with ongoing support to develop locational demand curves for individual capacity zones.

- **MISO-PJM Capacity Market Seams Analysis.** For MISO, evaluated barriers to capacity trade with neighboring capacity markets, including mechanisms for assigning and transferring firm transmission rights and cross-border must-offer requirements. Evaluated economic impacts of addressing the barriers and identified design alternatives for enabling capacity trade.
- **MISO Competitive Retail Choice Solution.** For MISO, evaluated design alternatives for accommodating the differing needs of states relying on competitive retail choice and integrated resource planning. Conducted probabilistic simulations of likely market results under alternative market designs and demand curves. Provided expert support in stakeholder forums and submitted expert testimony before the Federal Energy Regulatory Commission.
- **Capacity Market Manipulation.** For a market participant, supported economic and policy analysis of an alleged instance of capacity market withholding.
- **Demand Curve and Net Cost of New Entry Review.** For an RTO, provided a high-level conceptual review of its approach to establishing demand curve and net cost of new entry parameters. Identified potential reliability and economic efficiency concerns, and recommended enhancements.
- **Western Australia Reserve Capacity Mechanism and Transition Mechanism**. For EnerNOC, authored two public reports related to the energy market reforms in Western Australia. The first report evaluated the characteristics of the Western Australia Reserve Capacity Mechanism in comparison with international best practices and made recommendations for improvements, whether pursuing a capacity market or energy-only market design. The second report evaluated and recommended changes to the regulator's proposed mechanism for transitioning to its long-term capacity market design.
- **Cost of New Entry Study to Determine PJM Auction Parameters: 2011 and 2014.** For PJM Interconnection, partnered with engineering, procurement, and construction firm to develop bottom-up cost estimates for building new gas combined cycles and combustion turbines. Affidavit before the Federal Energy Regulatory Commission and participation in settlement discussions on the same.

WHOLESALE ENERGY AND ANCILLARY SERVICE MARKET DESIGN

- **Greece Energy and Ancillary Service Market Reform.** For the Hellenic Association of Independent Power Producers, provided expert advice and a report on how to reform wholesale power markets to conform with policy mandates and meet system flexibility needs. Analyzed energy and ancillary market pricing and rules to identify opportunities to enhance efficiency, improve participation of emerging resources, achieve market coupling, and better integrate intermittent resources. Proposed high-level design recommendations for implementing forward, day-ahead, intraday, and balancing markets consistent with European Target Model requirements. Developed detailed design recommendations for near-term and long term enhancements to market operations, pricing, dispatch, and settlements. Provided expert support in meetings with European Commission staff.

- **Alberta Energy and Ancillary Service Market Enhancements.** Supported the development of market design enhancements to better support flexibility needs and align with capacity market implementation. Developed design proposals and evaluated alternatives for immediate and long-term reforms including monitoring and mitigation, enhanced administrative scarcity pricing, ancillary service co-optimization, day-ahead markets,
- **SPP Ramp Product Proposal.** For Golden Spread Electric Cooperative, developed recommendations for the design and implementation of a ramping product to most efficiently and cost-effectively manage intermittency needs. Reviewed opportunities to determine the most appropriate quantity of resources, forward product timeframe, price formation, and interactions with existing pricing and commitment procedures.
- **ERCOT Energy Market Design and Investment Incentives Review.** For the Electric Reliability Council of Texas (ERCOT), conducted a study to: (a) characterize the factors influencing generation investment decisions; (b) evaluate the energy market's ability to support investment and resource adequacy at the target level; (c) examine efficiency of pricing and incentives for energy and ancillary services, focusing on scarcity events; and (d) evaluate options to enhance long-term resource adequacy while maintaining market efficiency. Performed forward-looking simulation analyses of prices, investment costs, and reliability. Interviewed a broad spectrum of stakeholders; worked with ERCOT staff to understand the relevant aspects of their planning process, operations, and market data. Supported ongoing proceedings with stakeholders and before the Public Utility Commission of Texas.
- **Scarcity and Surplus Event Pricing.** For an RTO, examined the efficiency and reliability implications of its pricing mechanisms during scarcity and surplus events, and evaluated potential market reforms. Options reviewed included adjusting the price cap consistent with the value of lost load, adjusting supplier offer caps, imposing administrative scarcity prices at varying levels of emergency events, ancillary service market pricing interactions, and reducing the price floor below zero.
- **MISO Wind Curtailment Interactions with Energy Market Pricing and Transmission Interconnection Processes.** For MISO, evaluated the efficiency and equity implications of wind curtailment prioritization mechanisms and options for addressing stakeholder concerns, including interconnection agreement types, energy and capacity injection rights, ARR/FTR allocation mechanisms, energy market offers, and market participant hedging needs.
- **Survey of Energy Market Seams.** For the Alberta Electric System Operator (AESO), assessed the implications of energy market seams inefficiencies between power markets in Canada, the U.S., and Europe for the Alberta Electric System Operator. Evaluation of options for improving seams based on other markets' experiences with inter-regional transmission upgrades, energy market scheduling and dispatch, transmission rights models, and resource adequacy.
- **New England Fuel Security Market Design.** For NextEra, developed design proposals for using market-based mechanisms to meet regional fuel security needs including through a fuel security

reserve product that would enhance pricing and operations for fuel security in the energy and ancillary service markets, and options for a long-term solution through forward auctions for fuel security.

- **Reliability Auctions for the NEM.** For the Australian Electricity Market Operator conducted an international review of the range of approaches to supporting reliability and system security through competitive auctions. Focused on product definition including, various aspects of reliability and system security, auctions focused on enabling non-traditional resource types, options ranging from strategic reserve models to partial needs procurements to capacity markets, and potential for impacts on energy-only market pricing and performance.
- **ERCOT Operating Reserves Demand Curve and Economically Optimal Reserve Margin 2014 and 2018.** For the Public Utility Commission of Texas and ERCOT, co-authored a report estimating the economically-optimal reserve margin. Compared to various reliability-based reserve margins, and evaluated the cost and uncertainty of energy-only and a potential capacity market in ERCOT. Conducted the study in collaboration with Astrape Consulting to construct a series of economic and reliability modeling simulations that account for uncertain weather patterns, generation and transmission outages, and multi-year load forecasting errors. The simulations also incorporate detailed representation of the Texas power market, including intermittent wind and solar generation, operating reserves, different types of demand response, the full range of emergency procedures (such as operating reserve deletion), scarcity pricing provisions, and load-shed events.
- **Southern Company Independent Auction Monitor.** For Southern Company, developed auction monitoring capability and protocol development for monitoring hourly and daily auctions. Supported functions included daily and annual audits of internal company processes and data inputs related to load forecasting, purchases and sales, and outage declarations. Analyzed company data to develop monitoring protocols and automated tools. Coordinated implementation of data collection and aggregation system required for market oversight and for detailed internal company data audits.

CARBON AND ENVIRONMENTAL POLICY

- **Integrating Markets and Public Policy in New England.** For a coalition of stakeholders, engaged in a collaborative effort to develop market-based approaches for accommodating and achieving state decarbonization objectives. Developed and refined design proposals including carbon pricing and market-based clean energy procurements, while identifying options for reducing regulatory uncertainties, avoiding cross subsidies across states, and mitigating customer cost impacts. Evaluated options for improving interactions with existing energy, capacity, renewable energy credit, and carbon markets. Conducted modeling of price, cost, and emissions outcomes under a range of designs. Engaged in an iterative process to develop, present, and refine design proposals based on input from a broad array of stakeholders. Provided expert support in outreach to state policymakers and industry groups.

- **Ontario Market Evolution to Support a 90% Clean Energy System and Increasing Distributed Resources.** For the IESO, supported the activities of the non-emitting stakeholder committee to model market reforms necessary to fully enable the 90% clean energy fleet. Supported stakeholder workshops to identify potential futures with many more distributed resources, a range of technology costs, and a variety of market designs. Conducted modeling analysis to analyze market outcomes including cost, reliability, resource curtailment, and resource revenues.
- **National Carbon Policy Design and Interactions with Power Markets.** For an international regulator, analyzed a range of options for the design of a carbon policy for the electricity sector, considering impacts on the wholesale electricity market and interactions with other sectors. Analyzed a range of alternatives for intensity-based and cap-and-trade based approaches, alternative allocations methods, and interactions with renewables standards. Developed two detailed design alternatives within the specified policy constraints.
- **Review of International Carbon Mechanisms.** For an RTO, conducted a survey of international carbon pricing, cap-and-trade, and rate-based mechanisms, and detailed review of design elements of the mechanisms implemented in Europe, California, Alberta, and the Regional Greenhouse Gas Initiative. Evaluated a range of alternatives for implementing the Clean Power Plan across states while effectively integrating with wholesale markets.
- **New York ISO Carbon Pricing.** For the New York ISO, examined economic implications of a possible carbon pricing proposal within the wholesale electricity market. Developed a whitepaper evaluating interactions with state environmental policies, wholesale power markets, intertie pricing, capacity market, and transmission planning. Estimated energy price and customer cost impacts.
- **Carbon Allowance Allocations Alternatives.** For the National Resources Defense Council, developed a whitepaper examining the advantages and disadvantages of auction-based, customer-based, and generator-based approaches to allocating carbon allowances. Developed recommendations for avoiding the introduction of inefficient investment, retirement, and operational incentives under each type of design, and for mitigating customer cost impacts.
- **Power Market Impacts of Clean Power Plan Alternatives.** Conducted a modeling assessment of price, cost, and emissions implications of different rate-based, subcategory rate-based, and mass-based implementation of the Clean Power Plan in Texas. Estimated energy, emission reduction credit, and carbon prices under each scenario, and net revenue and operating implications for several types of generating plants.
- **Review of Hydropower Industry Implications under Clean Air Act 111(d).** For the National Hydropower Association, provided members review of the implications for new and existing hydropower resources of proposed EPA Clean Power Plan under Clean Air Act Section 111(d). Analyzed impacts under a variety of potential revisions to the proposed rule, different potential state compliance options, differing plan regulatory statuses, mass-based vs. rate-based compliance, regulated planning vs. market-based compliance, and cooperative vs. stand-alone compliance.

- **Enabling Canadian Imports for U.S. Clean Energy Policies.** For a coalition of Canadian electricity producers and policymakers, reviewed a range of options for U.S. states to pursue clean energy policies and the Clean Power Plan while enabling contributions from clean energy imports.
- **Clean Power Plan Regulatory and Stakeholder Support.** For a cooperative entity, provided support in developing internal and external positioning associated with the Clean Power Plan. Analyzed state-wide emissions targets and compliance alternatives. Supported messaging and stakeholder engagement at the state and federal levels. Submitted testimony before the Environmental Protection Agency.
- **State Compliance Strategy under the Clean Power Plan.** For a regulated utility, evaluated options and feasibility of meeting state standards under 111(d) rate standards under a number of compliance scenarios. Developed an hourly dispatch model covering backcast and forecast years through the interim and final compliance timelines, accounting for impacts of load growth, renewables growth, coal-to-gas redispatch, coal minimum dispatch constraints, planned retirements, new generation development, and export commitments. Estimated the ability to meet the standard under various compliance strategies.
- **New Gas Combined Cycle Plants Under the Clean Power Plan.** For the National Resources Defense Council, developed a whitepaper evaluating the economic implications of Clean Power Plan implementation plans that do or do not cover gas combined cycle plants on a level basis with other fossil-emitting plants. Conducted simulation analyses comparing the economic and emissions implications of alternative approaches.
- **MISO Coal Retrofit Supply Chain Analysis.** For the MISO, analyzed the fleet-wide requirements for retrofitting plants to upgrade for the Mercury and Air Toxics Standard. Reviewed the upstream engineering services, procurement, and construction supply chain to evaluate the ability to upgrade the fleet within the available time window. Analyzed the potential for operational and reliability concerns from simultaneous planned outages needed to support fleet-wide retrofit requirements in the MISO footprint.
- **Impact of Environmental Policies on Coal Plant Retirement.** For a PJM market participant, conducted a zone-level analysis of PJM market prices and used unit-level data to conduct a virtual dispatch of coal units under a series of long-term capacity, fuel, and carbon price scenarios. Modeled retirement decisions of plants by PJM zone and the effect of the carbon price on the location and aggregate size of these retirement decisions.

Generation and Transmission Asset Valuation

- **Generation and Transmission Asset Valuations (Multiple Clients).** For multiple clients, top-line operating cost and revenues estimation for generation and transmission assets in PJM, ISO-NE, MISO, SPP, and ERCOT; experience with a range of asset types including gas CCs, gas CTs, coal, wind, waste-to-energy, cogeneration, and HVDC lines. Evaluation exercises include forecasting market prices and net revenues from energy, capacity, ancillary service, and (if applicable) renewable energy credit markets. Valuations account for the operational impacts and economic value of existing power purchase agreements and other hedges. Clients typically require qualitative and quantitative analysis of regulatory risks under a range of operational and market scenarios. Valuation efforts often conducted in the context of due diligence for transactions, business decisions, and contract negotiations.

- **Executive Education and Investment Opportunities Surveys (Multiple Clients).** For multiple clients, provided executive education and detailed survey material to support investments in new markets and strategic decision-making. Educational efforts provided over a range of levels including high-level executive sessions, all-day workshop sessions, and detailed support for analytical teams. Examples of subject matter include: (a) cross-market surveys comparing investment attractiveness in many dimensions based on market fundamentals, regulatory structure, and contracting opportunities; and (b) single-market deep-dive educational sessions on capacity, energy, ancillary service, and financial/hedging product functioning and market performance.

- **In-House Fundamentals Capability Development (Multiple Clients).** For multiple clients, supported the development of in-house capability for market fundamentals analysis. Typically needed in the context of new entrants to a market or system operators expanding the scope of their internal analytical capabilities. Scope of support has included: (a) initial education, backup support, and advisory support for fundamentals teams entering a new market; (b) development and transfer of new purpose-built modeling tools such as capacity market models; and (c) external peer review or independent assessment functions.

- **Asset or Fleet Valuation in Support of Litigation and Arbitration Proceedings (Multiple Clients).** In litigation and arbitration contexts, provided estimates of economic damages or asset/fleet value estimates that would have applied at the time of a particular business decision. Supported expert testimony, litigation workpapers, and assessment of opposing experts' analysis.

- **Economic Analysis of Plant Retrofit and Fuel Contracting Decisions (Multiple Clients).** Supported plant operational and investment decisions for enhancing the value of particular assets, including contexts such as: (a) retrofitting plants from oil to gas generation; (b) retrofitting single-cycle to combined cycle with different capacities for duct firing; (c) enhancing ancillary service capability; and (d) and contracting for firm gas capability. Evaluated operational, cost, and revenue impacts of alternatives and compared to present investment costs.

- **Financial Implications of Regulatory, Policy, and Market Design Changes (Multiple Clients).** Conducted analyses of risks and opportunities associated with regulatory, policy, and market design changes. Examples include an analysis of potential Trump administration policies, implications of potential clean energy and carbon policies, and assessing private risks from changes to ancillary service market rules.

Emerging Technologies and Specialized Products

- **RTO Business Models Analysis for Enabling Customer-Side Disruption and the Clean Energy Future.** For a system operator, engaged in an executive strategy analysis to evaluate a range of electricity sector business models under a future with high penetrations of distributed resources and decarbonization. Developed detailed scenario descriptions of the business models envisioned considering different roles and scope of services provided by the RTO, distribution companies, load serving entities, and third-party aggregators. Created an interactive tool for mapping financial flows and energy flows at all points in the electricity value chain under each business model considered, and drew implications for value proposition of each segment of the market.

- **Enabling Market Participation from Non-Emitting and Emerging Technologies.** For an Ontario stakeholder group, provided expert support to identify market design enhancements to enable and integrate non-emitting and emerging technologies. Examined participation barriers and design enhancements to unlock full value of resources for supporting energy, flexibility, capacity, and other value streams to the province.
- **International Review of Demand Response Integration into Wholesale Electricity Markets.** For the Australian Energy Market Commission, authored a report describing the range of approaches and market experience integrated demand response into wholesale energy, ancillary service, and capacity markets. Provided detailed discussion of approaches in Singapore, Alberta, ERCOT, PJM, ISO New England, and Ontario. Summarized lessons learned regarding demand response business models, efficient wholesale pricing signals, and interactions with retail markets.
- **Oncor Value of Distributed Storage**. For Oncor Electric Delivery Company, conducted a benefit-cost analysis of adding varying levels of distributed storage into the ERCOT market. Value streams considered including market values such as energy and ancillary services, as well as regulated system values including deferred transmission and distribution costs, and avoiding distribution outages. Evaluated value from the perspectives of customers, a merchant storage developer, and society as a whole, as well as evaluating impacts on incumbent suppliers.
- **Oncor Distributed Storage Business Models to Supply Customer, Distribution System, and Wholesale Value Streams**. For Oncor Electric Delivery Company, conducted a benefit-cost analysis of adding varying levels of distributed storage into the Texas market. Recommended policy changes to enable storage under a range of business models (merchant, utility-owned, customer-owned, and third-party owned), and to allow for the development of resources that could provide multiple value streams. Value streams considered including market values such as energy and ancillary services, distribution-system values including deferred transmission and distribution costs, and customer value streams including avoiding distribution outages. Evaluated value from the perspectives of customers, a merchant storage developer, and society as a whole, as well as evaluating impacts on incumbent suppliers.
- **Risk and Financial Analysis of PJM Capacity Performance Product.** For a market participant, conducted a probabilistic assessment of the expected value, upside, and downside risks (both market-wide and private) associated with PJM's capacity performance product. Evaluated the likely frequency of scarcity events on average and as concentrated in particular years to estimate the expected value of bonus payments if operating as an energy-only asset, and the net potential bonus/penalty if operating as a capacity performance resource. Estimated risk-neutral and risk-averse capacity price offer levels; characterized the magnitude of risk exposure of poor asset performance coincided with system scarcity events.

- **Demand Response Auction Design.** For a system operator, assisted in the high-level and detailed designs of a demand response auction. Supported market rule development, auction clearing optimization specification, and quality control testing of auction clearing engine.
- **Hedging Products for Wind.** For a hedge fund, provided analytical support for the development of a hedging product for wind developers. Evaluated the risk exposure based on day-ahead and real-time participation, locational price differentials, profile and curtailment risks, and discrepancies with exchange-traded hedging products.
- **Tariff Design for Merchant Transmission Upgrades.** For a transmission developer, evaluated tariff design options for capturing market value of wind and transmission for a market participant proposing a large HVDC upgrade to enable wind developments.
- **Magnitude and Potential Impact of "Missing Efficiency" in PJM.** For the Natural Resources Defense Council, analyzed the potential magnitude of energy efficiency programs in PJM that are not accounted for on either demand side (through load forecast adjustments) or on the supply side (in the capacity market). Estimated potential energy and capacity market customer cost impacts in both the short-run and long-run if adjusting the load forecast to account for the missing efficiency.
- **Financial Transmission Right and Virtual Bidding Market Manipulation Litigation for PJM.** For PJM Interconnection, analyzed financial transmission rights, energy market, and virtual trading data for expert testimony regarding market manipulation behavior.
- **Wind and Storage.** For a developer of potential storage assets, simulation analysis modeling combined effects of gas dispatch, wind variability, load variability, and minimum generation conditions to determine the value of electric storage under various levels of wind penetration. Conducted portfolio analysis to determine the optimal level of storage on a systems level to minimize cost as a function of wind penetration levels.
- **Market Reforms to Meet Emerging Flexibility Needs.** For the Natural Resources Defense Council, authored a report on the electricity market reforms needed in the context of declining needs for baseload resources, increasing levels of intermittent supply, and increasing needs for flexible resources.

REPRESENTATIVE PUBLICATIONS

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Spees, Kathleen, Yingxia Yang, and Yeray Perez. *Energy and Ancillary Services Market Reforms in Greece: A Path to Enhancing Flexibility and Adopting the European Target Model.* Prepared for the Hellenic Association of Independent Power Producers (HAIPP). May 2017.

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Newell, Samuel A., Kathleen Spees, and David Luke Oates. Testimony on Behalf of Midcontinent Independent System Operator (MISO) regarding the Competitive Retail Solution. Docket No. ER17-284-000. November 1, 2016.

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Spees, Kathleen, Samuel A. Newell, David Luke Oates and James Mashal. "Clean Power Plan in Texas: Implications for Renewables and the Electricity Market," Presented at the 2016 Renewable Energy Law Conference. February 9, 2016.

Pfeifenberger, Johannes P., Judy Chang, Kathleen Spees, and Matthew K. Davis. "Impacts of Distributed Storage on Electricity Markets, Utility Operations, and Customers," 2015 MIT Energy Initiative Associate Member Symposium. May 1, 2015.

Chang, Judy, Johannes P. Pfeifenberger, Kathleen Spees, and Matthew K. Davis. "The Value of Distributed Electrical Energy Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments," Energy Storage Policy Forum 2015, Washington, D.C. January 29, 2015.

Spees, Kathleen. "EPA's Clean Power Plan: Potential Impacts on Asset Values," Infocast 7th Annual Projects & Money Summit 2015. January 13, 2015.

Chang, Judy, Johannes P. Pfeifenberger, Kathleen Spees, and Matthew K. Davis. "The Value of Distributed Electrical Energy Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments," UBS Investment Research Webinar. December 5, 2014.

Spees, Kathleen and Judy Chang. "Evaluating Cooperation Opportunities under CAA 111(d)," Presented to the Eastern Interconnection States' Planning Council. October 2, 2015.

Spees, Kathleen. "Implications of EPA's Clean Power Plan under Clean Air Act Section 111(d)," Presented to the Department of Engineering and Public Policy at Carnegie Mellon University. September 18, 2015.

Spees, Kathleen, Samuel A. Newell, and Johannes P. Pfeifenberger. "ERCOT's Optimal Reserve Margin: As Estimated for the Public Utility Commission of Texas and the Electric Reliability Council of Texas," presented to the 2014 Texas Industrial Energy Consumers Annual Meeting. July 15, 2014.

Pfeifenberger, Johannes P., Samuel A. Newell, and Kathleen Spees. "Energy and Capacity Markets: Tradeoffs in Reliability, Costs, and Risks," presented at the Harvard Electricity Policy Group Seventy-Fourth Plenary Session. February 27, 2014.

Spees, Kathleen, Johannes P. Pfeifenberger, and Samuel A. Newell. "ERCOT's Optimal Reserve Margin," presented to UBS Investment Research investor conference call. February 19, 2014.

Spees, Kathleen. "Capacity Markets: Lessons Learned from the First Decade," presented to EUCI 10th Annual Capacity Markets Conference. November 7, 2013.

Pfeifenberger, Johannes P, and Kathleen Spees. "Characteristics of Successful Capacity Markets," presented at the APEx Conference 2013, New York. NY. October 31, 2013.

Spees, Kathleen and Johannes Pfeifenberger. "Outlook on Fundamentals in PJM's Energy and Capacity Markets," presented at the 12th Annual Power and Utility Conference, Hosted by Goldman Sachs.

August 8, 2013.

Newell, Samuel A., and Kathleen Spees. "Get Ready for Much Spikier Energy Prices: The Under-Appreciated Market Impacts of Displacing Generation with Demand Response," presented at the Cadwalader Energy Investor Conference. February 7, 2013.

Spees, Kathleen and Johannes P. Pfeifenberger. "PJM Reliability Pricing Model: 2016/17 Planning Period Parameters Update," presented to Barclays North American Utilities Investor Call. February 4, 2013.

Spees, Kathleen and Johannes P. Pfeifenberger. "Seams Inefficiencies: Problems and Solutions at Energy Market Borders," presented at the EUCI Canadian Transmission Summit. July 17, 2012.

Spees, Kathleen. "New U.S. Emission Regulations: Electric Industry Impacts," presented at the U.S. Energy 24th Annual Energy Conference. May 11, 2012.

Spees, Kathleen. "Market Design from a Practitioner's Viewpoint: Wholesale Electric Market Design for Resource Adequacy," presented at Lawrence University Economics Colloquium. April 23, 2012.

Spees, Kathleen. "Options for Extending Forward certainty in Capacity Markets." Presented at the EUCI Conference on Capacity Markets: Achieving Market Price Equilibrium. November 9, 2011.

Spees, Kathleen, and Pfeifenberger, Johannes P. "Resource Adequacy: Current Issues in North American Power Markets." Presented at the Alberta Power Summit. November 19, 2011.

Spees, Kathleen and Samuel Newell. "Capacity Market Designs: Focus on CAISO, NYISO, PJM, and ISO-NE," Presented to the Midwest ISO Supply Adequacy Working Group. July 19, 2010.

Pfeifenberger, Johannes P., and Kathleen Spees. "Best Practices in Resource Adequacy," presented at the PJM Long Term Capacity Issues Symposium. January 27, 2010.

Chang, Judy, Kathleen Spees, and Jurgen Weiss. "Using Storage to Capture Renewables: Does Size Matter?" working paper presented at the 15th Annual POWER Research Conference. University of California Energy Institute's Center for the Study of Energy Markets. March 18, 2010.

ATTACHMENT C

Curriculum Vitae of Dr. Samuel A. Newell

SAMUEL A. NEWELL

Principal

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Dr. Samuel Newell leads Brattle's Electricity Group. He has 23 years of experience supporting clients in wholesale market design, generation asset valuation, resource planning, and transmission planning. Much of his work addresses the industry's transition to clean energy. He frequently provides testimony and expert reports to Independent System Operators (ISOs), the Federal Energy Regulatory Commission (FERC), state regulatory commissions, and the American Arbitration Association.

Dr. Newell earned a Ph.D. in Technology Management & Policy from the Massachusetts Institute of Technology, an M.S. in Materials Science & Engineering from Stanford University, and a B.A. in Chemistry & Physics from Harvard College.

Prior to joining The Brattle Group in 2004, Dr. Newell was the Director of the Transmission Service at Cambridge Energy Research Associates. Before that, he was a Manager at A.T. Kearney.

AREAS OF EXPERTISE

- Electricity Market Design and Analysis
- Generation and Storage Asset Valuation, and Procurements
- Transmission Planning and Modeling
- Integrated Resource Planning
- Demand Response (DR) Resource Potential and Market Impact
- Gas-Electric Coordination
- RTO Participation and Configuration
- Energy Litigation
- Tariff and Rate Design
- Business Strategy

EXPERIENCE

Electricity Market Design and Analysis

- **Renewable Energy Tax Policy Impacts**. For a major developer or renewable energy, evaluated alternative proposals to extend/expand tax credits. Simulate investment, costs, prices and emissions nationally to 2050 using gridSIM, Brattle's next-generation capacity expansion model. Results informed client's policy position.
- **MISO Resource Adequacy Framework for a Transforming Fleet**. Currently advising MISO in its Resource Availability and Need initiative to reform its resource adequacy framework to address year-round shortage risks as the fleet transforms. Presenting to stakeholders on resource accreditation, determination of LSE

requirements, modifications to the Planning Reserve Auction, and interactions with outage scheduling and with energy and ancillary services markets.

- **Singapore Capacity Market Development**. For the Energy Market Authority (EMA) in Singapore, developing a complete forward capacity market design. Worked with EMA in collaboration with other government entities and stakeholders. Published high-level design documents and presented to stakeholders. Currently assisting with detailed design and implementation.
- **Clean Energy Transformation**. For NYISO, led a team to project how the fleet may evolve to meet the state's mandates for 70% renewable electricity by 2030 and 100% carbon-free electricity by 2040. Used GridSIM, an advanced capacity expansion model developed by Brattle, to model investment and operations subject to constraints on reliability and clean energy. Evaluated technology needs for meeting load during extended periods of low wind/solar. Study results are being used to inform forward-looking questions about market design and reliability.
- **Carbon Pricing to Harmonize NY's Wholesale Market and Environmental Goals.** Led a Brattle team to help NYISO: (1) develop and evaluate market design options, including mechanisms for charging emitters and allocating revenues to customers, border adjustments to prevent leakage, and interactions with other market design and policy elements; and (2) develop a model to evaluate how carbon pricing would affect market outcomes, emissions, system costs, and customer costs under a range of assumptions. Whitepaper initiated discussions with NY DPS and stakeholders. Supported NYISO in detailed market design and stakeholder engagement.
- **New York State Resource Adequacy Constructs**. For NYSERDA, evaluated the customer cost impacts of several alternative constructs that differ in whether FERC or the state sets the rules and how buyer-side mitigation is implemented.
- **IESO's Market Renewal Program / Energy Market Settlements**. For the Ontario Independent Electricity System Operator (IESO), helped develop settlement equations for the new day-ahead and real-time nodal market, including make-whole payments for natural gas-fired combined-cycle plants participating as "pseudo-units" and for cascading hydro systems.
- **PJM's Capacity Market Reviews and Parameters**. For PJM, conducted all four official reviews of its Reliability Pricing Model (2008, 2011, 2014, and 2018). Analyzed capacity auctions and interviewed stakeholders. Evaluated the demand curve shape, the Cost of New Entry (CONE) parameter, and the methodology for estimating net energy and ancillary services revenues. Recommended improvements to support participation and competition, to avoid excessive price volatility, and to safeguard future reliability performance. In 2020, provided Avoidable Cost Rates for existing resources and Net CONE for new energy efficiency resources, for use in the Minimum Offer Price Rule. Submitted testimonies before FERC.

- **Forward Energy and Ancillary Services (EA&S) Revenues in PJM**. For PJM, developed a method for using forward prices to estimate energy and ancillary services revenues for the purposes of determining capacity market parameters. Collaborated with Sargent & Lundy to establish resource characteristics, and with PJM staff to conduct hourly virtual dispatch. Filed successful testimony with FERC.
- **Seasonal Capacity in PJM.** On behalf of the Natural Resources Defense Council, analyzed the ability of PJM's capacity market to efficiently accommodate seasonal capacity resources and meet seasonal resource adequacy needs. Co-authored a whitepaper proposing a co-optimized two-season auction and estimating the efficiency benefits. Filed and presented report at FERC.
- **Energy Price Formation in PJM**. For NextEra Energy, analyzed PJM's integer relaxation proposal and evaluated implications for day-ahead and real-time market prices. Reviewed PJM's Fast-Start pricing proposal and authored report recommending improvements, which NextEra and other parties filed with FERC, and which FERC largely accepted and cited in its April 2019 Order.
- **Market Design for Energy Security in ISO-NE**. For NextEra Energy, evaluated and developed proposals for meeting winter energy security needs in New England when pipeline gas becomes scarce. Evaluated ISO-NE's proposed multi-day energy market with new day-ahead operating reserves. Developed competing proposal for new operating reserves in both day-ahead and real-time to incent preparedness for fuel shortages; also developed criteria and high-level approach for potentially incorporating energy security into the forward capacity market. Presented evaluations and proposals to the NEPOOL Markets Committee.
- **ERCOT's Proposed Future Ancillary Services Design**. For the Electric Reliability Council of Texas (ERCOT), evaluated the benefits of its proposal to unbundle ancillary services, enable broader participation by load resources and new technologies, and tune its procurement amounts to system conditions. Worked with ERCOT staff to assess each ancillary service and how generation, load resources, and new technologies could participate. Directed their simulation of the market using PLEXOS, and evaluated other benefits outside of the model.
- **Investment Incentives and Resource Adequacy in ERCOT**. For ERCOT, led a Brattle team to: (1) interview stakeholders and characterize the factors influencing generation investment decisions; (2) analyze the energy market's ability to support investment and resource adequacy at the target level; and (3) evaluate options to enhance long-term resource adequacy while maintaining market efficiency. Worked with ERCOT staff to understand the relevant aspects of their operations and market data. Performed probabilistic simulation analyses of prices, investment costs, and reliability. Conclusions informed a PUCT proceeding in which I filed comments and presented at several workshops.

- **Operating Reserve Demand Curve (ORDC) in ERCOT**. For ERCOT, evaluated several alternative ORDCs' effects on real-time price formation and investment incentives. Conducted backcast analyses using interval-level data provided by ERCOT and assuming generators rationally modify their commitment and dispatch in response to higher prices under the ORDC. Analysis was used by ERCOT and the PUCT to inform selection of final ORDC parameters.
- **Economically Optimal Reserve Margins in ERCOT**. For ERCOT, co-led studies (2014 and 2018) estimating the economically-optimal reserve margin, and the market equilibrium reserve margins in its energy-only market. Collaborated with ERCOT staff and Astrape Consulting to construct Monte Carlo economic and reliability simulations. Accounted for uncertainty and correlations in weather-driven load, renewable energy production, generator outages, and load forecasting errors. Incorporated intermittent wind and solar generation profiles, fossil generators' variable costs, operating reserve requirements, various types of demand response, emergency procedures, administrative shortage pricing under ERCOT's ORDC, and criteria for load-shedding. Reported economic and reliability metrics across a range of renewable penetration and other scenarios. Results informed the PUCT's adjustments to the ORDC to support desired reliability outcomes.
- **Australian Electricity Market Operator (AEMO) Redesign**. Advised AEMO on market design reforms for the National Electricity Market (NEM) to address concerns about operational reliability and resource adequacy as renewable generation displaces traditional resources. Also provided a report on potential auctions to ensure sufficient capabilities in the near-term.
- **Response to DOE's "Grid Reliability and Resiliency Pricing" Proposal**. For a broad group of stakeholders opposing the rule in a filing before FERC, evaluated DOE's proposed rule: the need (or lack thereof) for bolstering reliability and resilience by supporting resources with a 90-day fuel supply; the likely cost of the rule; and the incompatibility of DOE's proposed solution with the principles and function of competitive wholesale electricity markets.
- **Energy Market Power Mitigation in Western Australia**. Led a Brattle team to help Western Australia's Public Utilities Office design market power mitigation measures for its newly reformed energy market. Established objectives; interviewed stakeholders; assessed local market characteristics affecting the design; synthesized lessons learned from the existing energy market and from several international markets. Recommended criteria, screens, and mitigation measures for day-ahead and real-time energy and ancillary services markets. The Public Utilities Office posted our whitepaper in support of its conclusions.
- **MISO Competitive Retail Choice Solution.** For MISO, evaluated design alternatives for accommodating the differing needs of states relying on competitive retail choice and integrated resource planning. Conducted probabilistic simulations of likely

market results under alternative market designs and demand curves. Provided expert support in stakeholder forums and submitted expert testimony before FERC.

- **Buyer Market Power Mitigation**. On Behalf of the "Competitive Markets Coalition" group of generating companies, helped develop and evaluate proposals for improving PJM's Minimum Offer Price Rule so that it more effectively protects the capacity market from manipulation by buyers while reducing interference with non-manipulative activity. Participated in discussions with other stakeholders. Submitted testimony to FERC supporting tariff revisions that PJM filed.

- **Market Development Vision for MISO**. For the Midcontinent Independent System Operator (MISO), worked with MISO staff and stakeholders to codify a Market Vision as the basis for motivating and prioritizing market development initiatives over the next 2–5 years. Authored a foundational report for that Vision, including: describing the core services MISO must continue to provide to support a well-functioning market; establishing a set of principles for enhancing those services; identifying seven Focus Areas offering the greatest opportunities; and proposing criteria for prioritizing initiatives within and across Focus Areas.

- **ISO-NE Capacity Demand Curve Design.** For ISO New England (ISO-NE), developed a demand curve for its Forward Capacity Market. Solicited staff and stakeholder input, then established market design objectives. Provided a range of candidate curves and evaluated them against objectives, showing tradeoffs between reliability uncertainty and price volatility (using a probabilistic locational capacity market simulation model we developed). Worked with Sargent & Lundy to estimate the Net Cost of New Entry to which the demand curve prices are indexed. Submitted testimonies before FERC, which accepted the proposed curve.

- **Offer Review Trigger Prices in ISO-NE**. For the Internal Market Monitor in ISO-NE, developed benchmark prices for screening for uncompetitively low offers in the Forward Capacity Market. Worked with Sargent & Lundy to conduct bottom-up analyses of the costs of constructing and operating gas-fired generation technologies and onshore wind; also estimated the costs of energy efficiency and demand response. For each technology, estimated capacity payments needed to make the resource economically viable, given their costs and expected non-capacity revenues. Recommendations were filed with and accepted by the FERC.

- **Western Australia Capacity Market Design**. For the Public Utilities Office (PUO) of Western Australia, led a Brattle team to advise on the design and implementation of a new forward capacity market. Reviewed the high-level forward capacity market design proposed by the PUO; evaluated options for auction parameters such as the demand curve; recommended supplier-side and buyer-side market power mitigation measures; helped define administrative processes needed to conduct the auction and the governance of such processes.

- **Western Australia Reserve Capacity Mechanism**. For EnerNOC, evaluated Western Australia's administrative Reserve Capacity Mechanism in comparison with international capacity markets, and made recommendations for improvements to meet reliability objectives more cost effectively. Evaluated whether to develop an auction-based capacity market compared or an energy-only market design. Submitted report and presented recommendations to the Electricity Market Review Steering Committee and other senior government officials.
- **Evaluation of Moving to a Forward Capacity Market in NYISO.** For NYISO, conducted a benefit-cost analysis of replacing its prompt capacity market with a 4-year forward capacity market. Evaluated options based on stakeholder interviews and the experience of PJM and ISO-NE. Addressed risks to buyers and suppliers, market power mitigation, implementation costs, and long-run costs. Recommendations were used by NYISO and stakeholders to help decide whether to pursue a forward capacity market.
- **MISO's Resource Adequacy Construct and Market Design Elements.** For MISO, conducted the first major assessment of its resource adequacy construct. Identified several successes and recommended improvements in load forecasting, locational resource adequacy, and the determination of reliability targets. Incorporated extensive stakeholder input and review. Continued to consult with MISO in its work with the Supply Adequacy Working Group on design improvements, including market design elements for its annual locational capacity auctions.
- **Demand Response (DR) Integration in MISO**. Through a series of assignments, helped MISO incorporate DR into its energy market and resource adequacy construct, including: (1) conducted an independent assessment of MISO's progress in integrating DR into its resource adequacy, energy, and ancillary services markets. Analyzed market participation barriers; (2) wrote a whitepaper evaluating various approaches to incorporating economic DR in energy markets. Identified implementation barriers and recommended improvements to efficiently accommodate curtailment service providers; (3) helped modify MISO's tariff and business practices to accommodate DR in its resource adequacy construct by defining appropriate participation rules. Informed design by surveying the practices of other RTOs and by characterizing the DR resources within the MISO footprint.
- **Survey of Demand Response Provision of Energy, Ancillary Services, and Capacity.** For the Australian Energy Market Commission (AEMC), co-authored a report on market designs and participation patterns in several international markets. AEMC used the findings to inform its integration of DR into its National Energy Market.
- **Integration of DR into ISO-NE's Energy Markets.** For ISO-NE, provided analysis and assisted with a stakeholder process to develop economic DR programs to replace the ISO's initial economic DR programs when they expired.

- **Compensation Options for DR in ISO-NE's Energy Market**. For ISO-NE, analyzed the implications of various DR compensation options on consumption patterns, LMPs, capacity prices, consumer surplus, producer surplus, and economic efficiency. Presented findings in a whitepaper that ISO-NE submitted to FERC.
- **ISO-NE Forward Capacity Market (FCM) Performance.** With ISO-NE's internal market monitor, reviewed the performance of the first two forward auctions. Evaluated key design elements regarding demand response participation, capacity zone definition and price formation, an alternative pricing rule for mitigating the effects of buyer market power, the use of the Cost of New Entry in auction parameters, and whether to have an auction price ceiling and floor.
- **Evaluation of Tie-Benefits**. For ISO-NE, analyzed the implications of different levels of tie-benefits (i.e., assistance from neighbors, reducing installed capacity requirements) for capacity costs and prices, emergency procurement costs, and energy prices. Whitepaper submitted by ISO-NE to the FERC.
- **Evaluation of Major Initiatives**. With ISO-NE and its stakeholders, developed criteria for identifying "major" market and planning initiatives that trigger the need for the ISO to provide qualitative and quantitative information to help stakeholders evaluate the initiative, as required in ISO-NE's tariff. Developed guidelines on the kinds of information ISO-NE should provide for major initiatives.
- **Energy Market Monitoring & Market Power Mitigation**. For PJM, co-authored a whitepaper, "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets."
- **Vertical Market Power**. Before the NYPSC, examined whether the merger between National Grid and KeySpan could create incentives to exercise vertical market power. Employed a simulation-based approach using the DAYZER model of the NYISO wholesale power market and examined whether outages of National Grid's transmission assets significantly affected KeySpan's generation profits.
- **LMP Impacts on Contracts**. For a West Coast client, reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) in 2007 and analyzed implications for "seller's choice" supply contracts. Estimated congestion costs ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated incremental contract costs using a third party's GE-MAPS market simulations (and helped to improve their model inputs to more accurately reflect the transmission system in California). Applied findings to support the ISO in design modifications of the California market under LMP.
- **RTO Accommodation of Retail Access**. For MISO, identified business practice improvements to facilitate retail access. Analyzed retail access programs in IL, MI, and OH. Studied retail accommodation practices in other RTOs, focusing on how they modified their procedures surrounding transmission access, qualification of capacity resources, capacity markets, FTR allocations, and settlement.

Generation and Storage Asset Valuation, and Procurements

- **Value of Flexibility in ERCOT**. For a large company evaluating a range of investment strategies, assessed the value of flexibility in ERCOT today and in the future as wind and solar penetration increases. Used Brattle's GridSIM model to project investments and retirements over the next 10 years. Analyzed the likely increase in demand for ancillary services. Simulated system operations accounting for short-term uncertainty in net load forecasts, using ENELYTIX PSO to model day-ahead and real-time operations.
- **Storage Development Company Due Diligence**. For an international investor consider an equity investment in a storage development company in ERCOT, reviewed the developer's business model, interviewed the developer, and compared their revenue projections to our own.
- **Storage Asset Development in New York**. For a renewable generation company considering developing large new storage assets in New York City and Long Island, provided a market analysis, including a 20-year estimate of net revenues. Used Brattle's GridSIM model to simulate investment, operations, prices, and revenues over that timeframe, after calibrating the model to current actual prices.
- **Valuation of a Gas-Fired Combined-Cycle Plant in ERCOT**. For a generation company, estimated net revenues for an existing plant, using Brattle's GridSIM model to project investment/retirement, operations, prices, and revenues over that timeperiod, after calibrating the model to recent prices. Assessed market risks.
- **Evaluation of Hydropower Procurement Options**. For a potential buyer of new transmission and hydropower from Quebec, evaluated the costs and emissions benefits under a range of contracting approaches. Accounted for the possibility of resource shuffling and backfill of emissions. Considered the value of storage services.
- **Valuation of a Gas-Fired Combined-Cycle Plant in New England**. For a party to litigation, submitted testimony on the fair market value of the plant. Simulated energy and capacity markets to forecast net revenues, and estimated exposure to capacity performance penalties. Compared the valuation to the transaction prices of similar plants and analyzed the differences. Collaborated with a co-testifying export on project finance to assess whether the estimated value would suffice to cover the plant's debt and certain other obligations.
- **Valuation of a Portfolio of Combined-Cycle Plants across the U.S.** For a debt holder in a portfolio of plants, estimated the fair market value of each plant in 2018 and the plausible range of values five years hence. Reviewed comparables. Analyzed electricity markets in New England, New York, Texas, Arizona, and California using our own models and reference points from futures markets and publicly

available studies. Performed probability-weighted discounted cash flow valuation analyses across a range of scenarios. Provided insights into market and regulatory drivers and how they may evolve.

- **Wholesale Market Value of Storage in PJM**. For a potential investor in battery storage, estimated the energy, ancillary services, and capacity market revenues their technology could earn in PJM. Reviewed PJM's market participation rules for storage. Forecast capacity market revenues and the risk of performance penalties. Developed a real-time energy and ancillary service bidding algorithm that the asset owner could employ to nearly optimize its operations, given expected prices and operating constraints. Identified changes in real-time bid/offer rules that PJM could implement to improve the efficiency of market participation by storage resources.
- **Valuation of a Generation Portfolio in ERCOT**. For the owners of a portfolios of gas-fired assets (including a cogen plant), estimated the market value of their assets by modeling future cash flows from energy and ancillary services markets over a range of plausible scenarios. Analyzed the effects load growth, entry, retirements, environmental regulations, and gas prices could have on energy prices, including scarcity prices under ERCOT's Operating Reserve Demand Curve. Evaluated how future changes in these drivers could cause the value to shift over time.
- **Valuation Methodology for a Coal Plant Transaction in PJM**. For a part owner of a very large coal plant being transferred at an assessed value that was yet to be determined by a third party, wrote a manual describing how to conduct a market valuation of the plant. Addressed drivers of energy and capacity value; worked with an engineering subcontractor to describe how to determine the remaining life of the plant and CapEx needs going forward. Our manual was used to inform their pre-assessment negotiation strategy.
- **Valuation of a Coal Plant in PJM**. For the lender to a bidder on a coal plant being auctioned, estimated the market value of the plant. Valuation analysis focused especially on the effects of coal and gas prices on cash flows, and the ongoing fixed O&M costs and CapEx needs of the plant.
- **Valuation of a Coal Plant in New England**. For a utility, evaluated a coal plant's economic viability and market value. Projected market revenues, operating costs, and capital investments needed to comply with future environmental mandates.
- **Valuation of Generation Assets in New England**. To inform several potential buyers' valuations of various assets being sold in ISO-NE, provided energy and capacity price forecasts and cash flows under multiple scenarios. Explained the market rules and fundamentals to assess key risks to cash flows.
- **Valuation of Generation Asset Bundle in New England**. For the lender to the potential buyer of generation assets, provided long-term energy and capacity price forecasts, with multiple scenarios to test whether the plant could be worth less than

the debt. Reviewed a broad scope of documents available in the "data room" to identify market, operational, and fuel supply risks.

- **Valuation of Generation Asset Bundle in PJM**. For a potential buyer, provided energy and capacity price forecasts and reviewed their valuation analysis. Analyzed supply and demand fundamentals of the PJM capacity market. Performed locational market simulations using the DAYZER model to project nodal prices as market fundamentals evolve. Reviewed the client's spark spread options model.
- **Wind Power Development**. For a developer proposing to build a several hundred megawatt wind farm in Michigan, provided a revenue forecast for energy and capacity. Evaluated the implications of several scenarios around key uncertainties.
- **Wind Power Financial Modeling**. For an offshore wind developer proposing to build a 350 MW project in PJM off the coast of New Jersey, analyzed market prices for energy, renewable energy certificates, and capacity. Provided a detailed financial model of project funding and cash distributions to various types of investors (including production tax credit). Resulting financial statements were used in an application to the state of New Jersey for project grants.
- **Contract Review for Cogeneration Plant**. For the owner of a large cogen plant in PJM, analyzed revenues under the terms of a long-term PPA (in renegotiation) vs. potential merchant revenues. Accounted for multiple operating modes of the plant and its sales of energy, capacity, ancillary services, and steam over time.
- **Generation Strategy/Valuation**. For an independent power producer, acted for over two years as a key advisor on the implementation of the client's growth strategy. Led a large analytical team to assess the profitability of proposed new power plants and acquisitions of portfolios of plants throughout the U.S. Used the GE-MAPS market simulation model to forecast power prices, transmission congestion, generator dispatch, emissions costs, energy margins for candidate plants; used an ancillary model to forecast capacity value.
- **Generation Asset Valuation**. For multiple banks and energy companies, provided valuations of financially distressed generating assets. Used GE-MAPS to simulate net energy revenues; a capacity model to estimate capacity revenues; and a financial valuation model to value several natural gas, coal, and nuclear power plants across a range of scenarios. Identified key uncertainties and risks.

Transmission Planning and Modeling

- **Initial Report on the New York Power Grid Study**. With NYSERDA, NYDPS, and Pterra, submitted a report to the NYPSC projecting New York's transmission needs to support its long-term clean energy goals under the Climate Leadership and Community Protection Act. Our work synthesized findings from three sub-reports addressing local T&D needs, offshore wind, and overall bulk system needs.

- **Economic and Environmental Evaluation of New Transmission to Quebec**. For the New Hampshire Attorney General's Office in a proceeding before the state Site Evaluation Committee, co-sponsored testimony on the benefits of the proposed Northern Pass Transmission line. Responded to the applicant's analysis and developed our own, focusing on wholesale market participation, price impacts, and net emissions savings.
- **Benefit-Cost Analysis of New York AC Transmission Upgrades**. For the New York Department of Public Service (DPS) and NYISO, led a team to evaluate 21 alternative projects to increase transfer capability between Upstate and Southeast NY. Quantified a broad scope of benefits: traditional production cost savings from reduced congestion, using GE-MAPS; additional production cost savings considering non-normal conditions; resource cost savings from being able to retire Downstate capacity, delay new entry, and shift the location of future entry Upstate; avoided costs from replacing aging transmission that would have to be refurbished soon; reduced costs of integrating renewable resources Upstate; and tax receipts. Identified projects with greatest and most robust net value. DPS used our analysis to inform its recommendation to the NY Public Service Commission to declare a "Public Policy Need" to build a project such as the best ones identified.
- **Evaluation of New York Transmission Projects**. For the New York Department of Public Service (DPS), provided a cost-benefit analysis for the "TOTS" transmission projects. Showed net production cost and capacity resource cost savings exceeding the project costs, and the lines were approved. The work involved running GE-MAPS and a capacity market model, and providing insights to DPS staff.
- **Benefits of New 765kV Transmission Line**. For a utility joint venture between AEP and ComEd, analyzed renewable integration and congestion relief benefits of their proposed $1.2 billion RITELine project in western PJM. Guided client staff to conduct simulations using PROMOD. Submitted testimony to FERC.
- **Benefit-Cost Analysis of a Transmission Project for Offshore Wind**. Submitted testimony on the economic benefits of the Atlantic Wind Connection Project, a proposed 2,000 MW DC offshore backbone from New Jersey to Virginia with 7 onshore landing points. Described and quantified the effects on congestion, capacity markets, CO_2 emissions, system reliability and operations, jobs and economic stimulus, and the installed cost of offshore wind generation. Directed Ventyx staff to simulate the energy market impacts using the PROMOD model.
- **Analysis of Transmission Congestion and Benefits**. Analyzed the impacts on transmission congestion, and customer benefits in California and Arizona of a proposed inter-state transmission line. Used the DAYZER model to simulate congestion and power market conditions in the Western Electricity Coordination Council region in 2013 and 2020 considering increased renewable generation requirements and likely changes to market fundamentals.

- **Benefit-Cost Analysis of New Transmission**. For a transmission developer's application before the California Public Utility Commission (CPUC) to build a new 500 kV line, analyzed the benefits to ratepayers. Analysis included benefits beyond those captured in a production cost model, including the benefits of integrating a pumped storage facility that would allow the system to accommodate a larger amount of intermittent renewable resources at a reduced cost.
- **Benefit-Cost Analysis of New Transmission in the Midwest**. For the American Transmission Company (ATC), supported Brattle witness evaluating the benefits of a proposed new 345 kV line (Paddock-Rockdale). Advised client on its use of PROMOD IV simulations to quantify energy benefits, and developed metrics to properly account for the effects of changes in congestion, losses, FTR revenues, and LMPs on customer costs. Developed and applied new methodologies for analyzing benefits not quantified in PROMOD IV, including competitiveness, long-run resource cost advantages, reliability, and emissions. Testimony was submitted to the Public Service Commission of Wisconsin, which approved the line.
- **Transmission Investments and Congestion**. Worked with executives and board of an independent transmission company to develop a metric indicating congestion-related benefits provided by its transmission investments and operations.
- **Analysis of Transmission Constraints and Solutions**. For a large, geographically diverse group of clients, performed an in-depth study identifying the major transmission bottlenecks in the Western and Eastern Interconnections, and evaluating potential solutions to the bottlenecks. Worked with transmission engineers from multiple organizations to refine the data in a load flow model and a security-constrained, unit commitment and dispatch model for each interconnection. Ran 12-year, LMP-based market simulations using GE-MAPS across multiple scenarios and quantified congestion costs on major constraints. Collaborated with engineers to design potential transmission (and generation) solutions. Evaluated the benefits and costs of candidate solutions and identified several highly economic major transmission projects.
- **Merchant Transmission Impacts**. For a merchant transmission company, used GE-MAPS to analyze the effects of the Cross Sound Cable on energy prices.
- **Security-Constrained Unit Commitment and Dispatch Model Calibration**. For a Midwestern utility, calibrated their PROMOD IV model, focusing on LMPs, unit commitment, flows, and transmission constraints. Helped client to understand their model's shortcomings and identify improvement opportunities. Also assisted with initial assessments of FTRs in preparation for its submission of nominations in MISO's first allocation of FTRs.
- **Model Evaluation**. Led an internal Brattle evaluation of commercially available transmission and market simulation models. Interviewed vendors and users of PROMOD IV, Gridview, DAYZER, and other models. Intensively tested each

model. Evaluated accuracy of model algorithms (e.g., LMP, losses, unit commitment) and ability to calibrate models with backcasts using actual RTO data.

Integrated Resource Planning (IRP)

- **Resource Planning in Hawaii**. Assisted the Hawaiian Electric Companies in developing its Power Supply Improvement Plan, filed April 2016. Our work addressed how to maintain system security as renewable penetration increases toward 100% and displaces traditional synchronous generation. Solutions involved defining technology-neutral requirements that may be met by demand response, distributed resources, and new technologies as well as traditional resources.
- **IRP in Connecticut (for 2008, 2009, 2010, 2012, and 2014 Plans)**. For two major utilities and the state Dept. of Energy and Environmental Protection (DEEP), led the analysis for five successive IRPs. Plans involved projecting 10-year Base Case outlooks for resource adequacy, customer costs, emissions, and RPS compliance; developing alternative market scenarios; and evaluating resource procurement strategies focused on energy efficiency, renewables, and traditional sources. Used an integrated modeling system that simulated the New England locational energy market (with the DAYZER model), the Forward Capacity Market, REC markets, and suppliers' likely investment/retirement decisions. Addressed electricity supply risks, natural gas supply into New England, RPS standards, environmental regulations, transmission planning, emerging technologies, and energy security. Solicited input from stakeholders. Provided oral testimony before the DEEP.
- **Contingency Plan for Indian Point Nuclear Retirement**. For the New York Department of Public Service (DPS), assisted in developing contingency plans for maintaining reliability if the Indian Point nuclear plant were to retire. Evaluated generation and transmission proposals along three dimensions: their reliability contribution, viability for completion by 2016, and the net present value of costs. The work involved partnering with engineering sub-contractors, running GE-MAPS and a capacity market model, and providing insights to DPS staff.
- **Analysis of Potential Retirements to Inform Transmission Planning**. For a large utility in Eastern PJM, analyzed the potential economic retirement of each coal unit in PJM under a range of scenarios regarding climate legislation, legislation requiring mercury controls, and various capacity price trajectories.
- **Resource Planning in Wisconsin**. For a utility considering constructing new capacity, demonstrated the need to consider locational marginal pricing, gas price uncertainty, and potential CO_2 liabilities. Guided client to look beyond building a large coal plant. Led them to mitigate exposures, preserve options, and achieve nearly the lowest expected cost by pursuing a series of smaller projects, including a promising cogeneration application at a location with persistently high LMPs.

Conducted interviews and facilitated discussions with senior executives to help the client gain support internally and begin to prepare for regulatory communications.

Demand Response (DR) Resource Potential and Market Impact

- **ERCOT DR Potential Study**. For ERCOT, estimated the market size for DR by end-user segment based on interviews with curtailment service providers and utilities and informed by penetration levels achieved in other regions. Presented findings to the Public Utility Commission of Texas at a workshop on resource adequacy.
- **DR Potential Study**. For an Eastern ISO, analyzed the potential for DR and price responsive demand in the footprint, and what the ISO could do to facilitate them. For each segment of the market, identified the ISO and/or state and utility initiatives that would be needed to develop various levels of capacity and energy market response. Also estimated the potential and cost characteristics for each segment. Interviewed numerous curtailment service providers and ISO personnel.
- **Wholesale Market Impacts of Price-Responsive Demand (PRD)**. For NYISO, evaluated the potential effects of widespread implementation of dynamic retail rates. Utilized the PRISM model to estimate effects on consumption by customer class, applied empirically-based elasticities to hourly differences between flat retail rates and projected dynamic retail rates. Utilized the DAYZER model to estimate the effects of load changes on energy costs and prices.
- **Energy Market Impacts of DR**. For PJM and the Mid-Atlantic Distributed Resources Initiative (sponsored by five state commissions), quantified the market impacts and customer benefits of DR programs. Used a simulation-based approach to quantify the impact that a three percent reduction of peak loads during the top 20 five-hour blocks would have had in 2005 and under a variety of alternative market conditions. Utilized the DAYZER market simulation model, which we calibrated to represent the PJM market using data provided by PJM and public sources. Results were presented in multiple forums and cited widely, including by several utilities in their filings with state commissions regarding investment in advanced metering infrastructure and implementation of DR programs.
- **Value of DR Investments**. For Pepco Holdings, Inc., evaluated its proposed DR-enabling investments in advanced metering infrastructure and its efficiency programs. Estimated reductions in peak load that would be realized from dynamic pricing, direct load control, and efficiency. Built on the Brattle-PJM-MADRI study to estimate short-term energy market price impacts and addressed long-run equilibrium offsetting effects through supplier response scenarios. Estimated capacity price impacts and resource cost savings over time. Submitted a whitepaper to DE, NJ, MD, and DC commissions. Presented findings to DE Commission.

Gas-Electric Coordination

- **Gas Pipeline Investment for Electricity.** For the Maine Office of Public Advocate, co-sponsored testimony regarding the reliability and economic impacts if the Maine PUC signed long-term contracts for electricity customers to pay for new gas pipeline capacity into New England. Analyzed other experts' reports and provided a framework for evaluating whether such procurements would be in the public interest, considering their costs and benefits vs. alternatives.
- **Gas Pipeline Investment for Electricity.** For the Massachusetts Attorney General's office, provided input for their comments in the Massachusetts Department of Public Utilities' docket investigating whether and how new natural gas delivery capacity should be added to the New England market.
- **Fuel Adequacy and Other Winter Reliability Challenges**. For an ISO, co-authored a report assessing the risks of winter reliability events due to inadequate fuel, inadequate weatherization, and other factors affecting resource availability in the winter. Evaluated solutions being pursued by other ISOs. Proposed changes to resource adequacy requirements and energy market design to mitigate the risks.
- **Gas-Electric Reliability Challenges in the Midcontinent**. For MISO, provided a PowerPoint report assessing future gas-electric challenges as gas reliance increases. Characterized solutions from other ISOs. Provided inputs on the cost of firm pipeline gas vs. the cost and operational characteristics of dual-fuel capability.

RTO Participation and Configuration

- **Market Impacts of RTO Seams**. For a consortium of utilities, submitted written testimony to the FERC analyzing the financial and operational impact of the MISO-PJM seam on Michigan and Wisconsin. Evaluated economic hurdles across RTO seams and assessed the effectiveness of inter-RTO coordination efforts underway. Collaborated with MISO staff to leverage their PROMOD IV model to simulate electricity markets under alternative RTO configurations.
- **Analysis of RTO Seams**. For a Wisconsin utility in a proceeding before the FERC, assisted expert witness on (1) MISO and PJM's real-time inter-RTO coordination process, and (2) the economic benefit of implementing a full joint-and-common market. Analyzed lack of convergence between MISO's and PJM's energy prices and shadow prices on reciprocal coordinated flow gates.
- **RTO Participation**. For an integrated Midwest utility, advised client on alternative RTO choices. Used GE-MAPS to model the transmission system and wholesale markets under various scenarios. Presented findings to senior management. Subsequently, in support of testimonies submitted to two state commissions, quantified the benefits and costs of RTO membership on customers, considering energy costs, FTR revenues, and wheeling revenues.

Energy Litigation

- **Enforcement Matter in ISO-NE's Day-Ahead Load Response Program**. Provided expert testimony on behalf of the FERC Office of Enforcement in "Fed. Energy Regulatory Comm'n v. Silkman" in the U.S. District Court of Maine regarding allegations that defendant "engag[ed] in a fraudulent scheme to manipulate the ISO New England, Inc. (ISO-NE) Day-Ahead Load Response Program" by gaming the baseline and claiming false reductions in load. Submitted initial and rebuttal reports analyzing whether defendant's conduct was consistent with industry practice and the purpose of demand response. Matter settled.
- **Valuation of Alleged Misrepresentations of Demand Response Company.** Provided expert testimony on behalf of a client that had acquired a demand response company and alleged that the company had overstated its demand response capacity and technical capabilities. Analyzed discovery materials including detailed demand response data to assess the magnitude of alleged overstatements. Calculated damages primarily based on a fair market valuation of the company with and without alleged overstatements. Provided deposition, expert report, and oral testimony before the American Arbitration Association (non-public).
- **Contract Damages.** For the California Department of Water Resources and the California Attorney General's office, supported expert providing testimony on damages resulting from an electricity supplier's alleged breaches of a power purchase agreement. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration. Resulted in successful award for client.
- **Contract Damages**. For the same client described above, supported expert providing testimony in arbitration regarding the supplier's alleged breaches in which its scheduled deliveries were not deliverable due to transmission congestion. Quantified damages and demonstrated the predictability of congestion, which the supplier was allegedly supposed to avoid in its choice of delivery points.
- **Contract Termination Payment**. For an independent power producer, supported expert testimony on damages from the termination of a long-term tolling contract for a gas-fired power plant in PJM, involving power market forecasting, financial valuation techniques, and a detailed assessment of the plant's costs and operating characteristics. Prepared witness for arbitration and assisted counsel in deposing and cross-examining opposing experts. Resulted in resounding victory for client.

Tariff and Rate Design

- **Wholesale Rates.** On behalf of a G&T co-op in the Western U.S., provided testimony regarding its wholesale rates, which are contested by member co-ops. Analyzed the G&T co-op's cost of service and its marginal cost of meeting customers' energy and peak demand requirements.
- **Transmission Tariffs**. For a merchant generating company participating in FERC hearings on developing a Long Term Transmission Pricing Structure, helped lead a coalition of stakeholders to develop a position on how to eliminate pancaked transmission rates while allowing transmission owners to continue to earn their allowed rate of return. Analyzed and presented the implications of various transmission pricing proposals on system efficiency, incentives for new investment, and customer rates throughout the MISO-PJM footprint.
- **Retail Rate Riders**. For a traditionally regulated Midwest utility, helped general counsel to evaluate and support legislation, and propose commission rules addressing rate riders for fuel and purchased power and the costs of complying with environmental regulations. Performed research on rate riders in other states; drafted proposed rules and tariff riders for client.
- **Rate Filings**. For a traditionally regulated Midwest utility, assisted counsel in preparing for a rate case. Helped draft testimonies regarding off-system sales margins and the cost of fuel.

Business Strategy

- **Preparing a Gentailer for a Transformed Wholesale Market Design.** Supported a gentailer in Alberta to prepare its generation and retail businesses for the implementation of a capacity market.
- **Evaluation of Cogeneration Venture**. For an unregulated division of a utility, evaluated a venture to build and operate cogeneration facilities. Estimated the market size and potential pricing, and assessed the client's capabilities for delivering such services. Analyzed the target customer base in detail; performed technical cost analysis for building and operating cogeneration plants; analyzed retail/default rate structures against which new cogeneration would have to compete. Senior management followed our recommendations to shut down the venture.
- **Strategic Sourcing**. For a large, diversified manufacturer, coordinated a cross-business unit client team to reengineer processes for procuring electricity, natural gas, and demand-side management services. Worked with executives to establish goals. Gathered data on energy usage patterns, costs, and contracts across hundreds of facilities. Interviewed energy managers, plant managers, and executives. Analyzed potential suppliers. Helped draft RFPs and develop negotiating strategy.

Designed internal organizational structure (incorporating outsourced service providers) for managing energy procurement on an ongoing basis.

- **M&A Advisory**. For a European utility aiming to enter the U.S. markets and enhance its trading capability, evaluated acquisition targets. Assessed potential targets' capabilities and their value versus stock price. Reviewed experiences of acquirers in other M&A transactions. Advised client against an acquisition, just when the market was peaking (just prior to collapse).
- **Marketing Strategy**. For a power equipment manufacturer, identified the most attractive target customers and joint-venture candidates for plant maintenance services. Evaluated the cost structure and equipment mix of candidates using FERC data and proprietary data. Estimated the value client could bring to each customer. Worked with company president to translate findings into a marketing strategy.
- **Distributed Generation (DG) Market Assessment**. For the unregulated division of a major utility, performed a market assessment of DG technologies. Projected future market sizes by market segments in the U.S.
- **Fuel Cells**. For a European fuel cell manufacturer, served as a technology and electricity market advisor for a larger consulting team developing a market entry strategy in the U.S.

TESTIMONY and REGULATORY FILINGS

Before the FERC, Docket No. EL21-7-000, "Written Testimony of Dr. Kathleen Spees and Dr. Samuel A. Newell" on behalf of the Natural Resource Defense Council, the Sustainable FERC Project, Earthjustice, Sierra Club, American Wind Energy Association, Alliance for Clean Energy New York, and Advanced Energy Economy, regarding the economic impacts of buyer-side mitigation in the NYISO capacity market, November 18, 2020.

Before the NY Public Service Commission, Case 19-T-0684, "Rebuttal Testimony of Samuel A. Newell on Behalf of New York Transco LLC," in response to the direct testimony of Cricket Valley Energy Center, LLC and Guidehouse Inc. regarding the economic benefits of Transco's proposed "Segment B" transmission project, September 30, 2020.

Before the FERC, Docket Nos. EL19-58 and ER19-1486, "Supplemental Affidavit of Samuel A. Newell and James A. Read Jr. on Behalf of PJM Interconnection, L.L.C.," regarding the use of forward-looking data to estimate energy and ancillary services revenues for the purposes of determining capacity market parameters, September 17, 2020.

Before the FERC, Docket Nos. EL19-58 and ER19-1486, "Affidavit of Samuel A. Newell, James A. Read Jr., and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the use of forward-looking data to estimate energy and ancillary services revenues for the purposes of determining capacity market parameters, August 5, 2020.

Before the FERC, Docket Nos. EL16-49, ER18-1314-000, ER18-1314-001, EL18-178-000 (Consolidated), "Supplemental Affidavit of Samuel A. Newell, John M. Hagerty and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the expansion of the Minimum Offer Price Rule in its forward capacity market, March 23, 2020.

Before the FERC, Docket Nos. EL16-49, ER18-1314-000, ER18-1314-001, EL18-178-000 (Consolidated), "Affidavit of Samuel A. Newell, John M. Hagerty and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the expansion of the Minimum Offer Price Rule in its forward capacity market, March 17, 2020.

Before the Indiana General Assembly 21st Century Energy Policy Development Task Force, "Electricity Transmission Basics," on behalf of the Indiana Energy Association, October 17, 2019.

Before the FERC, Docket No. ER19-105-000, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, "Affidavit of Samuel A. Newell, John M. Hagerty, and Sang H. Gang on Behalf of PJM Interconnection, L.L.C.," regarding the Cost of New Entry, accompanied by report, *PJM Cost of New Entry Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, October 12, 2018.

Before the FERC, Docket No. ER19-105-000, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, "Affidavit of Dr. Samuel A. Newell and David Luke Oates on behalf of PJM Interconnection, L.L.C," regarding the Variable Resource Requirement Curve Shape, accompanied by report, *Fourth Review of PJM's Variable Resource Requirement Curve*, October 12, 2018.

Before the FERC, Docket Nos. EL16-49-000, ER18-1314-000, ER18-1314-001, EL18-178-000 (Consolidated), Affidavit of Kathleen Spees and Samuel A. Newell Regarding the Need for a Self-Supply Exemption from Minimum Offer Price and Other Policy Supported Resource Rules on behalf of Dominion Energy Services, Inc. and Virginia Electric and Power Company, October 2, 2018.

Before the FERC, Docket Nos. EL17-32-000 and EL17-36-000, Prefiled Comments of Samuel A. Newell, Kathleen Spees, and Yingxia Yang on behalf on behalf of the Natural Resources Defense Council: "Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM," April 15, 2018; presented oral testimony on the Seasonality Panel at FERC's Seasonal Capacity Technical Conference on April 24, 2018.

Before the FERC, Docket No. EL18-34-000, Samuel A. Newell, Pablo A. Ruiz, and Rebecca C. Carroll, "Evaluation of PJM's Fast-Start Pricing Proposal," report prepared for NextEra Energy Resources and attached to *Reply Brief of Joint Commenters*, March 14, 2018.

Before the U.S. District Court of Maine, in "Fed. Energy Regulatory Comm'n v. Silkman" (1:16-cv-00205-JAW), submitted "Expert Report of Samuel A. Newell" on behalf of the FERC Office of Enforcement, January 29, 2018, and "Rebuttal Report of Samuel A. Newell," March 15, 2018.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, oral testimony and cross examination on the electricity market impacts of the proposed Northern Pass Transmission Project, October 26-27, 2017.

Before the FERC, Docket No. AD17-11-000, Prefiled Comments of Samuel A. Newell re "Reconciling Wholesale Competitive Markets with State Polices," April 25, 2017; and oral testimony on Industry Expert Panel at the Technical Conference on May 2, 2017.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, Prefiled Supplemental Testimony of Samuel Newell and Jurgen Weiss on behalf of the New Hampshire Counsel for the Public, with attached report, "Electricity Market Impacts of the Proposed Northern Pass Transmission Project--Supplemental Report," April 17, 2017.

Before the FERC, Docket No. ER17-284-000, filed "Response of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," January 13, 2017.

Before the New Hampshire Site Evaluation Committee, Docket No. 2015-06, Prefiled Direct Testimony of Samuel Newell and Jurgen Weiss on behalf of the New Hampshire Counsel for the Public, with attached report, "Electricity Market Impacts of the Proposed Northern Pass Transmission Project," December 30, 2016.

Before the FERC, Docket No. ER17-284-000, filed "Testimony of Dr. Samuel A. Newell, Dr. Kathleen Spees, and Dr. David Luke Oates on behalf of Midcontinent Independent System Operator Regarding the Competitive Retail Solution," November 1, 2016.

"Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," Appendix 1 to Comparative Evaluation of Alternating Current Transmission Upgrade Alternatives, Trial Staff Final Report, *Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades*, New York State Department of Public Service, Matter No. 12-02457, Case No. 12-T-0502, September 22, 2015. Presented to NYISO and DPS Staff at the Technical Conference, Albany, NY, October 8, 2015.

Before the Maine Public Utilities Commission, Docket No. 2014-00071, filed "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on Behalf of the Maine Office of the Public Advocate, Comments on LEI's June 2015 Report and Recommendations for a Regional Analysis," November 18, 2015.

Before the FERC, Docket No. ER14-2940-000, filed "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC Regarding Variable Resource Requirement Curve," for use in PJM's capacity market, November 5, 2014.

Before the FERC, Docket No. ER15-68-000, filed "Affidavit of Dr. Samuel A. Newell on behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's Minimum Offer Price Rule, October 9, 2014.

Before the Texas House of Representatives Environmental Regulation Committee, Hearing on the Environmental Protection Agency's Newly Proposed Clean Power Plan and Potential Impact on Texas, invited by Committee Chair to present, "EPA's Clean Power Plan: Basics of the Rule, and Implications for Texas," Austin, TX, September 29, 2014.

Before the FERC, Docket No. ER14-2940-000, filed "Affidavit of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's capacity market, September 25, 2014.

Before the FERC, Docket No. ER14-2940-000, filed "Affidavit of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC Regarding Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters," September 25, 2014.

Before the Public Utilities Commission of the State of Colorado, Proceeding No. 13F-0145E, "Answer Testimony and Exhibits of Samuel A. Newell on Behalf of Tri-State Generation and Transmission Association, Inc.," regarding an analysis of complaining parties' responses to Tri-State Generation and Transmission Association, Inc.'s Third Set of Data Requests, Interrogatory, September 10, 2014.

Before the Maine Public Utilities Commission, Docket No. 2014-00071, "Testimony of Dr. Samuel A. Newell and Matthew P. O'Loughlin on Behalf of the Maine Office of the Public Advocate, Analysis of the Maine Energy Cost Reduction Act in New England Gas and Electricity Markets," July 11, 2014.

Before the FERC, Docket No. ER14-1639-000, filed "Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees on behalf of ISO New England Inc. Regarding a Forward Capacity Market Demand Curve," April 1, 2014.

Before the FERC, Docket No. ER14-1639-000, filed "Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry for The Forward Capacity Market Demand Curve," April 1, 2014.

Before the FERC, Docket No. ER14-616-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of ISO New England Inc.," and accompanying "2013 Offer Review Trigger Prices Study," regarding the Minimum Offer Price Rule new capacity resources in capacity auctions, December 13, 2013.

Before the American Arbitration Association, provided expert testimony (deposition, written report, and oral testimony at hearing) in a dispute involving the acquisition of a demand response company, July-November, 2013. (Non-public).

Before the Public Utility Commission of Texas, at a workshop on Project No. 40000, presented "Report On ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates Prepared By The Brattle Group," on behalf of The Electric Reliability Council of Texas (ERCOT), June 25, 2013. Subsequently filed additional comments, "Additional ORDC B+ Economic Equilibrium Planning Reserve Margin Estimates," July 29, 2013.

Before the FERC, Docket No. ER13-535-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of the 'Competitive Markets Coalition' Group Of Generating Companies," supporting PJM's proposed tariff revisions to change certain terms regarding the Minimum Offer Price Rule in the Reliability Pricing Model, December 28, 2012.

Before the FERC, Docket No. ER12-513-000, filed "Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC," in support of PJM's Settlement Agreement regarding the Cost of New Entry for use in PJM's capacity market, November 21, 2012.

Before the Texas House of Representatives State Affairs Committee, Hearing on the issue of resource adequacy in the Texas electricity market, presented "The Resource Adequacy Challenge in ERCOT," on behalf of The Electric Reliability Council of Texas, October 24, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "Resource Adequacy in ERCOT: 'Composite' Policy Options," and "Estimate of DR Potential in ERCOT" on behalf of The Electric Reliability Council of Texas (ERCOT), October 25, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "ERCOT Investment Incentives and Resource Adequacy," September 6, 2012.

Before The Public Utility Commission of Texas, at a workshop on Project No. 40480, presented "Summary of Brattle's Study on ERCOT Investment Incentives and Resource Adequacy," July 27, 2012.

Before the FERC, Docket No. ER12-___-000, Affidavit of Dr. Samuel A. Newell on Behalf of SIG Energy, LLLP, March 29, 2012, Confidential Exhibit A in Complaint of Sig Energy, LLLP, SIG Energy, LLLP v. California Independent System Operator Corporation, Docket No. EL 12-___-000, filed April 4, 2012 (Public version, confidential information removed).

Before the FERC, Docket No. ER12-13-000, filed "Response of Dr. Samuel A. Newell and Dr. Kathleen Spees on Behalf of PJM Interconnection, LLC," regarding the Cost of New Entry for use in PJM's capacity market, January 13, 2012.

Before the FERC, Docket No. ER12-13-000, Affidavit of Dr. Samuel A. Newell on Behalf of PJM Interconnection, LLC, re: the Cost of New Entry Estimates for Delivery Year 2015/16 in PJM's Reliability Pricing Model, filed December 1, 2011.

Before the FERC, Docket Nos. ER11-4069 and ER11-4070, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of the RITELine Companies, re: the public policy, congestion relief, and economic benefits of the RITELine Transmission Project, filed July 18, 2011.

Before the FERC, Docket No. No. EL11-13-000, Direct testimony of Johannes Pfeifenberger and Samuel Newell on behalf of The AWC Companies re: the public policy, reliability, congestion relief, and economic benefits of the Atlantic Wind Connection Project, filed December 20, 2010.

"Economic Evaluation of Alternative Demand Response Compensation Options," whitepaper filed by ISO-NE in its comments on FERC's Supplemental Notice of Proposed Rulemaking in Docket No. RM10-17-000, October 13, 2010 (with K. Madjarov).

Before the FERC, Docket No. RM10-17-000, Filed Comments re: Supplemental Notice of Proposed Rulemaking and September 13, 2010 Technical Conference, October 5, 2010 (with K. Spees and P. Hanser).

Before the FERC, Docket No. RM10-17-000, Filed Comments re: Notice of Proposed Rulemaking regarding wholesale compensation of demand response, May 13, 2010 (with K. Spees and P. Hanser).

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2010 "Integrated Resource Plan for Connecticut" (see below), June 2010.

2010 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 4, 2010. Presented to the Connecticut Energy Advisory Board January 8, 2010.

"Dynamic Pricing: Potential Wholesale Market Benefits in New York State," lead authors: Samuel Newell and Ahmad Faruqui at The Brattle Group, with contributors Michael Swider, Christopher Brown, Donna Pratt, Arvind Jaggi and Randy Bowers at the New York Independent System Operator, submitted as "Supplemental Comments of the NYISO Inc. on the Proposed Framework for the Benefit-Cost Analysis of Advanced Metering Infrastructure," in State of New York Public Service Commission Case 09-M-0074, December 17, 2009.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2009 "Integrated Resource Plan for Connecticut" (see below), June 30, 2009.

2009 "Integrated Resource Plan for Connecticut," report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board, January 1, 2009.

"Informational Filing of the Internal Market Monitoring Unit's Report Analyzing the Operations and Effectiveness of the Forward Capacity Market," prepared by Dave LaPlante and Hung-po Chao of ISO-NE with Sam Newell, Metin Celebi, and Attila Hajos of The Brattle Group, filed with FERC on June 5, 2009 under Docket No. ER09-1282-000.

Before the Connecticut Department of Public Utility Control, provided oral testimony to support the 2008 "Integrated Resource Plan for Connecticut" and "Supplemental Reports" (see below), September 22, 2008.

"Integrated Resource Plan for Connecticut," co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Energy Advisory Board; co-authored with M. Chupka, A. Faruqui, and D. Murphy, January 2, 2008. Supplemental Report co-submitted with The Connecticut Light & Power Company and The United Illuminating Company to the Connecticut Department of Utility Control; co-authored with M. Chupka, August 1, 2008.

"Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs," whitepaper by Samuel A. Newell and Ahmad Faruqui filed by Pepco Holdings, Inc. with the Public Utility Commissions of Delaware (Docket No. 07-28, 9/27/2007), Maryland (Case No. 9111, filed 12/21/07), New Jersey (BPU Docket No. EO07110881, filed 11/19/07), and Washington, DC (Formal Case No. 1056, filed 10/1/07). Presented orally to the Public Utility Commission of Delaware, September 5, 2007.

Before the Public Service Commission of Wisconsin, Docket 137-CE-149, "Planning Analysis of the Paddock-Rockdale Project," report by American Transmission Company re: transmission cost-benefit analysis, April 5, 2007 (with J.P. Pfeifenberger and others).

Prepared Supplemental Testimony on Behalf of the Michigan Utilities before the FERC, Docket No. ER04-718-000 et al., re: Financial Impact of ComEd's and AEP's RTO Choices, December 21, 2004 (with J. P. Pfeifenberger).

Prepared Direct and Answering Testimony on Behalf of the Michigan-Wisconsin Utilities before the FERC, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, September 15, 2004 (with J.P. Pfeifenberger).

Declaration on Behalf of the Michigan-Wisconsin Utilities before the FERC, Docket No. ER04-375-002 et al., re: Financial Impact of ComEd's and AEP's RTO Choices on Michigan and Wisconsin, August 13, 2004 (with J.P. Pfeifenberger).

PUBLICATIONS

Offshore Wind Transmission: An Analysis of Options for New York, report prepared for Anbaric, August 2020 (with J. Pfeifenberger, W. Graf, and K. Spokas).

Singapore Foreward Capacity Market—FCM Design Proposal (third Consultation Paper), prepared for the Singapore Energy Market Authority, May 2020 (with J. Chang and W. Graf). Followed draft proposals in first and second Consultation papers in May 2019 and Dec 2019.

Quantitative Analysis of Resource Adequacy Structures, report prepared for NYSERDA and NYSDPS, July 1, 2020 (with K. Spees, J. Imon Pedtke, and M. Tracy). Update to version from May 29, 2020.

New York's Evolution to a Zero Emission Power System: Modeling Operations and Investment Through 2040 Including Alternative Scenarios, report prepared for NYISO Stakeholders, June 22, 2020 (with R. Lueken, J. Weiss, S. Crocker Ross, and J. Moraski). Update to version from May 18, 2020.

Qualitative Analysis of Resource Adequacy Structures for New York, report prepared for NYSERDA and NYSDPS, May 19, 2020 (with K. Spees and J. Imon Pedtke).

Offshore Transmission in New England: The Benefits of a Better-Planned Grid, report prepared for Anbaric, May 2020 (with J. Pfeifenberger and W. Graf).

Implementing Recommended Improvements to Market Power Mitigation in the WEM, report prepared for Energy Policy WA in Western Australia, April 2020 (with T. Brown).

Gross Avoidable Cost Rates for Existing Generation and Net Cost of New Entry for New Energy Efficiency, report prepared for PJM, March 17, 2020 (with M. Hagerty, S. Sergici, E. Cohen, S. Gang, J. Wroble, and P. Daou).

"Forward Clean Energy Markets: A New Solution to State-RTO Conflicts," *Utility Dive*, January 27, 2020 (with K. Spees and J. Pfeifenberger.)

How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals: Through a Forward Market for Clean Energy Attributes: Expanded Report Including a Detailed Market Design Proposal, report prepared for NRG, September 2019 (with K. Spees, W. Graf, and E. Shorin).

International Review of Demand Response Mechanisms in Wholesale Markets, report for the Australian Energy Market Commission, June 2019 (with T. Brown, K. Spees, and C. Wang).

How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals: Through a Forward Market for Clean Energy Attributes, report prepared for NRG, April 2019 (with K. Spees, W. Graf, and E. Shorin).

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"Market-Based Approaches to Support States' Decarbonization Objectives," panelist at Independent Power Producers of New York (IPPNY) 2017 Spring Conference, Albany, NY, May 10, 2017.

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"PJM Capacity Auction Results and Market Fundamentals," presented to Bloomberg Analyst Briefing Webinar, September 18, 2015 (with J. Pfeifenberger and D.L. Oates).

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"Market Changes to Promote Fuel Adequacy—Capacity Market to Promote Fuel Adequacy," presented to INFOCAST- Northeast Energy Summit 2014 Panel Discussion, Boston, MA, September 17, 2014.

"EPA's Clean Power Plan: Basics and Implications of the Proposed CO_2 Emissions Standard on Existing Fossil Units under CAA Section 111(d)," presented to Goldman Sachs Power, Utilities, MLP and Pipeline Conference, New York, NY, August 12, 2014.

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"The State of Things: Resource Adequacy in ERCOT," presented to INFOCAST – ERCOT Market Summit 2014 Panel Discussion, Austin, TX, February 24-26, 2014.

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"Texas Resource Adequacy," presented to Power Across Texas, Austin, TX, September 21, 2012.

"Resource Adequacy and Demand Response in ERCOT," presented to the Center for the Commercialization of Electric Technologies (CCET) Summer Board Meeting, Austin, TX, August 8, 2012.

"Summary of Brattle's Study on 'ERCOT Investment Incentives and Resource Adequacy'," presented to the Texas Industrial Energy Consumers annual meeting, Austin, TX, July 18, 2012.

"Market-Based Approaches to Achieving Resource Adequacy," presentation to Energy Bar Association Northeast Chapter Annual Meeting, Philadelphia, PA, June 6, 2012.

"Fundamentals of Western Markets: Panel Discussion," WSPP's Joint EC/OC Meeting, La Costa Resort, Carlsbad, CA, February 26, 2012 (with J. Weiss).

"Integrated Resource Planning in Restructured States," presentation at EUCI conference on "Supply and Demand-Side Resource Planning in ISO/RTO Market Regimes," White Plains, NY, October 17, 2011.

"Demand Response Gets Market Prices: Now What?" NRRI teleseminar panelist, June 9, 2011.

Before the PJM Board of Directors and senior level representatives at PJM's General Session, panel member serving as an expert in demand response on behalf of Pepco Holdings, Inc., December 22, 2007.

"Resource Adequacy in New England: Interactions with RPS and RGGI," Energy in the Northeast Law Seminars International Conference, Boston, MA, October 18, 2007.

"Corporate Responsibility to Stakeholders and Criteria for Assessing Resource Options in Light of Environmental Concerns," Bonbright Electric & Natural Gas 2007 Conference, Atlanta, GA, October 3, 2007.

"Evaluating the Economic Benefits of Transmission Investments," EUCI's Cost-Effective Transmission Technology Conference, Nashville, TN, May 3, 2007 (with J. Pfeifenberger, presenter).

"Quantifying Demand Response Benefits in PJM," PowerPoint presentation to the Mid-Atlantic Distributed Resources Initiative (MADRI) Executive Committee on January 13, 2007, to the MADRI Working Group on February 6, 2007, as Webinar to the U.S. Demand Response Coordinating Council, and to the Pennsylvania Public Utility Commission staff April 27, 2007.

"Who Will Pay for Transmission," CERA Expert Interview, Cambridge, MA, January 15, 2004.

"Reliability Lessons from the Blackout; Transmission Needs in the Southwest," presented at the Transmission Management, Reliability, and Siting Workshop sponsored by Salt River Project and the University of Arizona, Phoenix, AZ, December 4, 2003.

"Application of the 'Beneficiary Pays' Concept," presented at the CERA Executive Retreat, Montreal, Canada, September 17, 2003.

<u>EXHIBIT C</u>

Testimony of Michael Goggin

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)** **)** **)**	**Docket No. ER22-1528**

AFFIDAVIT OF MICHAEL GOGGIN

I. INTRODUCTION AND QUALIFICATIONS

My name is Michael Goggin, and I am Vice President of Grid Strategies LLC.

I have been retained by RENEW Northeast, Natural Resources Defense Council, Sierra Club, Conservation Law Foundation, Acadia Center, the Environmental Defense Fund, Sustainable FERC Project, Massachusetts Climate Action Network, PowerOptions, E2 (Environmental Entrepreneurs), and American Clean Power Association (collectively "Clean Energy and Consumer Advocates") to submit this affidavit in support of the Clean Energy and Consumer Advocates' protest regarding the Independent System Operator, New England ("ISO-NE" or "ISO") Tariff filing made in Docket ER22-1528 on March 31, 2022.[1]

I have worked on wholesale power market design issues for approximately 15 years, including over 10 years at the American Wind Energy Association (now the American Clean Power Association) and the last 4 years at Grid Strategies. I have testified before FERC and in more than two dozen state utility regulatory commission proceedings. At Grid Strategies I advise private-sector, public-sector, and non-government organization clients on a range of economic issues related to electricity market design and performance, power generation economics, utility regulatory policy, and the economic impacts of state and federal environmental policies. In the

[1] Revisions to ISO New England Transmission, Markets and Services Tariff of Buyer-Side Market Power Review and Mitigation Reforms (Mar. 31, 2022), Accession No. 20220331-5296 ("ISO Filing").

course of that work I have extensively analyzed the economic impacts of minimum offer price rules in RTO/ISO capacity markets, including in public reports and affidavits submitted to FERC.

The entirety of my experience and work history can be found in my Curriculum Vitae in Attachment A.

II. Introduction

I have been asked by Clean Energy and Consumer Advocates to evaluate ISO New England's proposed tariff revisions submitted pursuant to Section 205 in the above-listed docket, specifically with regard to its proposed reform of the minimum offer price rule ("MOPR") to exclude application of the MOPR to state policy resources, including ISO-NE's proposed two-year transition mechanism. I have analyzed the potential economic impacts both from the transition mechanism as well as from ISO-NE's current tariff rules were such MOPR reforms not implemented or further delayed. The purpose of these comments is to highlight certain evidence already in the record in this proceeding and to put that evidence in the context of FERC's existing policies and fundamental economic principles. To understand the impact of the existing tariff and proposed reform on New England customers, including those who are members of the above-listed organizations, I have estimated the cost to consumers if state-sponsored resources do not clear in CASPR's substitution auction, as has historically been the case.

III. The proposal violates FERC price-setting policies.

The proposal fails to meet FERC policy on price-setting in power markets. For rates to be just and reasonable, FERC has found that prices should be set by the interaction of supply and demand as long as market power is either absent or mitigated. This has been the general framework established by FERC and the courts since electricity competition began in the early

1990s.[2,3,4] In the ISO's proposal, many supply sources are effectively excluded from participation in the capacity market for Forward Capacity Auctions ("FCA") 17 and FCA 18 because the supply bids of resources procured pursuant to state policies are subject to the MOPR in the initial auction, are likely to exceed the proposed Renewable Technology Resource ("RTR") exemption, and there has been no demonstration that the secondary auction would meaningfully bring them back into the market. The supply curve in the initial auction is not the true market supply curve because of the administratively raised bids. Thus, prices will not be set by the true intersection of supply and demand as has been longstanding Commission policy.

IV. Market Power is absent so there is no basis for mitigation.

FERC policy calls for prices to be set by supply and demand as long as market power is absent or has been mitigated. That requirement has led to various FERC-approved and RTO-implemented market power mitigation measures including MOPR for buyer-side market power mitigation. Here the mitigation of renewable resources from full market participation is not based on any finding or even allegation of market power.

The Commission has found in the past that renewable energy would be very unlikely to be used to exercise buyer side market power, given its lower capacity value and higher prices.[5]

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[2] *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 870 (D.C. Cir. 1993).

[3] "[I]n a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that price is close to marginal cost, such that the seller makes only a normal return on its investment." *Tejas Power Corp. v. FERC*, 908 F.2d 998, 1004 (D.C. Cir. 1990).

[4] Robert E. Gramlich, *The Role of Energy Regulation in Addressing Generation Market Power*, Environmental and Energy Law and Policy Journal, Vol 1. No. 1 (Mar. 31, 2006).

[5] *See, e.g.*, *ISO New England, Inc. & New England Power Pool Participants Comm.*, 158 FERC ¶ 61,138 at P 10 (Feb. 3, 2017).

V. FERC has traditionally allowed public policies to affect prices, as should be expected.

Prices have been deemed just and reasonable even when public policies affected them. A wide range of state and federal policies have affected quantities and prices in power markets since the inception of U.S. electricity markets. For example, there might not be any nuclear generation in operation were it not for the Price-Anderson Act limiting liability for unit owners. We might not have as much natural gas generation if intangible drilling costs and depletion allowances were not allowed to be deducted under federal tax law. Many states provide incentives for the production of fuels that are used in electricity generation. A large amount of generation participating in markets is part of a state regulatory rate base which affected the development of those sources and influences their ongoing behavior. Health and safety regulations affect firm behavior in electricity markets as with most other industries. Public infrastructure affects delivery costs of most products in most industries. The existence of these policies affects the amount of supply, the cost of that supply, the point at which supply and demand intersect, and the resulting price.

FERC's regulatory framework has been to set market rules in a manner that accounts for public policies in the same way as other exogenous factors that impact markets. Historically, the basic framework of treating public policies like other exogenous factors had generally held true since the establishment of organized wholesale markets. FERC's recent grand expansion of state policy mitigation policies in Northeast capacity markets that administratively set prices for gigawatts of supply, solely because those units are affected by one particular exogenous factor, represents a significant change in policy.

Just like any cost of production, a public policy is something that can affect a seller's willingness to accept or a buyer's willingness to pay. Quite directly, some generation owners must purchase sulfur dioxide allowances through EPA-regulated markets (that have existed for as long as power markets), and those suppliers may reflect the cost of such allowances in their sales or bid prices. Air emission regulations can affect allowable generation run times. Some policies may tend to raise certain suppliers' bids and/or prices such as emissions allowances, and others may tend to decrease bids and/or prices, such as renewable energy incentives. For many years, markets have been deemed workably competitive and prices have been deemed just and reasonable by the Commission throughout the Northeast organized markets as well as the rest of the country, despite public policies affecting their outcomes.

When public policies are mitigated, deterred, or otherwise specially adjusted for by the Commission rather than accounted for in the same manner as other exogenous factors, there is no clear boundary governing when the Commission might intervene and when it might not. Policies vary in many dimensions: state vs. federal, capital cost vs. operating cost support, forms of insurance vs. direct cost support, environmental vs. economic development vs. other social objectives, forms of zoning and resource access vs. economic factors, and more. Sometimes impacts are direct and sometimes they flow indirectly from upstream sectors. Some policies such as Renewable Portfolio Standards do not pick a single technology or resource but allow a measure of competition. Determinations on which policies count as "subsidies" and how to mitigate each one are subjective and easily changed over time, providing little regulatory certainty for market participants.

VI. The proposal to delay MOPR reforms to FCA 19 raises costs for consumers and forces them to pay twice for the same capacity

As the Commission found in the 2018 order accepting the CASPR proposal, Minimum Offer Price Rules can make consumers pay twice for capacity."[6] ISO-NE's Tariff filing recognizes this problem—which it refers to as "inefficient overbuild"[7]—and acknowledges that the impact on consumers in New England from applying the MOPR to state policy resources is not sustainable.[8] Yet the ISO also asserts, without support, that "there is no evidence that" consumers have been harmed by keeping state resources out of the FCM has caused consumers harm and claims, without support, that its proposal to delay MOPR reforms for two years will prevent harms to New England consumers and investors.[9]

These claims are incorrect. By definition, every MW of lower-cost sponsored policy resources that fail to clear the FCA due to the MOPR has forced consumers to pay for unnecessary and redundant capacity. Between FCA 13 and FCA 16 alone, there have been at least 900 MW of Sponsored Policy Resources that have been prevented from clearing in the primary auction due to the MOPR, requiring consumers to pay for unnecessary capacity, and raising the clearing price paid by all consumers.[10] In Section VII, I estimate that the cost to

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[6] *ISO New England Inc.*, 162 FERC ¶ 61,205 at P 24 (2018) ("This type of overbuilding can require customers to pay twice for capacity.") ("CASPR Order").

[7] ISO-NE Filing, Transmittal Letter at 5, 21-22, 27 (Mar. 31, 2022), Accession No. 20220331-5296 ("Transmittal Letter").

[8] *Id.* at 28.

[9] *Id.* at 22.

[10] *See id.* at 27, identifying 900MW of substitution supply offers between FCA13 and FCA16. Only 54 MW of these supply offers cleared in the Substitution Auction. Resources that participate as supply in the substitution auction must be certified Sponsored Policy Resources, elected participation in the Substitution Auction, and prevented from clearing in the primary auction due to the MOPR. Other Sponsored Policy Resources that did not elect to participate in the Substitution Auction but were prevented from clearing in the primary auction due to the MOPR are not included in this total.

consumers in New England from the ISO's proposal to delay MOPR reform will be in the hundreds of millions of dollars, and could be as high as $1.35 billion (see Section VII).[11] If ISO-NE's proposed limited RTR exemptions are not approved and MOPR continues to be applied for the next five forward capacity auctions, the cost could be over $4 billion.

VII. Cost of Mitigating State Resource Policies in ISO-NE's Capacity Markets.

This section explains my estimate of the cost of mitigating state policies in New England.

a. Methodology

A cost estimate can be developed through the following method:

i. Determine the amount of capacity that would be unable to clear the capacity market due to MOPR.

- Determine the installed nameplate capacity of resources covered under New England state policies that would be unable to clear the capacity market due to MOPR.

- Multiply the installed nameplate capacity ("ICAP") of those resources by their capacity values, or the expected output contribution of a resource to meeting electricity demand during peak periods, to determine the unforced capacity ("UCAP") that would be removed from the capacity market by MOPR. This accounts for the fact that many renewable resources provide significantly lower capacity value than their nameplate capacity. Based on renewable integration studies conducted by ISO-NE and others, for this analysis solar resources were expected to provide a 50% capacity value (50% of their nameplate ICAP is accredited as UCAP), offshore wind was assumed to offer a 30% capacity value, land-based wind offers 15%, and battery storage offers 95%.[12]

ii. Determine Cost of Capacity.

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[11] The cost estimate provided in Section IX comes with an admittedly large range that chiefly reflects the large uncertainty about future capacity market policies, such as the price floors that are used for the MOPR.

[12] GE Energy, *Final Report: New England Wind Integration Study* (Dec. 5, 2010), https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf; GE Energy Consulting, *PJM Renewable Integration Study: Task 3A Part F* (Mar. 31, 2014), https://www.pjm.com/-/media/committees-groups/subcommittees/irs/postings/pjm-pris-task-3a-part-f-capacity-valuation.ashx.

- Multiply the amount of unforced capacity removed from the market due to MOPR by the cost of a new combustion turbine[13] to determine the cost of the redundant capacity consumers must pay for to replace the capacity of resources that MOPR made unable to clear the market.

b. Scenarios and results

i. ISO-NE proposed reforms and two-year delay, low estimate: ISO-NE's proposed RTR exemptions and two-year delay in removing MOPR. It is assumed that the MOPR only excludes currently contracted offshore wind from clearing the capacity market, and that the Commonwealth and Mayflower residual offshore projects are not online until FCA 18.

		ICAP MW	UCAP MW
Vineyard Wind		800	140
Revolution Wind		700	210
Mayflower Wind		800	240
Park City Wind		800	240
Mayflower Residual		400	120
Commonwealth Wind		1,200	360
Total offshore		4,700	1,310
RTR cap	FCA 17		300
RTR cap	FCA 18		400
MOPRed capacity after RTR cap	FCA 17		530
MOPRed capacity after RTR cap	FCA 18		910
Cost of redundant capacity at CT gross cone of $11.39/kW-month	FCA 17		$72,440,400
	FCA 18		$124,378,800
	Total excess cost of MOPR		$196,819,200

ii. ISO-NE proposed reforms and two-year delay, high estimate: ISO-NE's proposed RTR exemptions and two-year delay in removing MOPR. The high estimate assumes the MOPR excludes all existing and future wind, solar, and battery resources from clearing the capacity market. The Commonwealth and Mayflower residual projects are online by FCA 17 instead of FCA 18, and Rhode Island passes legislation procuring an additional

[13] Using ISO-NE's most recent assumed gross Cost of New Entry ("CONE") of $11.39/kW-month. *See* Danielle Powers, et al., *ISO-NE CONE and ORTP Analysis* (Aug. 12, 2020), https://www.iso-ne.com/static-assets/documents/2020/08/a4_a_iii_cea_presentation_cone_and_ortp_analysis.pdf.

600 MW of offshore wind by FCA 17. 1200 MW of import capacity moves forward and is subject to MOPR in FCA 17.

Offshore		ICAP	UCAP
Vineyard Wind		800	140
Revolution Wind		700	210
Mayflower Wind		800	240
Park City Wind		800	240
Mayflower Residual		400	120
Commonwealth Wind		1,200	360
RI legislation		600	180
Total offshore		5,300	1,490
Other wind and solar			
S&P estimate for region's total 2030 RPS requirement[14]		12,500	
Minus offshore		7,200	
Existing RE capacity[15]		3,794	
Needed new capacity 2022-2030		3,406	
Additions per year 2022-2030		378	
Total online by FCA 17		5,686	
Half wind @ 15% capacity value, FCA 17		2843	426
Half solar @ 50% capacity value, FCA 17		2843	1422
Total online by FCA 18		6,065	
Half wind @ 15% capacity value, FCA 18		3032	455
Half solar @ 50% capacity value, FCA 18		3032	1516
Storage			
25% success rate of 5400 MW in queue with COD before 6/2026		1350	1283
Imports			
1200 MW MOPRed in FCA 17		1200	1200
MOPRed capacity after RTR cap	FCA 17		5,521
MOPRed capacity after RTR cap	FCA 18		4,344

[14] Adam Wilson, S&P Global Market Intelligence, *New England Renewable Policies to Drive 12,500 MW of Renewable Capacity by 2030* (Jun. 15, 2020), https://www.spglobal.com/marketintelligence/en/news-insights/research/new-england-renewable-policies-to-drive-12500-mw-of-renewable-capacity-by-2030.

[15] American Clean Power Association, *Clean power state-by-state* (2021) https://cleanpower.org/facts/state-fact-sheets/.

Cost of redundant capacity at CT gross cone of $11.39/kW-month	FCA 17	$754,544,977
	FCA 18	$593,671,858
	Total excess cost of MOPR	$1,348,216,835

iii. MOPR continues through 2030-2031 (FCA 21) with no reforms, low estimate: MOPR continues for five years and ISO-NE's proposed RTR exemptions are not adopted. As in the other low estimate above, it is assumed that MOPR only excludes currently contracted offshore wind from clearing the capacity market, with the additional assumption that the Commonwealth and Mayflower residual offshore projects are not online until FCA 18.

		ICAP	UCAP
Vineyard Wind		800	140
Revolution Wind		700	210
Mayflower Wind		800	240
Park City Wind		800	240
Mayflower Residual		400	120
Commonwealth Wind		1,200	360
Total offshore		4,700	1,310
RTR cap	FCA 17		0
RTR cap	FCA 18		0
MOPRed capacity	FCA 17		830
MOPRed capacity	FCA 18		1,310
MOPRed capacity	FCA 19		1,310
MOPRed capacity	FCA 20		1,310
MOPRed capacity	FCA 21		1,310
Cost of redundant capacity at CT gross cone of $11.39/kW-month	FCA 17		$113,444,400
	FCA 18		$179,050,800
	FCA 19		$179,050,800
	FCA 20		$179,050,800
	FCA 21		$179,050,800
	Total excess cost, low estimate		$829,647,600

iv. MOPR continues through 2030-2031 (FCA 21) with no reforms, high estimate. MOPR continues for five years and ISO-NE's proposed RTR exemptions are not adopted. As in the other high estimate above, it is assumed that MOPR excludes all existing and future wind, solar, and battery resources from clearing the capacity market, the Commonwealth and Mayflower residual projects are online by FCA 17 instead of FCA 18, Rhode Island passes legislation procuring an additional 600 MW of offshore wind by FCA 17, and 1200 MW of import capacity moves forward and is subject to MOPR in all five auctions.

Offshore	ICAP	UCAP
Vineyard Wind	800	140
Revolution Wind	700	210
Mayflower Wind	800	240
Park City Wind	800	240
Mayflower Residual	400	120
Commonwealth Wind	1,200	360
RI legislation	600	180
Total offshore	5,300	1,490
Other wind and solar		
S&P estimate for region's total 2030 RPS requirement	12,500	
Minus offshore	7,200	
Existing RE capacity	3,794	
Needed new capacity 2022-2030	3,406	
Additions per year 2022-2030	378	
Total online by FCA 17	5,686	
Half wind @ 15% capacity value, FCA 17	2843	426
Half solar @ 50% capacity value, FCA 17	2843	1422
Total online by FCA 18	6,065	
Half wind @ 15% capacity value, FCA 18	3032	455
Half solar @ 50% capacity value, FCA 18	3032	1516
Total online by FCA 19	6,443	
Half wind @ 15% capacity value, FCA 18	3222	483
Half solar @ 50% capacity value, FCA 18	3222	1611
Total online by FCA 20	6,822	
Half wind @ 15% capacity value, FCA 18	3411	512
Half solar @ 50% capacity value, FCA 18	3411	1705
Total online by FCA 21	7,200	
Half wind @ 15% capacity value, FCA 18	3600	540
Half solar @ 50% capacity value, FCA 18	3600	1800
Storage		
25% success rate of 5400 MW in queue with COD before 6/2026, @ 95% capacity value	1350	1283
Imports		

1200 MW MOPRed in FCA 17-21	1200	1200
MOPRed capacity	FCA 17	5,821
MOPRed capacity	FCA 18	5,944
MOPRed capacity	FCA 19	6,067
MOPRed capacity	FCA 20	6,190
MOPRed capacity	FCA 21	6,313
Cost of redundant capacity at CT gross cone of $11.39/kW-month	FCA 17	$795,548,977
	FCA 18	$812,359,858
	FCA 19	$829,170,739
	FCA 20	$845,981,619
	FCA 21	$862,792,500
	Total excess cost, high end	$4,145,853,693

c. Conclusion

Even in a best-case scenario in which ISO-NE's proposed RTR exemptions and two-year delay are adopted, and all resources except offshore wind are able to clear the capacity market, MOPR will impose excess costs of nearly $200 million on New England ratepayers. Under a less optimistic scenario that assumes all renewable and storage resources are unable to clear the capacity market due to MOPR, consumer costs will total $1.35 billion even if ISO-NE's proposed RTR exemptions and two-year delay are accepted. If the application of MOPR to sponsored policy resources is not eliminated and MOPR continues unabated through 2030-2031, consumer costs could exceed $4.1 billion, or an average of over $800 million per year, in a worst-case scenario.

This concludes my testimony.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
	)	
ISO New England Inc.	)	**Docket No. ER22-1528**
	)	
	)	

VERIFICATION OF MICHAEL GOGGIN

Pursuant to 28 U.S.C. § 1746, I, Michael Goggin, declare under penalty of perjury under the laws of the United States of America that the statements contained in the foregoing Affidavit of Michael Goggin are true and correct to the best of my knowledge and belief.

Michael Goggin

Michael Goggin

Executed on
this 21st day of April 2022

<u>ATTACHMENT A</u>

Curriculum Vitae of Michael Goggin

Michael Goggin

Education:

Harvard University class of 2004, B.A. *cum laude* in Social Studies

- Wrote thesis “Is it Time for a Change? Science, Policy, and Climate Change”

Experience:

Grid Strategies — Vice President — February 2018-present

- Serve as an expert consultant on electricity transmission, grid integration, reliability, market, and public policy issues for environmental and clean energy industry clients
- Have testified before FERC and in over 25 state regulatory commission cases
- Wrote blueprint for electricity market reforms
- Directed analysis of transmission’s value for decarbonization and job creation
- Co-authored report on need for FERC transmission policy reform
- Crafted vision for modernizing the grid for renewable energy
- Co-authored other reports cited in the “Solving the Climate Crisis” Action Plan from the Majority Staff of the House Select Committee on the Climate Crisis

AWEA — Senior Director of Research, other titles — February 2008-February 2018

- Led team responsible for all American Wind Energy Association analysis
- Served as primary technical and economic expert for market design, transmission, grid integration, carbon policy, and other topics
- Authored regulatory filings at state (IRP and transmission siting cases), regional (ISO transmission and market design), and federal levels (FERC transmission, interconnection standard, grid integration, and market design cases; EPA carbon policy)
- Directed economic and power sector modeling to inform AWEA’s policy strategy and support advocacy positions
- Communicated with the press and policy makers about wind energy
- Authored reports to promote AWEA’s policy agenda, rebut misconceptions about wind energy, and explain complex energy topics to lay audiences
- Other titles included Electric Industry Analyst, Senior Analyst, Manager of Transmission Policy, Director of Research

Sentech, Inc. — Research Analyst — October 2005-February 2008

- Conducted economic analyses of solar, wind, geothermal, and energy storage technologies for U.S. Department of Energy officials
- Provided analytical support for DOE’s renewable energy R&D funding decisions

Union of Concerned Scientists — Clean Energy Intern — May 2005-October 2005

- Worked with the legislative and field staff to promote the inclusion of pro-renewable energy measures in the Energy Policy Act of 2005

State Public Interest Research Groups — Policy Analyst — August 2004-May 2005

- Analyzed and advocated for clean energy policies at the state and federal level

Other publications available at https://gridstrategiesllc.com/articles-2/

EXHIBIT D

Tariff Language Approved by the NEPOOL Markets Committee

Changes made since the December 2021 Markets Committee meeting are highlighted in green

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as “hereunder,” “hereto,” “hereof” and “herein” and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to “include” or “including” means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant’s Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity's right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource (ATRR) is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annual Reconfiguration Transaction is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

Asset Registration Process is the ISO business process for registering an Asset.

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration or (2) one or more storage facilities with an aggregate consumption capability of at least 1 MW.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the On-Peak Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Resource's or Seasonal Peak Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the On-Peak Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

Binary Storage DARD is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Binary Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

Capacity Base Payment is the portion of revenue received in the Forward Capacity Market as described in Section III.13.7.1 of Market Rule 1.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service (CNR Interconnection Service) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Bilateral is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 of Market Rule 1.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 of Market Rule 1.

Capacity Performance Payment Rate is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 of Market Rule 1.

Capacity Performance Score is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 of Market Rule 1.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capacity Zone Demand Curves are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset or the demand reduction capability of a Demand Response Resource.

Cluster Enabling Transmission Upgrade (CETU) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Entry Deadline has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Interconnection System Impact Study (CSIS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Clustering has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each Capacity Commitment Period, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity is capacity that has achieved FCM Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

Continuous Storage ATRR is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage DARD is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Generator Asset is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Controllable Behind-the-Meter Generation means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.
Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO in the form of credit insurance coverage.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(k) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(j) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

DDP Dispatchable Resource is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Bid Cap is $2,000/MWh.

Demand Capacity Resource means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of “unavailable” for the entire day, that day will not contribute to the quantity of Demand Reduction Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of “available,” the entire day will contribute to the quantity of Demand Reduction Offer Block-Hours.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the

Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

Dispatchable Resource is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

DRR Aggregation Zone is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

Do Not Exceed (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electric Storage Facility is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation as determined by the ISO settlement process for the Energy Market.

Energy Offer Floor is negative $150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORd) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, a Market Participant's share of Zonal Capacity Obligation from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

Existing Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Retirement Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transaction Cap is $2,000/MWh for External Transactions other than Coordinated External Transactions and $1,000/MWh for Coordinated External Transactions.

External Transaction Floor is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative $1,000/MWh for Coordinated External Transactions.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

Fast Start Generator means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Charge Rate is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Commercial Operation is defined in Section III.13.3.8 of Market Rule 1.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant’s amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $9,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource’s capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH’s percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH’s percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadvertent Energy Revenue is defined in Section III.3.2.1(o) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(p) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement", the "Small Generator Interconnection Agreement", or the "Elective Transmission Upgrade Interconnection Agreement" pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures", the "Small Generator Interconnection Procedures", or the "Elective Transmission Upgrade Interconnection Procedures" pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures (OPs) are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward

Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means a Generator Asset that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load-Side Relationship Certification is a certification described in Section III.A.21.1.3 that a Project Sponsor submits as part of the New Capacity Qualification Package or New Demand Capacity Resource Qualification Package to demonstrate that the New Capacity Resource should not be subject to buyer-side market power review.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System

Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or

Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is a value calculated as described in Section III.12.2.2 of Market Rule 1.

Maximum Consumption Limit is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A

Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Maximum Daily Consumption Limit is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

Maximum Facility Load is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

Maximum Interruptible Capacity is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

Maximum Load is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

Maximum Number of Daily Starts is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time an On-Peak Demand Resource or Seasonal Peak Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Resources or Seasonal Peak Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Resources or Seasonal Peak Demand Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Resource or Seasonal Peak Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Metered Quantity For Settlement is defined in Section III.3.2.1.1 of Market Rule 1.

Minimum Consumption Limit is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

Minimum Down Time is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Minimum Total Reserve Requirement, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Payment is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Monthly Real-Time Demand Reduction Obligation is the absolute value of a Customer’s hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer’s Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer’s hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require to be economically viable given reasonable expectations of the energy and ancillary services revenues under long-term equilibrium conditions.

Net Regional Clearing Price is described in Section III.13.7.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is described in Section III.13.1.4.1.1.1 of Market Rule 1.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.3.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the Generator Asset is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

On-Peak Demand Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4.

Passive DR Auditing Period is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.1.2 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.1.2.1 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The "Phase I Transfer Capability" is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The "Phase II Transfer Capability" is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point of Interconnection shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

Proxy De-List Bid is a type of bid used in the Forward Capacity Market.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

Rationing Minimum Limit is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which an offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Capability Audit is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

Reactive Resource is a device that dynamically adjusts reactive power output automatically in Real-Time over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Demand Reduction Obligation is defined in Section III.3.2.1(c) of Market Rule 1.

Real-Time Demand Reduction Obligation Deviation is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy

Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

Real-Time Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses). A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load. A Network Customer's Monthly Regional Network Load shall be calculated in accordance with Section II.21.2 of the OATT.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Resources are those Alternative Technology Regulation Resources, Generator Assets, and Dispatchable Asset Related Demands that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

Seasonal Peak Demand Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two or Stage Two Solution that has been identified by the ISO as the preferred Phase Two or Stage Two Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that officer.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW of maximum net output when operating at any temperature at or above zero degrees Fahrenheit, that meet the metering, interconnection and other requirements in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solar High Limit is the estimated power output (MW) of a solar Generator Asset given the Real-Time solar and weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Solar Plant Future Availability is the forecasted Real-Time High Operating Limit of a solar Generator Asset, calculated in the manner described in the ISO Operating Documents.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Sponsored Policy Resource is a New Capacity Resource that: receives a revenue source, other than revenues from ISO-administered markets, that is supported by a government-regulated rate, charge, or other regulated cost recovery mechanism, and; qualifies as a renewable, clean, zero carbon, or alternative energy resource under a renewable energy portfolio standard, clean energy standard, decarbonization or net-zero carbon standard, alternative energy portfolio standard, renewable energy goal, clean energy goal, or decarbonization or net-zero carbon goal enacted by federal or New England state statute, regulation, or executive or administrative order and as a result of which the resource receives the revenue source.

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Storage DARD is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System Operating Limit (SOL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Reserve Requirement is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve (TMSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Spinning Reserve Requirement is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Reserve Requirement, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Constraint Penalty Factors are described in Section III.1.7.5 of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Unsettled FTR Financial Assurance is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Cap is $2,000/MWh.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Wind High Limit is the estimated power output (MW) of a wind Generator Asset given the Real-Time weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Wind Plant Future Availability is the forecasted Real-Time High Operating Limit of a wind Generator Asset, calculated in the manner described in the ISO Operating Documents.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

Zonal Reserve Requirement is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

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III.13. Forward Capacity Market.

The ISO shall administer a forward market for capacity ("Forward Capacity Market") in accordance with the provisions of this Section III.13. For each one-year period from June 1 through May 31, starting with the period June 1, 2010 to May 31, 2011, for which Capacity Supply Obligations are assumed and payments are made in the Forward Capacity Market ("Capacity Commitment Period"), the ISO shall conduct a Forward Capacity Auction in accordance with the provisions of Section III.13.2 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Forward Capacity Auction, a resource must be accepted in the Forward Capacity Auction qualification process in accordance with the provisions of Section III.13.1.

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Capacity Resource or Existing Demand Capacity Resource (Section III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section III.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, New Generating Capacity Resource, New Import Capacity Resource, and New Demand Capacity Resource.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the FCM Deposit. The Lead Market Participant for a resource participating in a Forward Capacity Auction may not change in the 15 Business Days prior to, or during, that Forward Capacity Auction.

III.13.1.1. New Generating Capacity Resources.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1.

III.13.1.1.1. Definition of New Generating Capacity Resource.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Capacity Resource or Existing Demand Capacity Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A Market Participant that elects to have a resource that has previously been counted as a capacity resource participate in the Forward Capacity Auction as a New Generating Capacity Resource, must notify the ISO when the existing resource ceases to operate and the New Generating Capacity Resource commences operation. If a Market Participant with a resource that has previously been counted as a capacity resource elects, pursuant to Section III.13.3.4(a)(iii), to have the resource that has previously been counted as a capacity resource cover the Capacity Supply Obligation of a New Generating Capacity Resource and the resource that has previously been counted as a capacity resource must take an outage in order for the New Generating Capacity Resource to commence Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff), then the Market Participant must notify the ISO that the outage is for the purpose of the New Generating Capacity Resource commencing Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:

(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than $200 per kilowatt of the whole resource’s summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the Handy-Whitman Index of Public Utility Construction Costs reflecting data for the period ending January 1 of the year preceding the start of the qualification process for the relevant Forward Capacity Auction; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than $100 per kilowatt of the whole resource's summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the Handy-Whitman Index of Public Utility Construction Costs reflecting data for the period ending January 1 of the year preceding the start of the qualification process for the relevant Forward Capacity Auction.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity. The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output less than or equal to the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and

(b) will be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the Handy-Whitman Index of Public Utility Construction Costs reflecting data for the period ending January 1 of the year preceding the start of the qualification process for the relevant Forward Capacity Auction. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and in which investment in the resource was undertaken prior to reactivation.

(c) A Project Sponsor or Lead Market Participant making an election pursuant to this Section III.13.1.1.1.3 must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.1.3.A. Treatment of New Incremental Capacity and Existing Generating Capacity at the Same Generating Resource.

For incremental summer capacity seeking to participate in the Forward Capacity Auction pursuant to Section III.13.1.1.1.3 or incremental winter capacity that meets the investment thresholds in Section III.13.1.1.1.3 as applied to the resource's winter Qualified Capacity, if the incremental summer or winter capacity does not span the entire Capacity Commitment Period, then the ISO shall match the incremental summer or winter capacity with excess existing winter or summer Qualified Capacity at that same resource, as appropriate, not to exceed the Qualified Capacity of the existing portion of the resource, in order to cover the entire Capacity Commitment Period. This provision shall not apply to Intermittent Power Resources.

III.13.1.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the Handy-Whitman Index of Public Utility Construction Costs reflecting data for the period ending January 1 of the year preceding the start of the qualification process for the relevant Forward Capacity Auction. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.1.5. Treatment of Resources that are Partially New and Partially Existing.

For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.1.3 or Section III.13.1.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.1.6. Treatment of Deactivated and Retired Units.

(a) [Reserved.]

(b) A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Retirement Deadline. A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

III.13.1.1.1.7 Renewable Technology Resources.

To participate in the Forward Capacity Market as a Renewable Technology Resource, a Generating Capacity Resource or an On-Peak Demand Resource (including every Asset that is part of the On-Peak Demand Resource) must satisfy the following requirements:

(a) receive an out-of-market revenue source supported by a state- or federally-regulated rate, charge or other regulated cost recovery mechanism;

(b) qualify as a renewable or alternative energy generating resource under any New England state's mandated (either by statute or regulation) renewable or alternative energy portfolio standards as in effect on January 1, 2014, or, in states without a standard, qualify under that state's renewable energy goals as a renewable resource (either by statute or regulation) as in effect on January 1, 2014. The resource must qualify as a renewable or alternative energy generating resource in the New England state in which it is geographically located. A resource physically located in United States federal waters directly adjacent to New England state maritime boundaries and directly interconnecting to the New England system is considered to be geographically located in the state where its Point of Interconnection is located;

(c) participate in a Forward Capacity Auction for a Capacity Commitment Period beginning on or after June 1, 2018 as a New Generating Capacity Resource or New Demand Capacity Resource pursuant to Section III.13.1.1, and;

(d) has been designated for treatment as a Renewable Technology Resource pursuant to Section III.13.1.1.2.9.

An Export Bid or Administrative Export De-List Bid may not be submitted for Generating Capacity Resources that assumed a Capacity Supply Obligation by participating in a Forward Capacity Auction as a Renewable Technology Resource.

III.13.1.1.2. Qualification Process for New Generating Capacity Resources.

For a resource to qualify as a New Generating Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also have, or in the case of an Import Capacity Resource seeking to qualify with an Elective Transmission Upgrade be associated with, a valid Interconnection Request under Schedules 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the interconnection procedures described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the FCM Deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

III.13.1.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, Material Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23, or Section 4.4 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein or the New Capacity Show of Interest Form shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor’s contact information; the Project

Sponsor's ISO customer status; the date by which the project is expected to achieve Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff); the project address or location, and if relevant, asset identification number; the status of the project under the interconnection procedures described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; a general description of the project's equipment configuration, including a description of the resource technology type; a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff. In the case of a resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource that is supported by an Internal Elective Transmission Upgrade, all Queue Positions associated with the project must be submitted in the New Capacity Show of Interest Form. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period pursuant to Section III.13.1.1.2.2.1.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must achieve, prior to the close of the New Capacity Show of Interest Submission Window, control of the project site for the duration of the relevant Capacity Commitment Period, which shall be as defined in Section 4.1 of Schedule 22, Section 1.5 of Schedule 23 or Section 4.1 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve all its critical path schedule milestones no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits**. In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing**. In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders**. In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2.2(c) and that accounts for more than five percent of the total project cost. For an Import Capacity Resource associated with an Elective Transmission Upgrade that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, major components shall also include, to the extent applicable, transmission facilities and associated substation equipment.

(d) **Substantial Site Construction**. In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery**. In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing**. In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (c) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning**. In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation**. In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) and/or the date by which the Project Sponsor expects to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the New Demand Capacity Resource Qualification Package has achieved its full demand reduction value. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.1.2.2.3. Offer Information.

(a) For a New Generating Capacity Resource that does not satisfy the conditions described in Section III.A.21.1.1 based on the information submitted at the time of the New Capacity Qualification Package, and for which the Project Sponsor does not provide a Load-Side Relationship Certification described in Section III.A.21.1.3, the Project Sponsor must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and sufficient documentation and information for a buyer-side market power review pursuant to Section III.A.21.2. Such documentation and information includes all financial estimates, projected revenues, and cost projections for the project, including the project's pro-forma financing support data and anticipated out-of-market revenues (as defined in Section III.A.21.3(b)(i)). For a New Generating Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation.

A Project Sponsor that submits a Load-Side Relationship Certification as part of the New Capacity Qualification Package pursuant to Section III.13.1.1.2.2.7 must be prepared to provide both (1) the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and (2) the documentation and information described in this subsection (a), in the event that the ISO determines that the Load-Side Relationship Certification does not meet the requirements of Section III.A.21.1.3.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a Rationing Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity Resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.1.2.2.4. Capacity Commitment Period Election.

Project Sponsors shall be required to specify whether they are making the election set forth in this Section III.13.1.1.2.2.4 for each Forward Capacity Auction up to and including the auction held in February 2021 for the June 1, 2024 through May 31, 2025 Capacity Commitment Period, and no election shall be permitted thereafter.

For each Forward Capacity Auction occurring up to and including the February 2021 auction, in the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive

Capacity Commitment Periods, in whole Capacity Commitment Period increments only. For incremental capacity qualified pursuant to Section III.13.1.1.1.3.A, this election shall apply to both the incremental amount of capacity and the existing Qualified Capacity matched to the incremental capacity at the same generating resource. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity. In addition to the information described elsewhere in this Section III.13.1.1.2.2:

(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.1.3(b), and III.13.1.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource.

III.13.1.1.2.2.7. Load-Side Interests.

If the Project Sponsor seeks to demonstrate one of the qualifying circumstances described in Section III.A.21.1.3 with regard to its New Generating Capacity Resource, the Project Sponsor must provide the Load-Side Relationship Certification in the New Capacity Qualification Package.

III.13.1.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a

New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a Material Modification (as defined in Section 4.4 of Schedule 22, Section 1.5 of Schedule 23 and Section 4.4 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will (i) include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff) and (ii) exclude any existing capacity that will be retired as of the start of the same Capacity Commitment Period. Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff.

(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource's Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) or Elective Transmission Upgrade Interconnection Customer as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s) or Elective Transmission Upgrade Interconnection Customer, as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22, 23 and 25 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.

The ISO shall review a New Generating Capacity Resource's New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

(a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;

(b) whether the critical path schedule includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and

(e) whether, in the case of an Intermittent Power Resource, sufficient data for confirming the resource's claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.2. [Reserved]

III.13.1.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource shall be the summer Qualified Capacity and winter Qualified

Capacity claimed by the Project Sponsor pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6. [Reserved.]

III.13.1.1.2.7. Opportunity to Consult with Project Sponsor.

In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

III.13.1.1.2.8. Qualification Determination Notification for New Generating Capacity Resources.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

(a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;

(b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource's New Capacity Qualification Package was not accepted;

(c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);

(d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource's summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;

(e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Resource; (ii) for the notification to a Conditional Qualified New Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Resource, the Queue Position of the Conditional Qualified New Resource;

(f) if accepted for participation in the Forward Capacity Auction, the ISO's determination as to whether the New Generating Capacity Resource satisfies any of the conditions described in Section III.A.21.1 and the basis for such determination; and

(g) if accepted for participation in the Forward Capacity Auction and subject to buyer-side market power review pursuant to Section III.A.21.2, the Internal Market Monitor's determinations regarding whether the New Generating Capacity Resource's requested lowest offer price, submitted pursuant to Section III.13.1.1.2.2.3(a), must be mitigated, as described in Section III.A.21.2.3. The ISO shall not disclose to the Project Sponsor any information regarding the potential impact of any offer from the Project Sponsor on Capacity Clearing Prices.

III.13.1.1.2.9 Renewable Technology Resource Election.

A Project Sponsor or Market Participant may not elect Renewable Technology Resource treatment for the FCA associated with a Capacity Commitment Period beginning on or after June 1, 2025.

A Project Sponsor or Market Participant electing Renewable Technology Resource treatment for the FCA Qualified Capacity of a New Generating Capacity Resource or New Demand Capacity Resource shall submit a Renewable Technology Resource election form no later than two Business Days after the date on which the ISO provides qualification determination notifications pursuant to Section III.13.1.1.2.8 or Section III.13.1.4.1.1.6. Only the portion of the FCA Qualified Capacity of the resource that meets the requirements of Section III.13.1.1.1.7 is eligible for treatment as a Renewable Technology Resource.

Renewable Technology Resource elections may not be modified or withdrawn after the deadline for submission of the Renewable Technology Resource election form.

The submission of a Renewable Technology Resource election that satisfies the requirements of Section III.13.1.1.1.7 will invalidate a prior multi-year Capacity Supply Obligation and Capacity Clearing Price election for the same resource made pursuant to Section III.13.1.4.1.1.2.7 or Section III.13.1.1.2.2.4 for a Forward Capacity Auction.

III.13.1.1.2.10 Determination of Renewable Technology Resource Qualified Capacity.

(a) If the total FCA Qualified Capacity of Renewable Technology Resources exceeds the cap specified in subsections (b), (c), (d) and (e) the qualified capacity value of each resource shall be prorated by the ratio of the cap divided by the total FCA Qualified Capacity. The ISO shall notify the Project Sponsor or Market Participant, as applicable, of the Qualified Capacity value of its resource no more than five Business Days after the deadline for submitting Renewable Technology Resource elections.

(b) The cap for the Capacity Commitment Period beginning on June 1, 2018 is 200 MW.

(c) The cap for the Capacity Commitment Period beginning on June 1, 2019 is 400 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Capacity Resources pursuant to Section III.13.2 in the prior Capacity Commitment Period.

(d) The cap for each Capacity Commitment Period beginning on June 1, 2020 or June 1, 2021 is 600 MW minus the amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Capacity Resources pursuant to Section III.13.2 in the prior two Capacity Commitment Periods.

(e) The cap for each Capacity Commitment Period beginning on June 1, 2022 or June 1, 2023 or June 1, 2024 is 514 MW minus the cumulative amount of Capacity Supply Obligations acquired by Renewable Technology Resources that are New Capacity Resources in the first or second run of the primary auction-clearing process pursuant to Section III.13.2 for each Capacity Commitment Period that begins on or after June 1, 2021.

III.13.1.2. Existing Generating Capacity Resources.

An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), or as a New Demand Capacity Resource or Existing Demand Capacity Resource (Section III.13.1.4) shall be an Existing Generating Capacity Resource.

III.13.1.2.1.1. Attributes of Existing Generating Capacity Resources.

For purposes of Forward Capacity Auction qualification, a Market Participant may not change any Existing Generating Capacity Resource attribute (including but not limited to the resource's status as an Intermittent Power Resource) in the period beginning 20 Business Days prior to the Existing Capacity Retirement Deadline and ending with the conclusion of the Forward Capacity Auction. Outside of this period, any such change must be accompanied by documentation justifying the change.

III.13.1.2.1.2 Rationing Minimum Limit.

No later than 120 days before the Forward Capacity Auction Market Participants may specify a Rationing Minimum Limit for an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource had not yet achieved FCM Commercial Operation, then the Existing Generating Capacity Resource's summer

Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. Winter Qualified Capacity.

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource had not yet achieved FCM Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources.

The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that is an Intermittent Power Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource.

(a) With regard to any Forward Capacity Auction qualification process, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's net output in the Summer Intermittent Reliability Hours. If there are less than five full summer periods since the Intermittent Power Resource achieved FCM Commercial Operation, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous summer periods, or portion thereof, since the Intermittent Power Resource achieved FCM Commercial Operation.

(b) The Intermittent Power Resource's summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which there was a system-wide Capacity Scarcity Condition and if the Intermittent Power Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource had not yet achieved FCM Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource.

(a) With regard to any Forward Capacity Auction qualification process, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource's net output in the Winter Intermittent Reliability Hours. If there are less than five full winter periods since the Intermittent Power Resource achieved FCM Commercial Operation, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous winter periods, or portion thereof, since the Intermittent Power Resource achieved FCM Commercial Operation.

(b) The Intermittent Power Resource's winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.2(a).

(c) The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which there was a system-wide Capacity Scarcity Condition and if the Intermittent Power Resource was in an import-constrained Capacity Zone, all Capacity Scarcity Conditions in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource had not yet achieved FCM Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

(a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves FCM Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves FCM Commercial Operation, the Existing Generating Capacity Resource's summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource's FCM Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves FCM Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves FCM Commercial Operation, the Existing Generating Capacity Resource's winter Qualified

Capacity shall be calculated as described in Section III.13.1.2.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource's FCM Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Retirement Deadline.

Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource (other than a Settlement Only Resource or an Intermittent Power Resource) is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, by:

(1) for Capacity Commitment Periods beginning prior to June 1, 2023, more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW;

(2) for Capacity Commitment Periods beginning on or after June 1, 2023, more than the lesser of:

(i) the greater of 10 percent of that summer Qualified Capacity or two MW, or;

(ii) 10 MW;

then the Lead Market Participant must elect one of the two treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Retirement Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) [Reserved.]

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section III.13.1.2.2.1.1 by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section III.13.1.2.2.1.1 for the Forward

Capacity Auction. For an Existing Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource (other than a Settlement Only Resource) meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource's summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than the close of the New Capacity Show of Interest Submission Window. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction meets the requirements of this Section, but the incremental amount of capacity does not span the entire Capacity Commitment Period, then the ISO shall match the incremental amount of capacity with excess Qualified Capacity at that same resource, not to exceed the Qualified Capacity of the existing portion of the resource, in order to cover the entire Capacity Commitment Period. This provision shall not apply to Intermittent Power Resources.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Capacity Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Capacity Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource) has a summer Qualified Capacity that exceeds its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

(a) For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Retirement Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located.

(b) If the Lead Market Participant believes that the ISO has made a mathematical error in calculating the summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource as described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within five Business Days of receipt of the Qualified Capacity notification.

(c) The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than five Business Days before the Existing Capacity Retirement Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, a Permanent De-List Bid, or a Retirement De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Retirement Package and Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Retirement Deadline, as described in Section III.13.1.1.1.6(b). All Permanent De-List Bids and Retirement De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline. All Static De-List Bids, Export Bids and Administrative Export De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline. Permanent De-List Bids and Retirement De-List Bids may not be modified or withdrawn after the Existing Capacity Retirement Deadline, except as provided for in Section III.13.1.2.4.1. All Static De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, except as provided for in

Section III.13.1.2.3.1.1. An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Permanent De-List Bid, or Retirement De-List Bid for an amount of capacity greater than its summer Qualified Capacity, unless the submittal is for the entire resource. Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; neither a Permanent De-List Bid nor a Retirement De-List Bid may be combined with any other type of de-list or export bid.

Static De-List Bids and Export Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

For the fifteenth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2024), the Dynamic De-List Bid Threshold is $4.30/kW-month. For each Forward Capacity Auction thereafter, the Dynamic De-List Bid Threshold shall be calculated as described below in this Section III.13.1.2.3.1.A, and shall be published to the ISO's website no later than 5 Business Days before the Existing Capacity Retirement Deadline. This publication shall include the preliminary value calculated pursuant to subsection (a) below, whether the preliminary value was constrained by either of the limitations described in subsection (b) below, the margin value as calculated pursuant to subsection (c) below, and the final value as calculated pursuant to subsection (d) below.

(a) Subject to the limitations described in subsection (b) below, a preliminary value of the Dynamic De-List Bid Threshold shall be calculated as the average of: (i) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone from the immediately preceding Forward Capacity Auction (provided, however, that if there is a second run of the primary auction-clearing process pursuant to Section III.13.2.5.2.1(d), the resulting Rest-of-Pool Capacity Zone clearing price from that run shall be used instead); and (ii) the price at which the total amount of capacity clearing in the immediately preceding Forward Capacity Auction intersects the estimated System-Wide Capacity Demand Curve for the upcoming Forward Capacity Auction. For this purpose, the estimated System-Wide Capacity Demand Curve shall be constructed, in the same manner as described in Section III.13.2.2.1, using the system-wide Marginal Reliability Impact values from the immediately preceding Forward Capacity Auction, the most recent estimate of the Installed Capacity Requirement (net of HQICCs) for the upcoming Forward Capacity Auction, and the Net CONE and Forward Capacity Auction Starting Price for the upcoming Forward Capacity Auction.

(b) The preliminary value of the Dynamic De-List Bid Threshold shall not be higher than 75 percent of the Net CONE value for the upcoming Forward Capacity Auction. The preliminary value of the Dynamic De-List Bid Threshold shall not be lower than 75 percent of the clearing price applicable pursuant to (a)(i) of this Section III.13.1.2.3.1.A, except as needed to ensure that it is not higher than 75 percent of the Net CONE value for the upcoming Forward Capacity Auction.

(c) A margin value shall be calculated using the following formula:

$$Margin\ = \$1/kW\text{-}month\ \times \left[\frac{\left(75\%\ \times\ Net\ CONE_{upcoming\ FCA}\right) - DDBT_{preliminary}}{\left(75\%\ \times\ Net\ CONE_{upcoming\ FCA}\right)}\right]$$

(d) The final value of the Dynamic De-List Bid Threshold for the upcoming Forward Capacity Auction shall be equal to the preliminary value of the Dynamic De-List Bid Threshold calculated pursuant to Sections III.13.1.2.3.1.A(a) and III.13.1.2.3.1.A(b) plus the margin value calculated pursuant to Section III.13.1.2.3.1.A(c).

III.13.1.2.3.1.1. Static De-List Bids.

A Lead Market Participant with an Existing Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation for that resource, or a portion thereof, at prices at or above the Dynamic De-List Bid Threshold during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction qualification process. A Static De-List Bid may not result in a resource’s Capacity Supply Obligation being less than its Rationing Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs). The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Lead Market Participant must notify the ISO if the Existing Capacity Resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests).

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b), a Lead Market Participant that submitted a Static De-List Bid may: (a) lower the price of any price-quantity pair of a Static De-List Bid, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or; (b) withdraw any price-quantity pair of a Static De-List Bid.

III.13.1.2.3.1.2. [Reserved.]

III.13.1.2.3.1.3. Export Bids.

An Existing Generating Capacity Resource within the New England Control Area, other than an Intermittent Power Resource or a Renewable Technology Resource, seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction qualification process. An Export Bid may not result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids at or above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource or a Renewable Technology Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction qualification process. An Administrative Export De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity Commitment Period. Administrative Export De-List Bids shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.5.2.4.

III.13.1.2.3.1.5. Permanent De-List Bids and Retirement De-List Bids.

(a) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would not accept a Capacity Supply Obligation permanently for all or part of a Generating Capacity Resource beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction qualification process.

(b) A Lead Market Participant with an Existing Capacity Resource seeking to specify a price at or below which it would retire all or part of a Generating Capacity Resource from all New England Markets beginning at the start of a particular Capacity Commitment Period may submit a Retirement De-List Bid in the associated Forward Capacity Auction qualification process.

(c) No Permanent De-List Bid or Retirement De-List Bid may result in a resource's Capacity Supply Obligation being less than its Rationing Minimum Limit unless the Permanent De-List Bid or Retirement De-List Bid is for the entire resource. Each Permanent De-List Bid and Retirement De-List Bid must be detailed in an Existing Capacity Retirement Package submitted to the ISO no later than the Existing Capacity Retirement Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Permanent De-List Bids and Retirement De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2.1 and must include the additional documentation described in that section. Once submitted, no Permanent De-List Bid or Retirement De-List Bid may be withdrawn, except as provided in Section III.13.1.2.4.1.

III.13.1.2.3.1.5.1. Reliability Review of Permanent De-List Bids and Retirement De-List Bids During the Qualification Process.

During the qualification process, the ISO will review the following de-list bids to determine if the resource is needed for reliability: (1) Internal Market Monitor-accepted Permanent De-List Bids and Internal Market Monitor-accepted Retirement De-List Bids that are at or above the Forward Capacity Auction Starting Price; and (2) Permanent De-List Bids and Retirement De-List Bids for which the Lead Market Participant has opted to have the resource reviewed for reliability as described in Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b). The reliability review will be conducted according to Section III.13.2.5.2.5, except as follows:

(a) Permanent De-List Bids and Retirement De-List Bids that cannot be priced (for example, due to the expiration of an operating license) will be reviewed first.

(b) System needs associated with Permanent De-List Bids and Retirement De-List Bids for resources found needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1 will be reviewed with the Reliability Committee during the month of August following the issuance of retirement determination notifications pursuant to Section III.13.1.2.4(a). The Lead Market Participant shall be notified as soon as practicable following the ISO's consultation with the Reliability Committee that the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons.

(c) If the capacity associated with a Permanent De-List Bid or Retirement De-List Bid is needed for reliability reasons pursuant to this Section III.13.1.2.3.1.5.1, the de-list bid shall be rejected and the resource shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(c) and compensated according to Section III.13.2.5.2.5, unless the resource declines to be retained for reliability, as provided in Section III.13.1.2.3.1.5.1(d).

(d) No later than the fifth Business Day in the month of September following the review of system needs with the Reliability Committee per (b) above, a Lead Market Participant may notify the ISO that it declines to provide the associated capacity for reliability. Such an election will be binding. A resource for which a Lead Market Participant has made such an election will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2.

(e) Where a resource is determined not to be needed for reliability or where a Lead Market Participant notifies the ISO that it declines to provide capacity for reliability pursuant to Section III.13.1.2.3.1.5.1(d), the capacity associated with the Permanent De-List Bid or Retirement De-List Bid will be treated as follows:

> (i) For a Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected to retire the resource pursuant to Section III.13.1.2.4.1(a), the portion of the resource subject to the de-list bid will be retired as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(a).
>
> (ii) For a Permanent De-List Bid at or above the Forward Capacity Auction Starting Price for which a Lead Market Participant has not elected to retire the resource pursuant to Section III.13.1.2.4.1(a), the portion of the resource subject to the de-list bid will be permanently de-listed coincident with the commencement of the Capacity Commitment Period for which the de-list bid was submitted, as described in Section III.13.2.5.2.5.3(b).

(iii) For a Permanent De-List Bid or Retirement De-List Bid for which a Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the de-list bid will continue to receive conditional treatment as described in Section III.13.1.2.4.1(b), Section III.13.2.3.2(b)(ii), and Section III.13.2.5.2.1.

III.13.1.2.3.1.6. Static De-List Bids, Permanent De-List Bids and Retirement De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids, Permanent De-List Bids, or Retirement De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1. Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids, Permanent De-List Bids, or Retirement De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

III.13.1.2.3.1.6.2. [Reserved.]

III.13.1.2.3.1.6.3. Internal Market Monitor Review of Stations having Common Costs.

The Internal Market Monitor will review each Static De-List Bid, Permanent De-List Bid and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

(i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.

(ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred de-list order.

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive de-listing of each individual asset in preferred de-list order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of bids as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The bids of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable bid for use in the Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will establish an Internal Market Monitor-determined or Internal Market Monitor– accepted price for the bid as described in Section III.13.1.2.3.2.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Capacity Resources.

The Internal Market Monitor shall review bids for Existing Capacity Resources as follows.

III.13.1.2.3.2.1. Static De-List Bids and Export Bids, Permanent De-List Bids, and Retirement De-List Bids at or Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid and each Export Bid at or above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the Existing Capacity

Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2.A); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); (3) reasonable risk premium assumptions (as determined pursuant to Section III.13.1.2.3.2.1.4); and (4) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5).

The Internal Market Monitor shall review each Permanent De-List Bid greater than 20 MW that is at or above the Dynamic De-List Bid Threshold and each Retirement De-List Bid greater than 20 MW that is at or above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the net present value of the resource's expected cash flows (as determined pursuant to Section III.13.1.2.3.2.1.2.B); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); and (3) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). If more than one Permanent De-List Bid or Retirement De-List Bid is submitted by a single Lead Market Participant or its Affiliates (as used in Section III.A.24), the Internal Market Monitor shall review each such bid at or above the Dynamic De-List Bid Threshold if the sum of all such bids at or above the Dynamic De-List Bid Threshold is greater than 20 MW. The Internal Market Monitor shall review each Permanent De-List Bid and each Retirement De-List Bid submitted at any price pursuant to Section III.13.2.5.2.1(b) if the sum of the Permanent De-List Bids and Retirement De-List Bids submitted by the Lead Market Participant or its Affiliates (as used in Section III.A.24) is greater than 20 MW. Permanent De-List Bids and Retirement De-List Bids that are not reviewed by the Internal Market Monitor shall be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

Sufficient documentation and information about each bid component must be included in the Existing Capacity Retirement Package or the Existing Capacity Qualification Package to allow the Internal Market Monitor to make the requisite determinations. If a Permanent De-List Bid or Retirement De-List Bid is submitted pursuant to Section III.13.2.5.2.1(b), all relevant updates to previously submitted documentation and information must be provided to support the newly submitted price and allow the Internal Market Monitor to make updated determinations. The updated information may include a request to discontinue the Permanent De-List Bid or Retirement De-List Bid such that it will not be entered into the Forward Capacity Auction, in which case the update must include sufficient supporting information on the nature of resource investments that were undertaken, or other materially changed circumstances, to allow the Internal Market Monitor to determine whether discontinuation is appropriate.

The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of its content, including reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments, cash flows, opportunity costs, and risk premiums, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.

The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the other existing or potential new resources controlled by the Lead Market Participant) after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate. The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. In making this determination, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

III.13.1.2.3.2.1.1.1. Review of Static De-List Bids and Export Bids.

The Internal Market Monitor shall review Static De-List Bids and Export Bids and, after due consideration and consultation with the Lead Market Participant, as appropriate, shall develop an Internal Market Monitor-accepted Static De-List Bid or an Internal Market Monitor-accepted Export Bid. The Internal Market Monitor-accepted Static De-List Bid and Internal Market Monitor-accepted Export Bid shall be equal to the Static De-List Bid or Export Bid submitted by the Lead Market Participant unless the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s) for the same de-list bid. If the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s), the Internal Market Monitor shall calculate an Internal Market Monitor-accepted Static De-List Bid or Internal Market-Monitor-accepted Export Bid that is consistent with the sum of the resource's net going forward costs plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable risk premium assumptions plus reasonable opportunity costs.

If an Internal Market Monitor-determined price is established for a Static De-List Bid or an Export Bid, both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(c) shall include an explanation of the Internal Market Monitor-determined price based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor.

III.13.1.2.3.2.1.1.2. Review of Permanent De-List Bids and Retirement De-List Bids.
The Internal Market Monitor shall review those Permanent De-List Bids and Retirement De-List Bids identified in Section III.13.1.2.3.2.1 and, after due consideration and consultation with the Lead Market Participant, as appropriate, shall develop an Internal Market Monitor-accepted Permanent De-List Bid or an Internal Market Monitor-accepted Retirement De-List Bid. The Internal Market Monitor-accepted Permanent De-List Bid and Internal Market Monitor-accepted Retirement De-List Bid shall be equal to the Permanent De-List Bid or Retirement De-List Bid submitted by the Lead Market Participant unless the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s) for the same de-list bid. If the de-list bid price(s) submitted by the Lead Market Participant are more than 10% greater than the Internal Market Monitor-accepted de-list bid price(s), the Internal Market Monitor shall calculate an Internal Market Monitor-accepted Permanent De-List Bid or Internal Market-Monitor-accepted Retirement De-List Bid that is consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The retirement determination notification described in Section III.13.1.2.4(a) and the filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the Internal Market Monitor-accepted price and the Internal Market Monitor determination on any request to discontinue the Permanent De-List Bid or Retirement De-List Bid.

III.13.1.2.3.2.1.2.A. Static De-List Bid and Export Bid Net Going Forward Costs.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an Export Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report expected net going forward costs for the applicable Capacity Commitment Period in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. A Static De-List Bid or Export Bid at or above the Dynamic De-List Bid Threshold shall be considered consistent with the Existing Capacity Resource's net going forward costs based on a review of the data submitted in the following formula.

$$\textit{Net Going Forward Costs} = \frac{(GFC - IMR) \times InfIndex}{(CQ_{Summer,}\, kw) \times (12\ months)}$$

Where:

GFC = annual going forward costs, in dollars. These are the expected costs and capital expenditures that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a resource with a Capacity Supply Obligation during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period.

$CQ_{Summer}kW$ = capacity seeking to de-list in kW. In no case shall this value exceed the resource's summer Qualified Capacity.

IMR = expected annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be calculated by subtracting all submitted cost data representing the cumulative expected cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00.

InfIndex = inflation index. infIndex = $(1 + i)^4$

Where: "*i*" is the most recent reported 4- Year expected inflation number published by the Federal Reserve Bank of Cleveland at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.2.B Permanent De-List Bid and Retirement De-List Bid Net Present Value of Expected Cash Flows.

The Lead Market Participant for an Existing Capacity Resource that submits a Permanent De-List Bid or Retirement De-List Bid that is to be reviewed by the Internal Market Monitor shall report all expected costs, revenues, prices, discount rates and capital expenditures in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. The Internal Market Monitor will review the Lead Market Participant's submitted data to ensure that it is consistent with overall market conditions and reflects expected values.

The Internal Market Monitor will adjust any data that are inconsistent with overall market conditions or do not reflect expected values. The Internal Market Monitor shall enter all relevant expected costs, revenues, prices, discount rates and capital expenditures into a capital budgeting model and shall determine the net present value of the Existing Capacity Resource's expected cash flows as follows:

The net present value of the Existing Capacity Resource's expected cash flows is equal to (i) the net present value of the Existing Capacity Resource's net annual expected cash flows over the resource's remaining economic life (as determined pursuant to Section III.13.1.2.3.2.1.2.C) plus the net present value of the resource's expected terminal value, using the resource's discount rate, divided by (ii) the product of the resource's Qualified Capacity (in kilowatts) and12 months.

The Existing Capacity Resource’s net annual expected cash flow for the first Capacity Commitment Period of the resource’s remaining economic life is the resource’s expected annual net operating profit excluding expected capacity revenues less its expected capital expenditures in the Capacity Commitment Period.

The Existing Capacity Resource’s net annual expected cash flow for each of the subsequent Capacity Commitment Periods of the resource’s remaining economic life is the resource’s expected annual net operating profit less its expected capital expenditures in the Capacity Commitment Period.

Where:

Expected net operating profit, in dollars, is the Lead Market Participant’s expected annual profit that might otherwise be avoided or not accrued if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period. Expected labor, maintenance, taxes, insurance, administrative and other normal expenses that can be avoided or not incurred if the resource is retired or permanently de-listed may be included. Service of debt is not an avoidable cost and may not be included.

Expected capacity revenues, in dollars, are the forecasted annual expected capacity revenues based on the Lead Market Participant’s forecasted expected capacity prices for each of the subsequent Capacity Commitment Periods of the resource’s remaining economic life. The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the forecasted expected capacity prices. The supporting documentation must include a detailed description and sources of the Lead Market Participant’s assumptions about expected resource additions, resource retirements, estimated Installed Capacity Requirements, estimated Local Sourcing Requirements, expected market conditions, and any other assumptions used to develop the forecasted expected capacity price in each Capacity Commitment Period.

If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the forecasted expected capacity prices, the Internal Market Monitor will replace the Lead Market Participant’s forecasted expected capacity prices with the Internal Market Monitor’s estimate thereof in each of the subsequent Capacity Commitment Periods of the resource’s remaining economic life.

Expected capital expenditures, in dollars, are the Lead Market Participant's expected capital investments that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Periods.

Expected terminal value, in dollars, for resources with five years or less of remaining economic life, is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource. For resources with more than five years of remaining economic life, the expected terminal value in the fifth year of the evaluation period is the Lead Market Participant's expected revenue less expected costs associated with retiring or permanently de-listing the resource at the end of the resource's economic life plus the net present value of the Existing Capacity Resource's net annual expected cash flows from the sixth year of the evaluation period through the end of the resource's remaining economic life, using the resource's discount rate.

Discount rate is a value reflecting the Lead Market Participant's weighted average cost of capital for the Existing Capacity Resource adjusted to reflect the risk to cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B.

The Lead Market Participant shall provide the Internal Market Monitor with documentation supporting the weighted average cost of capital for the Existing Capacity Resource adjusted for risk.
The supporting documentation must include a detailed description and sources of the Lead Market Participant's assumptions associated with the cost of capital, risks and any other assumptions used to develop the weighted average cost of capital for the Existing Capacity Resource adjusted for risk.
If the Internal Market Monitor determines the Lead Market Participant has not provided adequate supporting documentation for the weighted average cost of capital for the Existing Capacity Resource adjusted for risk, the Lead Market Participant has included risks not associated with cash flows calculated pursuant to the net present value of expected cash flows analysis in this Section III.13.1.2.3.2.1.2.B or the Lead Market Participant has submitted costs, revenues, capital expenditures or prices that are not reflective of expected values, the Internal Market Monitor will replace the Lead Market Participant's discount rate with a value determined by the Internal Market Monitor.

III.13.1.2.3.2.1.2.C Permanent De-List Bid and Retirement De-List Bid Calculation of Remaining Economic Life.

The Internal Market Monitor shall calculate the Existing Capacity Resource's remaining economic life, using evaluation periods ranging from one to five years. For each evaluation period, the Internal Market Monitor will calculate the net present value of (a) the annual expected net operating profit minus annual expected capital expenditures assuming the Capacity Clearing Price for the first year is equal to the Forward Capacity Auction Starting Price and (b) the expected terminal value of the resource at the end of the given evaluation period. The economic life is the maximum evaluation period in which a resource's net present value is non-negative. However, effective April 9, 2020, beginning with the sixteenth Forward Capacity Auction, the economic life is the evaluation period in which a resource's net present value is maximized.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an Export Bid, Permanent De-List Bid, or Retirement De-List Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.13.1.2.3.2.1.4. Risk Premium.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid, or an Export Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing any risk premium included in the bid. This documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.13.1.2.3.2.1.2.A may be included in this risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the Forward Capacity Market is consistent with the participant's corporate risk management practices.

III.13.1.2.3.2.1.5. Opportunity Costs.

To the extent that an Existing Capacity Resource submitting a Static De-List Bid or an Export Bid, Permanent De-List Bid or Retirement De-List Bid at or above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, net present value of expected cash flows, expected Capacity Performance Payments, discount rate, or risk premium components of the bid, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.13.1.2.3.2.2. [Reserved.]

III.13.1.2.3.2.3. Administrative Export De-List Bids.

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. Static De-List Bid Incremental Capital Expenditure Recovery Schedule. Except as described below, the Internal Market Monitor shall review all Static De-List Bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

Age of Existing Resource (years)	**Remaining Life (years)**	**Annual Rate of Capital Cost Recovery**
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource's annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{\textit{Cost Of Capital}}{(1-(\mathbf{1}+\textit{CostOfCapital})^{-\textit{RemainingLife}})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Retirement Determination Notification for Existing Capacity and Qualification Determination Notification for Existing Capacity; Right to Increase Retirement De-List Bid or Permanent De-List Bid up to IMM-determined substitution auction test price.

(a) No later than five Business Days before the Existing Capacity Qualification Deadline, the ISO shall send notification to the Lead Market Participant that submitted each Permanent De-List Bid, Retirement De-List Bid and substitution auction test price concerning the result of the Internal Market Monitor's review conducted pursuant to Section III.13.1.2.3.2 and Section III.13.2.8.3.1A. This retirement determination notification shall not include the results of the reliability review pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5. For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, within five Business Days of the issuance of the retirement determination notification, a Lead Market Participant that submitted a Retirement De-List Bid or a Permanent De-List Bid and a substitution auction demand bid for the resource associated with the de-list bid, may make the following adjustments:

(i) for a Retirement De-List Bid, if, but for the limits in Section III.13.1.2.3.2.1.1.2 on adjusting a Market Participant-submitted Retirement De-List Bid, the Internal Market Monitor would have calculated a Retirement De-List Bid price that is higher than the Market Participant-submitted de-list bid price and the Market Participant-submitted de-list bid is less than the Internal Market Monitor-determined substitution auction test price multiplied by 0.9, the Market Participant may increase the de-list bid price up to the minimum of (x) the Internal Market Monitor-determined substitution auction test price multiplied by 0.9 and (y) the higher Retirement De-List Bid price that the Internal Market Monitor would have calculated;

(ii) for a Permanent De-List Bid, if, but for the limits in Section III.13.1.2.3.2.1.1.2 on adjusting a Market Participant-submitted Permanent De-List Bid, the Internal Market Monitor would have calculated a Permanent De-List Bid price that is higher than the Market Participant-submitted de-list bid price and the Market Participant-submitted de-list bid is less than the Internal Market Monitor-determined substitution auction test price multiplied by 0.9, the Market Participant may increase the de-list bid price up to the minimum of (x) the Internal Market Monitor-determined substitution auction test price multiplied by 0.9 and (y) the higher Permanent De-List Bid price that the Internal Market Monitor would have calculated.

(b) No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid and Export Bid concerning the result of the Internal Market Monitor's de-list bid review conducted pursuant to Section III.13.1.2.3.2. The qualification determination shall not include the results of the reliability review pursuant to Section III.13.2.5.2.5.

III.13.1.2.4.1. Participant-Elected Retirement or Conditional Treatment.

No later than five Business Days after the issuance by the ISO of the retirement determination notification described in Section III.13.1.2.4(a), a Lead Market Participant that submitted a Permanent De-List Bid or Retirement De-List Bid may make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b). If the Lead Market Participant does not make an election pursuant to Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b), the prices provided by the Internal Market Monitor in the retirement determination notifications shall be the finalized prices used in the Forward Capacity Auction as described in Section III.13.2.3.2(b) (unless otherwise directed by the Commission).

(a) A Lead Market Participant may elect to retire the resource, or portion thereof, for which it has submitted a Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will not be subject to reliability review and will be retired pursuant to Section III.13.2.5.2.5.3(a); provided, however, that when making the retirement election pursuant to this Section III.13.1.2.4.1(a) the Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

(b) A Lead Market Participant may elect conditional treatment for the Permanent De-List Bid or Retirement De-List Bid. The capacity associated with a Permanent De-List Bid or Retirement De-List Bid subject to this election will be treated as described in Section III.13.2.3.2(b)(ii), Section III.13.2.5.2.1, and Section III.13.2.5.2.5.3; provided, however, that in making this election the Lead Market Participant may opt to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1, in which case the Lead Market Participant may have the opportunity (but will not be obligated) to provide capacity from the resource if the ISO determines that the resource is needed for reliability reasons, as described in Section III.13.1.2.3.1.5.1(d).

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external demand resource may not be an Existing Import Capacity Resource or a New Import Capacity Resource. External nodes shall be established and mapped to Capacity Zones pursuant to the provisions in Attachment K to Section II of the Transmission, Markets and Services Tariff.

An Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be included in the FCM (1) after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Forward Capacity Market qualification requirements or (2) after it has met the requirements of an Elective Transmission Upgrade with Long

Lead Time Facility treatment pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff. An external node for such an Elective Transmission Upgrade will be modeled for participation in the Forward Capacity Market after the Import Capacity Resource meets the requirements to participate in the FCA. The Qualified Capacity of an Import Capacity Resource associated with an Elective Transmission Upgrade shall not exceed the Capacity Network Import Interconnection Service Interconnection Request. In order for an Elective Transmission Upgrade to maintain its Capacity Network Import Interconnection Service, an associated Import Capacity Resource must meet the Forward Capacity Market qualification requirements and offer into each Forward Capacity Auction. Otherwise, the Capacity Network Import Interconnection Service will revert to Network Import Interconnection Service for the portion of the Capacity Network Import Interconnection Service for which no Import Capacity Resource is offered into the Forward Capacity Auction and the Elective Transmission Upgrade's Interconnection Agreement will be revised. The provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election, shall apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade seeking to reestablish Capacity Network Import Interconnection Service if the threshold to be treated as a new resource in Section III.13.1.1.1.4 is met. If the threshold to be treated as a new increment in Section III.13.1.1.1.3 is met, only the increment will be eligible for the provisions in Sections III.13.1.3.5.4, permitting a Capacity Commitment Period Election, and in Section III.13.1.3.5.8, permitting a rationing election.

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Retirement Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. Qualified Capacity for Existing Import Capacity Resources.

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3.A(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3.A(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3.A Qualification Process for Existing Import Capacity Resources that are not associated with an Elective Transmission Upgrade with Capacity Network Import Interconnection Service.

Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

(a) The Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply.

(c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3A for the duration of the contracts as listed. For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3A, no later than 10 Business Days prior to the Existing Capacity Retirement Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3A.

Contract Description	MW	Contract End Date

NYPA: NY ─ NE: CMEEC	13.2	8/31/2025
NYPA: NY ─ NE: MMWEC	53.3	8/31/2025
NYPA: NY ─ NE: Pascoag	2.3	8/31/2025
NYPA: NY─ NE: VELCO	15.3	8/31/2025
	84.1	
VJO: Highgate ─ NE	Up to 225	10/31/2016
VJO: Highgate ─ NE (extension) (beginning 11/01/2016)	Up to 6	October 2020
VJO: Phase I/II ─ NE	Up to 110	10/31/2016

(d) In addition to the review described in Section III.13.1.2.3.2, the Internal Market Monitor shall review each bid from Existing Import Capacity Resources. A bid from an Existing Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.3.B. Qualification Process for Existing Import Capacity Resources that are associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service. Existing Import Capacity Resources associated with an Elective Transmission Upgrade with Capacity Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be subject to the same qualification process as Existing Generating Capacity Resources as described in Section III.13.1.2.3, except the Qualified Capacity shall be the lesser of the multi-year contract values as documented in the new resource qualification determination notification and the capacity clearing in the Forward Capacity Auction to which the new resource qualification determination notification applied.

III.13.1.3.4. Definition of New Import Capacity Resource.

Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification

Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.

(a) For each New Import Capacity Resource, the Project Sponsor submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the contract period including the entire Capacity Commitment Period, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iv) documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load. For each New Import Capacity Resource, the Project Sponsor must specify the interface over which the capacity will be imported. The Project Sponsor must indicate whether the import is associated with any investment in transmission that increases New England's import capability or is associated with an Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services

Tariff that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff. The Project Sponsor must submit a contract confirming its association with the Elective Transmission Upgrade Interconnection Customer and the ISO will confirm that relationship. If the import will be backed by a single new External Resource, the Project Sponsor submitting the import capacity must also submit a general description of the project's equipment configuration, including a description of the resource technology type.

(b) To qualify for Capacity Commitment Periods prior to the Capacity Commitment Period associated with the Forward Capacity Auction for which the import capacity is qualifying, the Project Sponsor must submit documentation of one or more one-year contracts for each prior Capacity Commitment Period, entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract(s); the Project Sponsor must also satisfy the relevant requirements of Sections III.13.1.3.5.1(a) , III.13.1.3.5.2, III.13.1.9, and III.13.3.1.1.

III.13.1.3.5.2. Import Backed by Existing External Resources.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Project Sponsor shall instead submit a description of how the New Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall apply in addition to the requirement that the Project Sponsor submit a description of how the New Import Capacity Resource will meet its Capacity Supply Obligation in the Capacity Commitment Period(s) for which it seeks to qualify.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the Project Sponsor, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the New Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.

If the New Import Capacity Resource will be backed by an external Control Area and the capacity will be imported over an interface that has achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Project Sponsor shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

If the New Import Capacity Resource will be backed by an external Control Area and the capacity will be imported over an Elective Transmission Upgrade and the capacity will be imported over an interface that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall apply in addition to the requirement that the Project Sponsor submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource for the length of the multi-year contract.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.

The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) For imports crossing a single intervening Control Area, the Project Sponsor entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing. (2) For imports crossing more than one intervening Control Area, in addition to the requirements above, the Project Sponsor entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load. (3) The Project Sponsor entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.13.1.3.5.4. Capacity Commitment Period Election.

The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall only apply to a New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request. All other New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction.

III.13.1.3.5.5. Initial Interconnection Analysis.

The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply unless the capacity will be imported over an Elective Transmission Upgrade pursuing Capacity Network Import Interconnection Service pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff.

III.13.1.3.5.5.A. Offer Information.

(a) A New Import Capacity Resource that is not subject to the pivotal supplier test in Section III.A.23 is subject to the same offer information submission requirements for a New Generating Capacity Resource that are described in Section III.13.1.1.2.2.3.

(b) A New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and seeks to specify a price below which it would not accept a Capacity Supply Obligation for that resource, or a portion thereof, that is at or above the Dynamic De-List Bid Threshold must submit the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and documentation and information supporting such lowest price, which should include the documentation and information listed in Section III.13.1.1.2.2.3(a) and the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. The offer information may be submitted in the form of a curve (up to five price-quantity pairs) associated with a specific New Import Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.4 and must include the additional documentation described in that Section.

III.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources.

In addition to the review described in Section III.A.21, the Internal Market Monitor shall review each offer from New Import Capacity Resources. An offer from a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Section III.A.19 of Market Rule 1.

III.13.1.3.5.7. Qualification Determination Notification for New Import Capacity Resources.

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5.

No later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.1.2.8, a Lead Market Participant with a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and that submitted a request to submit offers in the Forward Capacity Auction pursuant to Section III.13.1.3.5.5.A(b) may: (a) lower the requested offer price of any price-quantity pair submitted to the ISO, provided that the revised price is greater than or equal to the Dynamic De-List Bid Threshold, or (b) withdraw any price-quantity pair of a requested offer price.

III.13.1.3.5.8. Rationing Election.

New Import Capacity Resources are subject to rationing except New Import Capacity Resource associated with an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request, which are eligible for the rationing election described in Section III.13.1.1.2.2.3(b).

III.13.1.4. Demand Capacity Resources.

To participate in a Forward Capacity Auction as a Demand Capacity Resource, a resource must meet the requirements of this Section III.13.1.4. Each Demand Capacity Resource shall be a minimum of 100 kW. An Active Demand Capacity Resource comprises one or more Demand Response Resources located in a single Dispatch Zone. An On-Peak Demand Resource or Seasonal Peak Demand Resource comprises one or more Assets located in a single Load Zone. An On-Peak Demand Resource or Seasonal Peak Demand Resource may consist of Load Management measures, Distributed Generation measures, or a combination thereof, or may consist solely of Energy Efficiency measures. A Demand Capacity Resource may include an end-use customer facility with a Net Supply Capability of 5 MW or more only if the facility's Net Supply Capability does not exceed its Maximum Facility Load. Demand Capacity Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Capacity Resource. Demand Capacity Resources are not permitted to submit import or export bids or Administrative Export De-List Bids.

III.13.1.4.1. Definition of New Demand Capacity Resource.

A New Demand Capacity Resource is an Active Demand Capacity Resource that has not cleared in a previous Forward Capacity Auction, and On-Peak Demand Resource consisting of measures that have not been in service prior to the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction, or a Seasonal Peak Demand Resource consisting of measures that have not been in service prior to the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. A Demand Capacity Resource that has previously been defined as an Existing Demand Capacity Resource shall be considered a New Demand Capacity Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.1. Qualification Process for New Demand Capacity Resources.

For Forward Capacity Auctions a New Demand Capacity Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's estimated demand reduction value as submitted and reviewed pursuant to this Section III.13.1.4. The FCA Qualified Capacity for a New Demand Capacity Resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

(a) For a resource to qualify as a New Demand Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit estimated demand reduction values and supporting information in the New Demand Capacity Resource Show of Interest Form as described in Section III.13.1.4.1.1.1. Second, the Project Sponsor must submit a New Demand Capacity Resource Qualification Package as described in Section III.13.1.4.1.1.2.

(b) For a resource to qualify as a New Demand Capacity Resource that is an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Project Sponsor must in addition submit, as part of the New Demand Capacity Resource Qualification Package, a Measurement and Verification Plan providing the documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.1, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.1.1. New Demand Capacity Resource Show of Interest Form.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource, the Project Sponsor must submit to the ISO a New Demand Capacity Resource Show of Interest Form as described in this Section III.13.1.4.1.1.1 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. A New Demand Capacity Resource Show of Interest Form for a resource composed of Energy Efficiency measures must represent a resource with a new and unique resource identification number. The ISO may waive the submission of any information not required for evaluation of a project.

A completed New Demand Capacity Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Capacity Resource will be located; the Dispatch Zone within which an Active Demand Capacity Resource will be located; estimated summer and winter demand reduction values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses); estimated total summer and winter demand reduction value of the Demand Capacity Resource (for an Active Demand Capacity Resource, this estimate must be consistent with the baseline calculation methodology in Section III.8.2); supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated demand reduction values; Demand Capacity Resource type (Active Demand Capacity Resource, On-Peak Demand Resource, or Seasonal Peak Demand Resource); brief Demand Capacity Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; the date by which the Project Sponsor expects to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the Project Sponsor's New Demand Capacity Resource Qualification Package has achieved its full demand reduction value; ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; for individual Distributed Generation projects and Demand Capacity Resource projects from a single facility with a demand reduction value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.1.1.2. New Demand Capacity Resource Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource, the Project Sponsor must submit a New Demand Capacity Resource

Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Capacity Resource Qualification Package shall conform to the requirements of this Section III.13.1.4.1.1.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.1.1.2.1. Source of Funding.

The Project Sponsor must provide in the New Demand Capacity Resource Qualification Package the source of funding, which includes, but is not limited to, the following: the source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; and a completed ISO credit application.

III.13.1.4.1.1.2.2. Measurement and Verification Plan.

For On-Peak Demand Resources and Seasonal Peak Demand Resources, the Project Sponsor must provide in the New Demand Capacity Resource Qualification Package a Measurement and Verification Plan that complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.1.2.3. Customer Acquisition Plan.

(a) A Project Sponsor with more than a single customer must include in the New Demand Capacity Resource Qualification Package a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

(b) A Project Sponsor for a New Demand Capacity Resource that includes one or more end-use customer facilities with behind-the-meter generation must include in the New Demand Capacity Resource Qualification Package information demonstrating that each facility's Net Supply Capability will be less than 5 MW or less than or equal to the facility's Maximum Facility Load.

III.13.1.4.1.1.2.4. Critical Path Schedule for a Demand Capacity Resource with a Demand Reduction Value of at Least 5 MW at a Single Retail Delivery Point.

The Project Sponsor of a Demand Capacity Resource with a demand reduction value of at least 5 MW at a single Retail Delivery Point shall provide in the New Demand Capacity Resource Qualification Package a critical path schedule as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.1.1.2.5. Critical Path Schedule for a Demand Capacity Resource with All Retail Delivery Points Having a Demand Reduction Value of Less Than 5 MW.

The Project Sponsor of a Demand Capacity Resource with all Retail Delivery Points having a demand reduction value of less than 5 MW shall provide in the New Demand Capacity Resource Qualification Package a critical path schedule comprised of a delivery schedule of the share of total offered demand reduction value achieved as of target dates, as follows: (i) the cumulative percentage of total demand reduction value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Project Sponsor's capacity award was made; (ii) the cumulative percentage of total demand reduction value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Project Sponsor's capacity award was made; and (iii) target date 3 which is the date by which the Project Sponsor expects to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the Project Sponsor's New Demand Capacity Resource Qualification Package has achieved its full demand reduction value, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total demand reduction value must be complete.

III.13.1.4.1.1.2.6. [Reserved.]

III.13.1.4.1.1.2.7. Capacity Commitment Period Election.

Project Sponsors shall be required to specify whether they are making the election set forth in this Section III.13.1.4.1.1.2.7 for each Forward Capacity Auction up to and including the auction held in February 2021 for the June 1, 2024 through May 31, 2025 Capacity Commitment Period, and no election shall be permitted thereafter.

For each Forward Capacity Auction occurring up to and including the February 2021 auction, in the New Demand Capacity Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Capacity Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Demand Capacity Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Capacity Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Capacity Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Capacity Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Capacity Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.1.1.2.7.

III.13.1.4.1.1.2.8. Offer Information from New Demand Capacity Resources.

(a) For a New Demand Capacity Resource that does not satisfy any of the conditions described in Sections III.A.21.1.1 or III.A.21.1.2 based on the information submitted at the time of the New Demand Capacity Resource Qualification Package, and for which the Project Sponsor does not provide a Load-Side Relationship Certification described in Section III.A.21.1.3, the Project Sponsor must include in the New Demand Capacity Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and sufficient documentation and information for a buyer-sider market power review pursuant to Section III.A.21.2. Such documentation and information includes all financial estimates, projected revenues, and cost projections for the project, including the project's pro-forma financing support data and anticipated out-of-market revenues (as defined in Section III.A.21.3(b)(i)). For a New Demand Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation.

A Project Sponsor that submits a Load-Side Relationship Certification as part of the New Demand Capacity Resource Qualification Package pursuant to Section III.13.1.4.1.1.2.9 must be prepared to provide both (1) the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and (2) the documentation and information described in this subsection (a), in the event that the

ISO determines that the Load-Side Relationship Certification does not meet the requirements of Section III.A.21.1.3.

(b) The Project Sponsor for a New Demand Capacity Resource must indicate in the New Demand Capacity Resource Qualification Package if an offer from the New Demand Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.1.1.2.9. Load-Side Interests.

If the Project Sponsor seeks to demonstrate one of the qualifying circumstances described in Section III.A.21.1.3 with regard to its New Demand Capacity Resource, the Project Sponsor must provide the Load-Side Relationship Certification in the New Demand Capacity Resource Qualification Package.

III.13.1.4.1.1.3. Initial Analysis for Active Demand Capacity Resources.

For each New Demand Capacity Resource that is an Active Demand Capacity Resource, the ISO shall perform an analysis based on the information provided in the New Demand Capacity Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Capacity Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Capacity Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.1.4. Consistency of the New Demand Capacity Resource Qualification Package and New Demand Capacity Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Capacity Resource Qualification Package for consistency with its New Demand Capacity Resource Show of Interest Form. The New Demand Capacity Resource Qualification Package may not contain material changes relative to the New Demand Capacity Resource Show of Interest Form. A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Capacity Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Active Demand Capacity Resource is located; (iv) a change in the total summer or winter demand reduction value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); or (vi) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.1.1.5. Evaluation of New Demand Capacity Resource Qualification Materials. The ISO shall review the information submitted by New Demand Capacity Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

(a) whether the information submitted by New Demand Capacity Resources is accurate and contains all of the elements required by this Section III.13.1.4;

(b) whether the critical path schedule submitted by New Demand Capacity Resources includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule submitted by New Demand Capacity Resources are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Capacity Resource are satisfied; and

(e) whether, in the case of a New Demand Capacity Resource that is an On-Peak Demand Resource or Seasonal Peak Demand Resource, the Measurement and Verification Plan complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.1.6. Qualification Determination Notification for New Demand Capacity Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Capacity Resource indicating whether the New Demand Capacity Resource has been accepted for participation in the Forward Capacity Auction.

(a) For a New Demand Capacity Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Capacity Resource type and the Demand Capacity Resource's summer and winter Qualified Capacity, which shall be the ISO-determined summer and winter demand reduction value increased by average avoided peak transmission and distribution losses (that is, eight percent).

(b) For a New Demand Capacity Resource accepted for participation in the Forward Capacity Auction, the notification will provide the ISO's determination as to whether the New Demand Capacity Resource satisfies any of the conditions described in Section III.A.21.1 and the basis for such determination.

(c) For a New Demand Capacity Resource accepted for participation in the Forward Capacity Auction and subject to buyer-side market power review pursuant to Section III.A.21.2, the notification will provide the Internal Market Monitor's determinations regarding whether the New Demand Capacity Resource's requested lowest offer price, submitted pursuant to Section III.13.1.4.1.1.2.8(a), must be mitigated, as described in Section III.A.21.2.3. The ISO shall not disclose to the Project Sponsor any information regarding the potential impact of any offer from the Project Sponsor on Capacity Clearing Prices.

(d) For a New Demand Capacity Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.2. Definition of Existing Demand Capacity Resources.

Demand Capacity Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Capacity Resources, shall be Existing Demand Capacity Resources. Existing Demand Capacity Resources shall include and are limited to Demand Capacity Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in this Section III.13.1.4, Existing Demand Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Capacity Resources shall be subject to Section III.13.1.2.2.5.2. An On-Peak Demand Resource or Seasonal Peak Demand Resource may not include in its summer or winter demand reduction value an Energy Efficiency measure whose Measure Life will expire before the beginning of the applicable season of the associated Capacity Commitment Period.

III.13.1.4.2.A Qualified Capacity for Existing Demand Capacity Resources.

(a) For Existing Demand Capacity Resources composed of Energy Efficiency measures, the summer (or winter, as applicable) Qualified Capacity shall equal the lesser of: (i) the sum of the summer (or winter, as applicable) demand reduction values of the installed Energy Efficiency measures as of the Existing Capacity Qualification Deadline (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to start of the applicable season of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses) and any summer (or winter, as applicable) capacity that has cleared in a Forward Capacity Auction and has not yet achieved FCM Commercial Operation (provided that such capacity is being monitored by the ISO pursuant to the provisions of Section III.13.3, is expected to achieve all its critical path schedule milestones prior to the start of the applicable season of the relevant Capacity Commitment Period, and for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy) and (ii) the amount of summer (or winter, as applicable) capacity that cleared in a Forward Capacity Auction as a New Demand Capacity Resource.

(b) For Existing Demand Capacity Resources other than those composed of Energy Efficiency measures, the summer and winter Qualified Capacity shall equal the summer and winter demand reduction value, respectively, increased by average avoided peak transmission and distribution losses.

III.13.1.4.2.1. Qualified Capacity Notification for Existing Demand Capacity Resources.

(a) For each Existing Demand Capacity Resource, the ISO will notify the Resource's Lead Market Participant no later than 15 Business Days before the Existing Capacity Retirement Deadline of: the

Demand Capacity Resource type; summer and winter Qualified Capacity; the Load Zone in which the Demand Capacity Resource is located; and, for Active Demand Capacity Resources, the Dispatch Zone in which the resource is located.

(b) If the Lead Market Participant believes that the ISO's assessment of the Qualified Capacity is inaccurate, the Market Participant must notify the ISO within five Business Days of receipt of the Qualified Capacity notification.

(c) If a Market Participant with an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource wishes to change its Demand Capacity Resource type, the Market Participant must submit an Updated Measurement and Verification Plan to reflect the change in its resource type. Updated Measurement and Verification Plans must be received by the ISO no later than five Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Capacity Resource type may not be changed during the Capacity Commitment Period.

(d) A Market Participant with an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource may provide an Updated Measurement and Verification Plan as described in Section III.13.1.4.3.1.2 that complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals. Updated Measurement and Verification Plans must be received by the ISO no later than five Business Days after receipt of the Qualified Capacity notification.

(e) If an Existing Demand Capacity Resource is not submitting a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO's notification.

III.13.1.4.2.2. Existing Demand Capacity Resource De-List Bids.

An Existing Demand Capacity Resource may submit a Permanent De-List Bid or Retirement De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.5 no later than the Existing Capacity Retirement Deadline or a Static De-List Bid pursuant to the provisions of Section III.13.1.2.3.1.1 no later than the Existing Capacity Qualification Deadline, provided, however, that no de-list bid shall be used as a mechanism to inappropriately qualify Assets associated with Existing Demand Capacity Resources as New Demand Capacity Resources.

III.13.1.4.3. Measurement and Verification Applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

To demonstrate the demand reduction value of an On-Peak Demand Resource or Seasonal Peak Demand Resource, the Project Sponsor or Market Participant of such a resource participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals, or reconfiguration auctions shall submit to the ISO the Measurement and Verification Documents in accordance with this Section III.13.1.4.3 and the ISO New England Manuals. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents.

Measurement and Verification Documents must demonstrate both availability and performance of an On-Peak Demand Resource or Seasonal Peak Demand Resource in reducing demand coincident with Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours such that the reported monthly demand reduction value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manuals and ISO New England Operating Procedures. The Measurement and Verification Documents shall serve as the basis for the claimed demand reduction value of an On-Peak Demand Resource or Seasonal Peak Demand Resource. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved demand reduction value of the On-Peak Demand Resource or Seasonal Peak Demand Resource. The Measurement and Verification Documents shall contain a projection of the On-Peak Demand Resource's or Seasonal Peak Demand Resource's demand reduction value for each month of the Capacity Commitment Period and over the expected Measure Lives associated with the Demand Capacity Resources. An On-Peak Demand Resource's or Seasonal Peak Demand Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours. If an On-Peak Demand Resource or Seasonal Peak Demand Resource includes Distributed Generation, the Measurement and Verification Documents must describe the individual metering or metering protocol used to monitor and verify the output of the Distributed Generation, consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals.

The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Project Sponsor's total demand reduction value from eligible pre-existing measures and new measures, and the Project Sponsor's total demand reduction value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Project Sponsors. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Project Sponsor, the Measurement and Verification Documents for an On-Peak Demand Resource or a Seasonal Peak Demand Resource may also include one or more Measurement and Verification Reference Report(s) submitted during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports shall update the prospective demand reduction value of the On-Peak Demand Resource or Seasonal Peak Demand Resource based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Project Sponsor, an Updated Measurement and Verification Plan for an On-Peak Demand Resource or a Seasonal Peak Demand Resource may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the

Demand Capacity Resource project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total claimed demand reduction value or the Demand Capacity Resource type from the applicable Forward Capacity Auction in which the Project Sponsor's offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Capacity Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Project Sponsors for On-Peak Demand Resources and Seasonal Peak Demand Resources shall submit no less frequently than once per year, a statement certifying that the Demand Capacity Resource projects for which the Project Sponsor is requesting compensation continue to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For On-Peak Demand Resources and Seasonal Peak Demand Resources targeting customer facilities with greater than or equal to 10 kW of demand reduction value per facility, Project Sponsors shall maintain records of retail customers served including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly demand reduction values. For On-Peak Demand Resources and Seasonal Peak Demand Resources targeting customer facilities with under 10 kW of demand reduction value per facility, the Project Sponsor shall maintain records as described above for customer facilities with greater than or equal to 10 kW of demand reduction value per facility, or shall maintain records of aggregated demand reduction value and measures installed by Load Zone and meter domain. Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Capacity Resource is permanently de-listed from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. ISO Review of Measurement and Verification Documents.

The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor or Lead Market Participant to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.4.1.1.6. Offers composed of separate resources may not be modified or withdrawn after the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Capacity Resource, April through November where the summer resource is a Demand Capacity Resource) of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period (October through May where the summer resource is not a Demand Capacity Resource, December through March where the summer resource is a Demand Capacity Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Capacity Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource. If the winter capacity of the offer composed of separate resources in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

(d) Offers composed of separate resources are subject to the locational restrictions specified in the following table:

		Location of Summer Resource			
		Import-Constrained Capacity Zone	Rest-of-Pool Capacity Zone	Export-Constrained Capacity Zone	Nested Export-Constrained Capacity Zone
Location of Winter Resource	Import-Constrained Capacity Zone	Eligible (within same Capacity Zone)	Eligible	Eligible	Eligible
	Rest-of-Pool Capacity Zone	Ineligible	Eligible	Eligible	Eligible
	Export-Constrained Capacity Zone	Ineligible	Ineligible	Eligible (within same Capacity Zone)	Eligible (within same Capacity Zone where nested export-constrained

					Capacity Zone is located)
	Nested Export-Constrained Capacity Zone	Ineligible	Ineligible	Ineligible	Eligible (within same Capacity Zone)

(e) A Renewable Technology Resource may only participate in an offer composed of separate resources if its FCA Qualified Capacity has not been prorated pursuant to Section III.13.1.1.2.10.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than five Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Capacity Resource of the resource's final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource's financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. Self-Supplied FCA Resources.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the FCM Deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c) and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity's Capacity Load Obligation in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Capacity Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. Self-Supplied FCA Resource Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource or Existing Import Capacity Resource, and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource's summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating

Capacity Resource, a New Import Capacity Resource or a New Demand Capacity Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list, retire or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.

(a) Resource name, quantity and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid and Retirement De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(b) The quantity and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(e) No later than three Business Days after the Existing Capacity Retirement Deadline, the ISO shall post on its website information concerning Permanent De-List Bids and Retirement De-List Bids.

(f) The name of each Lead Market Participant submitting Static De-List Bids, Export Bids, and Administrative Export De-List Bids, as well as the number and type of such de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4(b), and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids, Permanent De-List Bids, and Retirement De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

(g) No later than five Business Days after the close of the New Capacity Show of Interest Submission Window, the ISO shall post on its website the aggregate quantity of supply offers and demand bids that have been elected to participate in the substitution auction by Capacity Zone (where the zones used are those being studied for inclusion in the associated Forward Capacity Auction pursuant to Section III.12.4).

III.13.1.9. Financial Assurance.

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Capacity Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Resources) and New Demand Capacity Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the FCM Deposit by the Project Sponsor for a New Generating Capacity Resource or New Demand Capacity Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Capacity Resource in the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the FCM Deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Capacity Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Capacity Resource clears in the Forward Capacity Auction, financial assurance required prior to the auction pursuant to FAP shall be applied toward the resource's financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Capacity Resource clears in the Forward Capacity Auction, the financial assurance required prior to the auction pursuant to FAP will be released pursuant to the terms of the ISO New England Financial Assurance Policy.

III.13.1.9.2. Financial Assurance for New Generating Capacity Resources and New Demand Capacity Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource's offer or a New Demand Capacity Resource's offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. Failure to Provide Financial Assurance or to Meet Milestone.

If a New Generating Capacity Resource or New Demand Capacity Resource: (i) fails to provide the required financial assurance as described in the ISO New England Financial Assurance Policy or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4A, it shall lose its Capacity Supply Obligation and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. Release of Financial Assurance.

Once a New Generating Capacity Resource or New Demand Capacity Resource achieves FCM Commercial Operation, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand Capacity Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. Forfeit of Financial Assurance.

Where any financial assurance is forfeited pursuant to the provisions of Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to Section III.13 shall be used to reduce charges incurred by load in the relevant Capacity Zone.

III.13.1.9.2.4. Financial Assurance for New Import Capacity Resources.

A New Import Capacity Resource that is backed by a new External Resource or will be delivered over an Elective Transmission Upgrade with a Capacity Network Import Interconnection Service Interconnection Request pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource or the Elective Transmission Upgrade achieves FCM Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.

III.13.1.9.3. Qualification Process Cost Reimbursement Deposit.

For each New Capacity Show of Interest Form and New Demand Capacity Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below ("Qualification Process Cost Reimbursement Deposit"). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project's critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22, 23 or 25 of Section II of the Transmission, Markets and Services Tariff or where a resource modification does not require a revision to the Interconnection Agreement.

New Generating Capacity Resources ≥ 20 MW or an Import Capacity Resource associated with an Elective Transmission Upgrade that has not achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff	**New Generating Capacity Resources < 20 MW and ≥ 2 MW**	**Imports and New Demand Capacity Resources**		**New Generating Capacity Resources < 2 MW**
Including Up-rates, Re-powering, Environmental Compliance &	*Including Up-rates, Re-powering, Environmental Compliance &*			

Intermittent Power Resources	*Intermittent Power Resources*			
$25,000	$7,500	$1,000		$500
With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement	*With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement*			
$15,000	$6,500	n/a		n/a

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for FCM Commercial Operation, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s) associated with the qualification process and critical path schedule monitoring, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Capacity Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Capacity Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO's consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

(a) each Capacity Commitment Period shall begin in June;

(b) the Existing Capacity Retirement Deadline will be in March, approximately four years and three months before the beginning of the Capacity Commitment Period;

(c) the New Capacity Show of Interest Submission Window will be in April, approximately four years and two months before the beginning of the Capacity Commitment Period;

(d) the Existing Capacity Qualification Deadline will be 90 days after the Existing Capacity Retirement Deadline, approximately four years before the beginning of the Capacity Commitment Period;

(e) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and

(f) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

III.13.1.11 Opt-Out for Resources Electing Multiple-Year Treatment.

Beginning in the qualification process for the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2018), any resource that had elected in a Forward Capacity Auction prior to the ninth Forward Capacity Auction (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer cleared may, by submitting a written notification to the ISO no later than the Existing Capacity Qualification Deadline (or, in the case of the ninth Forward Capacity Auction, no later than September 19, 2014), opt-out of the remaining years of the resource’s multiple-year election. A decision to so opt-out shall be irrevocable. A resource choosing to so opt-out will participate in subsequent Forward Capacity Auctions in the same manner as other Existing Capacity Resources.

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

(i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);

(ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at $7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

(iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

(1) at prices above \$7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;

(2) at prices below \$7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between \$7.03/kW-month and \$0.00/kW-month and determined by the following quantities:

(a) At the price of \$0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.

(b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at \$7.03/kW-month, the quantity shall be the lesser of:

1. 35,437 MW; and
2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month;

(c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at \$7.03/kW-month, the quantity shall be the lesser of:

1. 35,090 MW; and
2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month;

(d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at \$7.03/kW-month, the quantity shall be the lesser of:

1. 34,865 MW; and
2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month

(3) a price of \$7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of \$0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative \$0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall include a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. The descending clock auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability, New Import Capacity

Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Rationing Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \le p_1, \\ q_2, & \text{if } p_3 < p \le p_2, \\ \cdots & \cdots \quad , \\ q_m, & \text{if } p \le p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3. If the Internal Market Monitor has determined that a New Capacity Resource must use a New Resource Offer Floor Price pursuant to Section III.A.21.2.3 such New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. .

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as established or modified pursuant to Section III.A.21.4) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as established or modified pursuant to Section III.A.21.4), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as established or modified pursuant to Section III.A.21.4) that are less than the Dynamic De-List Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment

Period at that round's prices. Such an offer shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or where a Permanent De-List Bid or Retirement De-List Bid is subject to an election under Section III.13.1.2.4.1(a), the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.1.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be included in the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, the price specified in the Commission-approved de-list bid is less than the Forward Capacity Auction Starting Price, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Capacity Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3. If the Internal Market Monitor has determined that a new Self-Supplied FCA Resource must use a New Resource Offer Floor Price pursuant to Section III.A.21.2.3, the new resource's self-supplied quantity shall be entered into each round of the Forward Capacity Auction at prices at or above the New Resource Offer Floor Price.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Rationing Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

The aggregate supply curve for the New England Control Area, the Total System Capacity, shall reflect at each price the sum of the following:

(1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:

(i) the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits)), or;

(ii) the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price, and;

(4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:

(i) that interface's approved capacity transfer limit (net of tie benefits), or;

(ii) the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price), or;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**.

If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price.

(c) **Export-Constrained Capacity Zones**.

For a Capacity Zone modeled as an export-constrained Capacity Zone, if all of the following conditions are met during the round:

(1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero;
(2) in the case of a nested Capacity Zone, the Forward Capacity Auction is concluded for the Capacity Zone within which the nested Capacity Zone is located, and;
(3) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and
(ii) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone.

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

The Capacity Clearing Price for a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located,

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If all of the conditions above are not satisfied in the round, then the auctioneer shall publish the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero) and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.

III.13.2.4.1 Calculation of Forward Capacity Auction Starting Price, CONE, and Net CONE.

The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is $12.400/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is $7.468/kW-month.

CONE and Net CONE shall be recalculated no less often than once every three years. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

III.13.2.4.2 Interim Year Adjustments to CONE and Net CONE.

(a) For years in which no full recalculation is performed pursuant to Section III.13.2.4.1, CONE and Net CONE will be adjusted for each Forward Capacity Auction with the following updates to the capital budgeting model used to calculate the CONE and Net CONE values set forth above in this Section III.13.2.4.

(1) Each line item associated with capital costs that is included in the capital budgeting model will be updated to reflect changes in the Bureau of Labor Statistics Producer Price Index for Machinery and Equipment: General Purpose Machinery and Equipment (WPU114).

(2) For each line item in (1) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the CONE and Net CONE values set forth in Section III.13.2.4.1. The value of each line item associated with capital costs in the capital budgeting model will be adjusted by the relevant multiplier.

(3) The energy and ancillary services offset values in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub Day-Ahead Peak electricity prices, as published by ICE for the first five trading days in February, for each month of the Capacity Commitment Period to which the updated value will apply.

(4) The CONE and Net CONE values adjusted pursuant to this Section III.13.2.4.2 will be published on the ISO's web site.

(5) If any of the values required for the calculations described in this Section III.13.2.4.2 are unavailable, then comparable values, prices or sources shall be used.

(b) Prior to applying the annual adjustment described in this Section III.13.2.4.2 for the Capacity Commitment Period beginning on June 1, 2026, CONE will be increased by $1.391/kW-month and Net CONE will be increased by $1.197/kW-month to reflect the elimination of the Offer Review Trigger Price mechanism applicable to New Capacity Resources in the Forward Capacity Market.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Capacity Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply

Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the capacity has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the primary auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated after the substitution auction is completed if one of the following conditions is met: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process and retains some portion of its Capacity Supply Obligation in the substitution auction; or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process, the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price, and the Proxy De-List Bid retains some portion of its Capacity Supply Obligation in the substitution auction. The second run of the primary auction-clearing process: (i) excludes all Proxy De-List Bids, (ii) includes the offers and bids of resources compiled pursuant to Section III.13.2.3.2 that did not receive a Capacity Supply Obligation in the first run of the primary auction-clearing process, excluding the offers, or portion thereof, associated with resources that acquired a Capacity Supply Obligation in the substitution auction, and (iii) includes the capacity of resources, or portion thereof, that retain a Capacity Supply Obligation after the first run of the primary auction-clearing process and the substitution auction. The second run of the primary auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the primary auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receive a Capacity Supply Obligation as a result of the first run of the primary auction-clearing process shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period. Where the second run of the primary auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the primary auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Rationing Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price.

III.13.2.5.2.5. Reliability Review.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, and substitution auction demand bid to determine whether the capacity associated with that bid is needed for reliability reasons during the

Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review of de-list bids will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station. The reliability review of substitution auction demand bids that would otherwise clear will be conducted in order beginning with the resource whose cleared bids contribute the greatest amount to social surplus. The capacity associated with a bid shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. Bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) If a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction. If the ISO has determined that some or all of the capacity associated with a substitution auction demand bid that would otherwise clear is needed for reliability reasons, then the entire demand bid will not be further included in the substitution auction.

(c) The Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject a de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability (provided that resources that have Permanent De-List Bids or Retirement De-List Bids rejected for reliability shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii))).

(g) If a Permanent De-List Bid or a Retirement De-List Bid is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1.

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5A Fuel Security Reliability Review

(a) This Section III.13.2.5.2.5A will remain in effect for the 2022/23, 2023/24 and 2024/25 Capacity Commitment Period, after which this Section III.13.2.5.2.5A will sunset.

(b) This Section III.13.2.5.2.5A will apply to (i) Retirement De-List Bids, (ii) substitution auction demand bids, and (iii) bilateral transactions and reconfiguration auctions demand bids submitted by an Existing Generating Capacity Resource that has been identified as being needed for fuel security during a Forward Capacity Auction. Terms set out in this Section III.13.2.5.2.5A will apply only for the period and resources described within this Section III.13.2.5.2.5A. Where the terms and conditions in this Section III.13.2.5.2.5A differ from terms otherwise set out in Section III.13, the terms of this Section III.13.2.5.2.5A will control for the period and circumstances described in Section III.13.2.5.2.5A.

(c) A fuel security reliability review for the Forward Capacity Market will be performed pursuant to Appendix L to Section III of the Tariff, and in accordance with the inputs and methodology set out to establish the fuel security reliability standard in Appendix I of Planning Procedure No. 10.

(d) For fuel security reliability reviews performed for the primary Forward Capacity Auction, the fuel security reliability review will be performed after the Existing Capacity Retirement Deadline and conducted in descending price order using the price as submitted in the Retirement De-List Bids. Bids with the same price will be reviewed in the order that produces the least negative impact to reliability. Where multiple bids have the same price and the retirement of the Existing Generating Capacity Resources would have the same impact to reliability, they will be reviewed based on their submission time. If bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d), and (2) the minimum aggregate quantity required for reliability from the generating station. An Existing Generating Capacity Resource may be needed for both fuel security and for transmission security pursuant to Section III.13.2.5.2.5. The fuel security reliability review will be performed in advance of the reliability review for transmission security. Where an Existing Generating Capacity Resource is needed for both fuel security reasons pursuant to this Section III.13.2.5.2.5A, and transmission security reliability reasons pursuant to Section III.13.2.5.2.5, the generator will be retained for fuel security for purposes of cost allocation.

(e) If an Existing Generating Capacity Resource is identified as being needed for fuel security reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable may not participate in Annual Reconfiguration Auctions for the Capacity Commitment Period(s) for which it is needed for fuel security, or earlier 2022/23, 2023/24 and 2024/25 Capacity Commitment Periods. Such an Existing Generating Capacity Resource that is identified as being needed for fuel security may participate in monthly bilateral transactions and monthly reconfiguration auctions, but may not submit monthly bilateral transactions for December, January or February, or demand bids for the December, January, or February monthly reconfiguration auctions for any period for which they have been identified as being needed for fuel security.

(f) Participants that have submitted a Retirement De-List Bid will be notified by ISO New England if their resource is needed for fuel security reliability reasons no later than 90 days after the Existing Capacity Retirement Deadline. Participants that have submitted a substitution auction demand bid, and where the demand bid has been rejected for reliability reasons, will be notified after the relevant Forward Capacity Auction has been completed.

(g) Where a Retirement De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for fuel security reliability reasons, the provisions of III.13.2.5.2.5(b) shall apply.

(h) Existing Generating Capacity Resources that have had their Retirement De-list Bid rejected for fuel security reliability reasons and that do not elect to unconditionally or conditionally retire shall be eligible for compensation pursuant to Section III.13.2.5.2.5.1, except that the difference between payments based on resource de-list bids or cost-of-service compensation as detailed in Section III.13.2.5.2.5.1 and payments based on the Capacity Clearing Price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated on a regional basis to Real Time Load Obligation, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (DARD Pumps and other electric storage based DARDs) and Real-Time Load Obligation associated with Coordinated External Transactions, allocated and collected over a 12 month period. Resources that that are identified as needed for fuel security reliability reasons will have their capacity entered into the Forward Capacity Auction pursuant to III.13.2.5.2.5(g) and III.13.2.3.2(b).

(i) Where an Existing Generating Capacity Resource elects a cost-of-service agreement pursuant to Section III.13.2.5.2.5.1 to address a fuel security reliability need, the term of such a cost-of-service agreement may not exceed two years, including renewal through evergreen provisions. A cost-of-service agreement entered into for the 2024/2025 Capacity Commitment Period shall be limited to a total duration of one year.

(j) The ISO shall perform an annual reevaluation of any Existing Generating Capacity Resources retained for reliability under this provision. If a resource associated with a Retirement De-List Bid that was rejected for reliability reasons pursuant to this section, is found to no longer be needed for fuel security, and is not needed for another reliability reason pursuant to Section III.13.2.5.2.5, the resource will be retired from the system as described in Section III.13.2.5.2.5.3(a)(1). In no case will a resource retained for fuel security be retained for fuel security beyond June 1, 2025.

(k) The ISO will review Retirement De-List Bids rejected for fuel security reliability reasons with the Reliability Committee in the same manner as described in Section III.13.2.5.2.5(h).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the "just and reasonable" standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

(e) If ISO-NE is a party to a cost-of-service agreement filed after January 1, 2019 that changes any resource performance-related obligations contained in Section III, Appendix I (provided that those obligations are different than the obligations of an Existing Generating Capacity Resource with a Capacity Supply Obligation), no later than 30 days after such agreement is filed with the Commission, ISO-NE shall provide to stakeholders quantitative and qualitative information on the need for, and the impacts of, the proposed changes.

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Capacity Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section

III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: (1) submitted a Retirement De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (2) submitted a Permanent De-List Bid or Retirement De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a), and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (3) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (4) had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: (1) submitted an Internal Market Monitor-approved Permanent De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliablity pursuant to Section III.13.1.2.3.1.5.1; (2) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (3) had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to its Rationing Minimum Limit pursuant to Sections III.13.1.1.2.2.3 and III.13.1.2.1.2. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Rationing Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Rationing Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.7. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for each import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone.

The Capacity Clearing Price in a nested Capacity Zone shall not be higher than the Capacity Clearing Price in the Capacity Zone within which it is located.

III.13.2.7.3. [Reserved.]

III.13.2.7.3A. Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3.A(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3.A(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.
Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that seek to maximize social surplus for the associated Capacity Commitment Period. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.
Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity,

then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) [Reserved.]

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource's location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources) shall be cleared.

III.13.2.8. Capacity Substitution Auctions.

The final substitution auction shall take place for the Forward Capacity Auction associated with the June 1, 2025 to May 31, 2026 Capacity Commitment Period, and no substitution auctions shall be conducted thereafter. Notwithstanding the foregoing, the provisions of Section III.12 of Market Rule 1 and Attachment K to the OATT addressing the manner in which Capacity Supply Obligations acquired or shed through the substitution auction are accounted for in the calculation of the Installed Capacity Requirement and related values and in carrying out the regional system planning process shall continue to have full force and effect.

III.13.2.8.1. Administration of Substitution Auctions.

Following the completion of the primary auction-clearing process of the Forward Capacity Auction as provided for in Section III.13.2, the ISO shall conduct a substitution auction, using a static double auction to clear supply offers (offers to assume a Capacity Supply Obligation) and demand bids (bids to shed a Capacity Supply Obligation). Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected.

III.13.2.8.1.1. Substitution Auction Clearing and Awards.

The substitution auction shall maximize total social surplus as specified by the demand bids and supply offers used in the auction. The maximization is constrained as follows:

(i) By the external interface limits modeled in the primary auction-clearing process.

(ii) Such that the net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero.

(iii) Such that, for each import-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is less than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than or equal to the zone threshold quantity specified below.

(iv) Such that, for each export-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is greater than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than or equal to the zone threshold quantity specified below.

In applying constraint (iii), the zone threshold quantity for an import-constrained Capacity Zone shall be equal to the sum of its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.2 and the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located outside the import-constrained Capacity Zone, that are used to export capacity across an external interface connected to the import-constrained Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraint (iv), the zone threshold quantity for an export-constrained Capacity Zone shall be equal to its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.3 less the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located in the export-constrained Capacity Zone, including any Export Bids and any Administrative Export De-List Bids in an associated nested export-constrained Capacity Zone, that are used to export capacity across an external interface connected to another Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations of Import Capacity Resources at each external interface connected to the Capacity Zone.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction shall include the Capacity Supply Obligations awarded to Proxy De-List Bids within the zone, and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations shed from demand bids associated with Proxy De-List Bids within the zone.

In cases in which there are multiple clearing outcomes that would each maximize the substitution auction's objective, the following tie-breaking rules will apply in the following sequence: (i) non-rationable demand bids associated with Lead Market Participants having the largest total FCA Qualified

Capacity of Existing Capacity Resources will be cleared first; and (ii) rationable supply offers will be cleared in proportion to their offer quantity.

For Intermittent Power Resources, other than those participating as the summer resource in a Composite FCM Transaction, the cleared award for supply offers and demand bids shall be adjusted for the months in the winter period (as described in Section III.13.1.5) using the ratio of the resource's cleared offer or bid amount divided by its FCA Qualified Capacity multiplied by its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2 after removing any portion of the resource's winter Qualified Capacity that is participating in a Composite FCM Transaction.

The cleared offer amount awarded to a Composite FCM Transaction in the substitution auction will be assigned to the summer and winter resources for their respective obligation months during the Capacity Commitment Period as described in Section III.13.1.5.

If, after the substitution auction, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.2.8.1.2. Substitution Auction Pricing.

The substitution auction will specify clearing prices for Capacity Zones and external interfaces as follows.

For each import-constrained Capacity Zone, if the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the import-constrained Capacity Zone shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

For each export-constrained Capacity Zone,

(i) if the sum of the zone's total Capacity Supply Obligations, including Capacity Supply Obligations in a nested Capacity Zone, awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction including net cleared Capacity Supply Obligations in the nested Capacity Zone is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the export-constrained Capacity Zone (excluding supply offers and demand bids in the nested Capacity Zone that are not treated as offers and bids in the export-constrained Capacity Zone pursuant to Section III.13.2.8.1.2(ii)) shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

(ii) if the sum of a nested Capacity Zone's Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the nested Capacity Zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the nested Capacity Zone shall be treated as offers and bids in the export-constrained Capacity Zone within which the nested Capacity Zone is located, for purposes of determining substitution auction clearing prices.

The substitution auction clearing prices for the Rest-of-Pool Capacity Zone and for any constrained zones pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the demand bid or supply offer that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing prices shall be set equal to the Capacity Clearing Prices.

The substitution auction clearing price for a constrained Capacity Zone that is not pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the demand bid or supply offer associated with the separately-priced constrained Capacity Zone that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price shall be set equal to the Capacity Clearing Price for the constrained Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone that is not pooled with the export-constrained Capacity Zone in which it is located for pricing purposes shall be determined by the price of the demand bid or supply offer that is marginal in the nested export-constrained Capacity Zone. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price for the nested export-constrained Capacity Zone shall be equal to the Capacity Clearing Price for that nested export-constrained Capacity Zone.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control

Area is less than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then supply offers and demand bids in the substitution auction at the interface shall be treated as offers and bids in the modeled Capacity Zone associated with that interface for purposes of determining substitution auction clearing prices.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the substitution auction clearing price for that interface will be determined by the demand bid or supply offer that is marginal at that interface. If a cleared demand bid associated with a Proxy De-List Bid is marginal at the external interface, then the substitution auction clearing price for that interface shall be set equal to the Capacity Clearing Price for that interface.

The substitution auction clearing price for an import-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary action-clearing process of the Forward Capacity Auction are greater than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not be lower than the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Capacity Zone within which it is located.

The substitution auction clearing price at an external interface shall not exceed the substitution auction clearing price in the Capacity Zone connected to the external interface.

If, pursuant to the rules specified above, the substitution auction clearing price for any Capacity Zone or external interface would exceed the Capacity Clearing Price for that location, the substitution auction clearing price for that location only is set equal to its Capacity Clearing Price.

The substitution auction clearing price for any Capacity Zone or external interface cannot be less than negative one multiplied by the Forward Capacity Auction Starting Price.

III.13.2.8.2. Supply Offers in the Substitution Auction.

III.13.2.8.2.1. Supply Offers.

To participate as supply in the substitution auction, a Project Sponsor for a New Capacity Resource must meet the following criteria:

(a) The Project Sponsor and the New Capacity Resource must meet all the requirements for participation in the Forward Capacity Auction specified in Section III.13.1.

(b) The Project Sponsor must elect to have the resource participate in the substitution auction during the New Capacity Show of Interest Window. Pursuant to an election, the resource's total amount of FCA Qualified Capacity that qualifies as a New Capacity Resource will be obligated to participate in the substitution auction, including any capacity of a Renewable Technology Resource that was not qualified due to proration pursuant to Section III.13.1.1.2.10(a), and subject to the other provisions of this Section III.13.2.8.2.

(c) The Project Sponsor must certify that the New Capacity Resource is a Sponsored Policy Resource as part of the submission of the New Capacity Qualification Package.

Substitution auction supply offers are rationable.

A resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) is not eligible to participate as supply in the substitution auction. A resource is not eligible to participate as supply in the substitution auction if it has submitted a demand bid for the substitution auction.

A Composite FCM Transaction comprised of a summer resource that is a Sponsored Policy Resource is eligible to participate as supply in the substitution auction.

A Conditional Qualified New Resource may participate in the substitution auction provided that the resource with which it has overlapping interconnection impacts: (i) did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process, and: (ii) is not eligible to participate in the substitution auction. A resource having a higher priority in the queue than a Conditional Qualified New Resource with which it has overlapping interconnection impact may participate in the substitution auction provided that the Conditional Qualified New Resource did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process.

III.13.2.8.2.2. Supply Offer Prices.

Project Sponsors must submit substitution auction supply offer prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction supply offer must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price increases. A supply offer price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the offer quantity does not equal the resource's FCA Qualified Capacity, the quantity for which no offer price was submitted will be assigned a price equal to the Forward Capacity Auction Starting Price.

III.13.2.8.2.3. Supply Offers Entered into the Substitution Auction

Supply offers for resources that satisfy all of the criteria in Section III.13.2.8.2.1 to participate in the substitution auction may be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) Any portion of a resource's FCA Qualified Capacity that was cleared (received a Capacity Supply Obligation) in the primary auction-clearing process will be removed from the resource's substitution auction supply offer beginning with the lowest priced price-quantity pairs.

(b) After performing the adjustment specified in Section III.13.2.8.2.3(a), any price-quantity pairs in a resource's substitution auction supply offer with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface are removed from the offer.

III.13.2.8.3. Demand Bids in the Substitution Auction.

III.13.2.8.3.1. Demand Bids.

Market Participants with Existing Generating Capacity Resources or Existing Import Capacity Resources associated with External Elective Transmission Upgrades may elect to submit demand bids for the substitution auction for those resources by the Existing Capacity Retirement Deadline. The election must specify the total amount of the resource's Qualified Capacity that will be associated with its demand bid.

A resource, including any portion of an existing resource that qualifies as a New Capacity Resource, must have achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b) in order to participate as demand in the substitution auction.

Regardless of whether an election is made, a demand bid is required for any portion of a resource that is associated with a Retirement De-List Bid, provided that the entire resource has achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b).

A resource for which a demand bid election has been made cannot participate in a Composite FCM Transaction, cannot be designated as a Self-Supplied FCA Resource, and will not have incremental summer or winter capacity that does not span the entire Capacity Commitment Period subjected to the treatment specified in Section III.13.1.1.1.3.A.

Demand bids are non-rationable.

A demand bid will be entered into the substitution auction for the portion of the resource that receives a Capacity Supply Obligation in the primary auction-clearing process, subject to the other provisions of this Section III.13.2.8.3. A resource, or portion thereof, associated with a cleared demand bid shall be retired from all New England Markets at the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.2.8.3.1A Substitution Auction Test Prices.

(a) **Participant-Submitted Test Price.** For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants that submit a substitution auction demand bid must submit a test price, calculated using the method described below, by the Existing Capacity Retirement Deadline.

The test price for the capacity associated with a resource's demand bid must be calculated using the same methodology as a Retirement De-List Bid, except that a Market Participant may not submit test prices for multiple price-quantity segments but must submit a single test price using, as necessary, aggregated cost and revenue data. The test price must be accompanied by the same documentation required for Retirement De-List Bids above the Dynamic De-List Bid Threshold pursuant to Section III.13.1.2.3.2.1. A Market Participant must submit a test price regardless of whether the price is below the Dynamic De-List Bid Threshold.

A Market Participant is not required to submit a test price for any resource for which the demand bid is less than 3 MW. The applicable test price for any such resource is $0.00/kW-month.

(b) **IMM-Determined Test Price.** The Internal Market Monitor shall review each test price submission using the methodology specified in Section III.13.1.2.3.2.1 for evaluating Retirement De-List Bids, regardless of whether the submitted test price is below the Dynamic De-List Bid Threshold. For purposes of this review, the expected revenues for a cleared substitution auction demand bid shall not be included as a component of opportunity costs. After due consideration and consultation with the Market Participant, as appropriate, the Internal Market Monitor shall replace the submitted test price with an IMM-determined test price if the submitted test price is not consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The Internal Market Monitor's determination regarding a Market Participant-submitted test price shall be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

The test price used for purposes of the substitution auction shall be the Market Participant-submitted test price, as adjusted by the Internal Market Monitor pursuant to this Section III.13.2.8.3.1A(b), and as further adjusted by the Commission in response to the Internal Market Monitor's filing pursuant to Section III.13.1.2.4(a).

III.13.2.8.3.2. Demand Bid Prices.

Market Participants must submit substitution auction demand bid prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction demand bid must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price decreases. A demand bid price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the bid quantity does not equal the total bid amount submitted by the Market Participant or required for a Retirement De-List Bid pursuant to Section III.13.2.8.3.1, the quantity for which no bid price was specified will be assigned a price equal to negative one multiplied by the Forward Capacity Auction Starting Price.

For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants may elect either of the demand bid adjustment methods specified in Section III.13.2.8.3.3(b) for the resource by no later than five Business Days after the deadline for submission of offers composed of separate resources. If no such election is made, the adjustment applied shall be the method specified in Section III.13.2.8.3.3(b)(i).

III.13.2.8.3.3. Demand Bids Entered into the Substitution Auction.

If a resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, then any demand bid associated with the resource will not be further included in the substitution auction. If a resource is awarded a Capacity Supply Obligation in the primary auction-clearing process and the Capacity Clearing Price is less than ninety percent of the resource's test price as established pursuant to Section III.13.2.8.3.1A, then the resource's demand bid will not be included in the substitution auction.

Demand bids for resources that satisfy all of the criteria in Section III.13.2.8.3.1 to participate in the substitution auction will be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) For the substitution auction associated with the Capacity Commitment Period beginning on June 1, 2022, any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pairs.

(b) For substitution auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, a resource's demand bid will be adjusted using one of the following methods as elected pursuant to Section III.13.2.8.3.2:

(i) The portion of a resource's capacity that did not receive a Capacity Supply Obligation in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pair.

(ii) Any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the lowest priced price-quantity pair.

(c) After performing the modification specified in Sections III.13.2.8.3.3(a) or III.13.2.8.3.3(b), any price-quantity pairs in a resource's substitution auction demand bid with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface will have its price reduced to the Capacity Clearing Price for the resource's Capacity Zone or external interface.

Except as provided in Section III.13.2.5.2.1(c), a rationable demand bid will be entered into the substitution auction on behalf of any Proxy De-List Bid associated with a Permanent De-List Bid or Retirement De-List Bid. The demand bid quantity will equal the portion of the Proxy De-List Bid that was not cleared (received a Capacity Supply Obligation) in the first run of the primary auction-clearing process. The demand bid will have priority to clear before non-rationable demand bids.

III.13.3. Critical Path Schedule Monitoring.

III.13.3.1. Resources Subject to Critical Path Schedule Monitoring.

III.13.3.1.1. New Resources Electing Critical Path Schedule Monitoring.

A Project Sponsor that submits a critical path schedule for a New Capacity Resource in the qualification process may request that the ISO monitor that resource's compliance with its critical path schedule in accordance with the provisions of this Section III.13.3. The ISO will monitor the New Capacity Resource's compliance from the time the ISO approves the request until the resource achieves FCM Commercial Operation, loses its Capacity Supply Obligation pursuant to Section III.13.3.4A, or withdraws from critical path schedule monitoring pursuant to Section III.13.3.6.

In addition, a Lead Market Participant with a New Import Capacity Resource backed by one or more existing External Resources seeking to qualify for Capacity Commitment Period(s) prior to the Capacity Commitment Period associated with the Forward Capacity Auction for which it is qualifying must request monitoring under this Section III.13.3.1.1.

A request under this Section III.13.3.1.1 must be made in writing no later than five Business Days after the deadline for submission of the FCM Deposit pursuant to Section III.13.1.9.1.

III.13.3.1.2. New Resources Clearing in the Forward Capacity Auction.

For each new resource required to submit a critical path schedule in the qualification process, including but not limited to a New Generating Capacity Resource (pursuant to Section III.13.1.1.2.2), a New Import Capacity Resource backed by a new External Resource (pursuant to Section III.13.1.3.5), or a New Demand Capacity Resource (pursuant to Section III.13.1.4), if capacity from that resource clears in the Forward Capacity Auction, then the ISO shall monitor that resource's compliance with its critical path schedule in accordance with the provisions of this Section III.13.3 (regardless of whether the Project Sponsor requested monitoring pursuant to Section III.13.3.1.1) from the time that the Forward Capacity Auction is conducted until the resource achieves FCM Commercial Operation, loses its Capacity Supply Obligation pursuant to Section III.13.3.4A, or withdraws from critical path schedule monitoring pursuant to Section III.13.3.6.

III.13.3.1.3. New Resources Not Offering or Not Clearing in the Forward Capacity Auction.

If no capacity from a new resource that was required to submit a critical path schedule in the qualification process clears in the Forward Capacity Auction, or if such a resource does not submit an offer in the Forward Capacity Auction, then the ISO shall not monitor that resource's compliance with its critical path schedule after the Forward Capacity Auction unless the Project Sponsor previously requested pursuant to Section III.13.3.1.1 that the ISO continue to monitor that resource's compliance with its critical path schedule. However, if a New Generating Capacity Resource participated but did not clear in the Forward Capacity Auction either as: (i) a Conditional Qualified New Resource, or (ii) a New Generating Capacity Resource with a higher priority in the queue and overlapping interconnection impacts with a Conditional Qualified New Resource, the ISO will not continue to monitor that resource's compliance with its critical path schedule even if that resource requested critical path schedule monitoring pursuant to Section III.13.3.1.1.

III.13.3.2. Quarterly Critical Path Schedule Reports.

For each new resource that is being monitored for compliance with its critical path schedule, the Project Sponsor for that resource must provide a written critical path schedule report to the ISO no later than five Business Days after the end of each calendar quarter. If the Project Sponsor does not provide a written critical path schedule report to the ISO by the fifth Business Day after the end of the calendar quarter, then the ISO shall issue a notice thereof to the Project Sponsor. If the Project Sponsor fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.13.3.4A. Each critical path schedule report shall include the following:

III.13.3.2.1. Updated Critical Path Schedule.

The critical path schedule report must include a complete updated version of the critical path schedule as described in Section III.13.1.1.2.2.2, dated contemporaneously with the submission of the critical path schedule report. The updated critical path schedule should clearly indicate if the Project Sponsor is proposing to change any of the milestones or dates from the previously submitted version of the critical path schedule, and must include an explanation of any such proposed changes. In the critical path schedule report, the Project Sponsor should also explain in detail any proposed changes to the project design and the potential impact of such changes on the amount of capacity the resource will be able to provide.

III.13.3.2.2. Documentation of Milestones Achieved.

(a) For all new resources except for Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW (discussed in Section III.13.3.2.2(b)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Major Permits**. For each major permit described in the critical path schedule, the Project Sponsor shall provide documentation showing that the permit was applied for and obtained as described in the critical path schedule. For permit applications, this documentation could include a dated copy of the permit application or cover letter requesting the permit. For approved permits, this documentation could include a dated copy of the approved permit or letter granting the permit from the permitting authority.

(ii) **Project Financing Closing**. The Project Sponsor shall provide documentation showing that the sources of financing identified in the critical path schedule have committed to provide the amount of financing described in the critical path schedule. This documentation could include copies of commitment letters from the sources of financing.

(iii) **Major Equipment Orders**. For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the equipment was ordered as described in the critical path schedule. This documentation should include a copy of a dated confirmation of the order from the manufacturer or supplier. This documentation should confirm scheduled delivery dates consistent with milestone Section III.13.3.2.2(a)(vi).

(iv) **Substantial Site Construction.** The Project Sponsor shall provide documentation showing that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs.

(v) **Major Equipment Delivery**. For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the equipment was delivered to the project site and received as preliminarily acceptable as described in the critical path schedule. This documentation should include a copy of a dated confirmation of delivery to the project site.

(vi) **Major Equipment Testing.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the component was tested, including major systems testing as appropriate for the specific technology as described in the critical path schedule, and that the test results demonstrate the equipment's suitability to allow, in conjunction with other major components, subsequent operation of the project in accordance with the amount of capacity obligated from the resource in the Capacity Commitment Period in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning**. The Project Sponsor shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity obligated from the resource in the Capacity Commitment Period. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Project Sponsor is not required to provide documentation of Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) to the ISO as part of the ISO's critical path schedule monitoring. The ISO shall confirm that the resource has achieved Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) as described in the critical path schedule through the resource's compliance with the other relevant requirements of the Transmission, Markets and Services Tariff and the ISO New England System Rules.

(ix) **Transmission Upgrades**. If during the qualification process it was determined that transmission upgrades (including any upgrades identified in a re-study pursuant to Section 3.2.1.3 of Schedule 22, Section 1.7.1.3 of Schedule 23, or Section 3.2.1.3 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff) are needed for the new resource to complete its interconnection, then the Project Sponsor shall provide documentation showing that the transmission upgrades have been completed.

(b) For Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Substantial Project Completion**. The Project Sponsor shall provide documentation showing the total offered demand reduction value achieved as of target dates which are: (a) the cumulative percentage of total demand reduction value achieved on target date 1 occurring five weeks prior to the first Forward Capacity Auction after the Forward Capacity Auction in which the Demand Capacity Resource supplier's capacity award was made; (b) the cumulative percentage of total demand reduction value achieved on target date 2 occurring five weeks prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Demand Capacity Resource supplier's capacity award was made; and (c) target date 3 which is the date the resource is expected to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the Project Sponsor's New Demand Capacity Resource Qualification Package has achieved its full demand reduction value, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100 percent of the total demand reduction value must be complete.

(ii) **Additional Requirements**. For each customer and each prospective customer the Project Sponsor shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Asset has been registered with the ISO, then the Project Sponsor shall also provide the Asset identification number.

III.13.3.2.3. Additional Relevant Information.

The Project Sponsor must include in the critical path schedule report any other information regarding the status or progress of the project or any of the project milestones that might be relevant to the ISO's evaluation of the feasibility of the project being built in accordance with the critical path schedule or the feasibility that the project will achieve all its critical path schedule milestones no later than the start of the relevant Capacity Commitment Period.

III.13.3.2.4. Additional Information for Resources Previously Counted As Capacity.

For each resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4 or New Demand Capacity Resource pursuant to Section III.13.1.4.1 and clearing in that auction, the Project Sponsor must provide information in the critical path schedule report demonstrating: (a) the shedding of the resource's Capacity Supply Obligation in accordance with the provisions of Section III.13.1.1.2.2.5(c); and (b) that the relevant cost threshold (described in Sections III.13.1.1.1.2, III.13.1.1.1.3, and III.13.1.1.1.4) is being met.

III.13.3.3. Failure to Meet Critical Path Schedule.

If the ISO determines that any critical path schedule milestone date has been missed, or if the Project Sponsor proposes a change to any milestone date in a quarterly critical path schedule report (as described in Section III.13.3.2.1), then the ISO shall consult with the Project Sponsor to determine the impact of the missed milestone or proposed revision, and shall determine a revised date for the milestone and for any other milestones affected by the change. If a milestone date is revised for any reason, the ISO may require the Project Sponsor to submit a written report to the ISO on the fifth Business Day of each month until the revised milestone is achieved detailing the progress toward meeting the revised milestone. If the Project Sponsor does not provide a written critical path schedule report to the ISO on the fifth Business Day of a month, then the ISO shall issue a notice thereof to the Project Sponsor. If the Project Sponsor fails to provide the critical path schedule report within five Business Days of issuance of that notice, then the resource will be subject to termination pursuant to Section III.13.3.4A. Such a monthly reporting requirement, if imposed, shall be in addition to the quarterly critical path schedule reports described in Section III.13.3.2.

III.13.3.4. Covering Capacity Supply Obligations.

(a) If a capacity supplier determines that a resource may not be able to demonstrate its ability to deliver the full amount of its Capacity Supply Obligation, the capacity supplier may take actions to cover all or part of the Capacity Supply Obligation for any portion of the Capacity Commitment Period, as follows:

(i) A capacity supplier may cover its Capacity Supply Obligation through reconfiguration auctions as described in Section III.13.4.

(ii) A capacity supplier may cover its Capacity Supply Obligation through one or more Capacity Supply Obligation Bilaterals, subject to the satisfaction of the requirements in Section III.13.5.

(iii) A capacity supplier that has qualified a resource pursuant to Section III.13.1.1.1.2 may cover its Capacity Supply Obligation by electing, no later than ten Business Days prior to the offer and bid deadline for the third annual reconfiguration auction prior to the start of the applicable Capacity Commitment Period, to have the resource that was previously counted as a capacity resource cover the Capacity Supply Obligation of the New Generating Capacity Resource for up to two Capacity Commitment Periods. If an election is made to have the resource that was previously counted as a capacity resource cover the Capacity Supply Obligation of the New Generating Capacity Resource, the capacity supplier with the resource that was previously counted as a capacity resource shall be required to comply with the requirements set forth in Section III.13.6.1 so long as it continues to cover for the New Generating Capacity Resource.

(b) During a Capacity Commitment Period, a failure to cover charge will apply to any capacity resource that has not demonstrated the ability to deliver the full amount of its Capacity Supply Obligation by the end of an Obligation Month. The failure to cover charge is the difference between a resource's monthly Capacity Supply Obligation and its Maximum Demonstrated Output, multiplied by the Failure to Cover Charge Rate, where:

Maximum Demonstrated Output Period

Maximum Demonstrated Output Period is the period beginning six years prior to the start of the applicable Capacity Commitment Period and ending with the most recently completed calendar month in the Capacity Commitment Period, including all prior months in the Capacity Commitment Period.

Provided that, for a resource that has previously been counted as a capacity resource and for which an election has been made to participate as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2, and for which a cover election has been made pursuant to Section III.13.3.4(a)(iii), then: (1) the Maximum Demonstrated Output Period will be the Maximum Demonstrated Output Period of the resource that has been previously counted as capacity, and; (2) the Maximum Demonstrated Output Period of the New Generating Capacity Resource will begin on the earlier of: (i) the date that the resource that has previously been counted as a capacity resource began any outage as provided in Section III.13.1.1.1.2, and; (ii) the date that the New

Generating Capacity Resource commenced Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff).

Failure to Cover Charge Rate

For Capacity Commitment Periods beginning prior to June 1, 2022, the Failure to Cover Charge Rate for a Capacity Zone is the higher of the Capacity Clearing Price and the clearing price in any annual reconfiguration auction for that Capacity Commitment Period.

For Capacity Commitment Periods beginning on or after June 1, 2022, the Failure to Cover Charge Rate for a Capacity Zone is the price determined by a second clearing of the third annual reconfiguration auction prior to the start of the Capacity Commitment Period in which the aggregated zonal quantities of undemonstrated Capacity Supply Obligation, as of the completion of the third annual reconfiguration auction, and as determined pursuant to Section III.13.3.4 (b), are included as demand bids at the Forward Capacity Auction Starting Price for each applicable Capacity Zone.

Provided that, if an existing resource is covering for a New Generating Capacity Resource pursuant to Section III.13.3.4(a)(iii), then the undemonstrated Capacity Supply Obligation for the New Generating Capacity Resource is the difference between the existing resource's Maximum Demonstrated Output and the new resource's Capacity Supply Obligation.

Maximum Demonstrated Output

The Maximum Demonstrated Output is the sum of the highest output levels achieved by each Generator Asset associated with a Generating Capacity Resource, each Demand Response Asset associated with an Active Demand Capacity Resources, and assets associated with a Seasonal Peak Demand Resource or On-Peak Demand Resource, during the Maximum Demonstrated Output Period as specified below. The minimum Maximum Demonstrated Output for all assets is zero.

Provided that, if a resource that was previously counted as capacity is covering for a New Generating Capacity Resource pursuant to Section III.13.3.4(a)(iii), then the Maximum Demonstrated Output is the sum of the highest aggregate output level achieved by each asset associated with the resource that has previously been counted as capacity during the Maximum Demonstrated Output Period.

At the asset level, Maximum Demonstrated Output is calculated as follows:

Demand Response Assets associated with an Active Demand Capacity Resource: The Maximum Demonstrated Output for dates occurring prior to June 1, 2018 is the highest audit value in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses. The Maximum Demonstrated Output for dates occurring on or after to June 1, 2018 will be equal to the highest demand reduction calculated, pursuant to Section III.8.4, in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses for non-Net Supply.

Distributed Generation associated with a Seasonal Peak Demand Resource or an On-Peak Demand Resource: The Maximum Demonstrated Output is the highest hourly metered output in the Maximum Demonstrated Output Period after the resource has completed testing and has achieved commercial operation, increased by average avoided peak transmission and distribution losses for non-Net Supply.

Load Management associated with a Seasonal Peak Demand Resource or an On-Peak Demand Resource: The Maximum Demonstrated Output is the highest hourly demand reduction value in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses for non-Net Supply.

Energy Efficiency associated with a Seasonal Peak Demand Resource or an On-Peak Demand Resource: The Maximum Demonstrated Output is the highest reported monthly performance value in the Maximum Demonstrated Output Period increased by average avoided peak transmission and distribution losses.

Generator Assets: The Maximum Demonstrated Output for dates occurring prior to March 1, 2017 is the highest hourly Revenue Quality Metering in the Maximum Demonstrated Output Period beginning on or after Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff). The Maximum Demonstrated Output for dates occurring on or after March 1, 2017 is the highest Metered Quantity for Settlement in the Maximum Demonstrated Output Period beginning on or after Commercial

Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff).

If a single Generator Asset is split into two or more new Generator Assets, the Maximum Demonstrated Output associated with the single Generation Asset will be prorated among the new assets based on their summer maximum net output. If multiple Generator Assets are consolidated to fewer assets, the Maximum Demonstrated Output of the Generator Assets that are being consolidated will be allocated to the consolidated assets based on the summer maximum net output.

Import Capacity Resources: For an Import Capacity Resource that is backed by external generation that has not achieved commercial operation at the time of qualification, in part or entirely, the Maximum Demonstrated Output is the highest revenue quality metered output for a five-minute or greater interval after the resource has completed testing and has achieved commercial operation. Provided that, the Maximum Demonstrated Output of an Import Capacity Resource associated with an Elective Transmission Upgrade may be limited by the highest demonstrated capability of the Elective Transmission Upgrade after the Elective Transmission Upgrade has completed testing and has achieved commercial operation.

III.13.3.4A Termination of Capacity Supply Obligations.

If a Project Sponsor fails to comply with the requirements of Sections III.13.3.2 or III.13.3.3, or if a Project Sponsor covers a Capacity Supply Obligation for two Capacity Commitment Periods, or if, as a result of milestone date revisions, the date by which a resource will have achieved all its critical path schedule milestones is more than two years after the beginning of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation, then the ISO, after consultation with the Project Sponsor, shall have the right, through a filing with the Commission, to terminate the resource's Capacity Supply Obligation for any future Capacity Commitment Periods and the resource's right to any payments associated with that Capacity Supply Obligation in the Capacity Commitment Period, and to adjust the resource's qualified capacity for participation in the Forward Capacity Market; provided that, where a Project Sponsor voluntarily withdraws its resource from critical path schedule monitoring in accordance with Section III.13.3.6, no filing with the Commission shall be necessary to terminate the resource's Capacity Supply Obligation. Upon Commission ruling, the Project Sponsor shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation. If in these circumstances, however, the ISO does not take steps to terminate the resource's Capacity Supply Obligation and instead permits the Project Sponsor to continue to cover its Capacity Supply Obligation, such continuation shall be subject to the ISO's right to revoke that permission and to file with the Commission to terminate the resource's Capacity Supply Obligation, and subject to continued reporting by the Project Sponsor as described in this Section III.13.3.

If a resource's Capacity Supply Obligation that was acquired in a substitution auction at a negative price is withdrawn or terminated, the Project Sponsor shall remain obligated for any settlement charges associated with the terminated Capacity Supply Obligation for the Capacity Commitment Period.

III.13.3.5. Termination of Interconnection Agreement.

If the ISO terminates, or files with the Commission to terminate, a resource's Capacity Supply Obligation as described in Section III.13.3.4A, the ISO shall have the right to terminate the Interconnection Agreement with that resource through a filing with the Commission and upon Commission ruling. If the Project Sponsor continues to cover all of its Capacity Supply Obligations while challenging such termination before the Commission, it shall retain its Queue Position.

III.13.3.6. Withdrawal from Critical Path Schedule Monitoring.

A Project Sponsor may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO. The ISO also may deem a resource withdrawn from critical path schedule monitoring if the Project Sponsor does not adhere to the requirements of this Section III.13.3. Any resource withdrawn from critical path schedule monitoring shall be subject to the provisions of Section III.13.3.4A.

III.13.3.7 Request to Defer Capacity Supply Obligation

A resource that has not yet achieved FCM Commercial Operation and that is subject to critical path schedule monitoring by the ISO pursuant to this Section III.13.3 may seek to defer the applicability of its entire Capacity Supply Obligation by one year pursuant to the provisions of this Section III.13.3.7.

A Project Sponsor seeking such a deferral must notify the ISO in writing no later than the first Business Day in September of the year prior to the third annual reconfiguration auction for the Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If, after consultation with the Project Sponsor, the ISO determines that the absence of the capacity in the first Capacity Commitment Period in which the resource has a Capacity Supply Obligation, as well as in the subsequent Capacity Commitment Period, would result in the violation of any NERC or NPCC (or their successors) criteria or of the ISO New England System Rules, not solely that it may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for the Capacity Zone, then the ISO will review the specific reliability need with and seek feedback from the Reliability Committee and provide the Project Sponsor with a written determination to that effect within 30 days of the Project Sponsor's notification to the ISO.

If the ISO provides such a written determination, then the Project Sponsor may file with the Commission, no later than the first Business Day in November of the year prior to the third annual reconfiguration auction, a request to defer the applicability of its Capacity Supply Obligation by one year. Any such filing must include the ISO's written determination, and must also demonstrate that the deferral is critical to the resource's ability to achieve FCM Commercial Operation and that the reasons for the deferral are beyond the control of the Project Sponsor.

If the Commission approves the request, all of the rights, obligations, payments, and charges associated with the Capacity Supply Obligation described in Sections III.13.3.4(b), III.13.6 and III.13.7 shall only apply beginning one year after the start of the Capacity Commitment Period in which the resource has a Capacity Supply Obligation. Notwithstanding any other provision of this Section III.13, if the resource achieves FCM Commercial Operation prior to the deferred date, it will not be eligible to receive revenue in the Forward Capacity Market until the deferred date. Beginning on the deferred date, all of the rights, obligations, payments, and charges associated with the Capacity Supply Obligation shall apply, and the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) associated with the Forward Capacity Auction in which the resource cleared as a new resource shall apply for the full duration of the Capacity Supply Obligation (including multi-year elections made pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7). A Project Sponsor will not take actions to cover the resource's Capacity Supply Obligation for the deferral period as described in Section III.13.3.4(a), but the other requirements of III.13.3, including all reporting requirements and the ISO's right to seek termination, shall continue to apply during the deferral period. Upon Commission approval of the deferral, the resource may not participate in any reconfiguration auctions or Capacity Supply Obligation Bilaterals for any portion of the deferral period. Beginning at 8:00 a.m. (Eastern Time) 30 days after Commission approval of the request, the Project Sponsor shall be required to provide an additional amount of financial assurance as described in Section VII.B.2.c of the ISO New England Financial Assurance Policy.

Notwithstanding any other provision of this Section III.13, if any of the resource's Capacity Supply Obligation in the deferral period was shed in a reconfiguration auction or Capacity Supply Obligation Bilateral prior to Commission approval of the deferral request, then the resource's settlements shall be adjusted by the ISO to ensure that the resource does not receive any payments associated with that transaction in excess of the charges associated with that transaction; the resource will be responsible for any charges in excess of payments.

III.13.3.8 FCM Commercial Operation.

A resource (or portion thereof) achieves FCM Commercial Operation when (1) the ISO has determined that the resource (or portion thereof) has achieved all its critical path schedule milestones, including completion of any transmission upgrades necessary for the resource to obtain the requisite interconnection service; and (2) the ISO verifies the resource's (or a portion of the resource's) summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating).

(a) For a Generating Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation as soon as practicable following the ISO's verification of the resource's summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating), which may take place in any month of the year. The ISO shall verify the summer capacity rating of a Generating Capacity Resource that is an Intermittent Power Resource following no fewer than 30 consecutive calendar days of operation (for periods from October 1 through May 31, a Market Participant must request such verification).

(b) For a Demand Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation upon verifying that the Demand Capacity Resource described in the New Demand Capacity Resource Qualification Package has achieved its full demand reduction value, subject to the requirements of Section III.13.6.1.5.3(b).

(c) For an Import Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation upon demonstration that the Import Capacity Resource described in the New Capacity Qualification Package has achieved its full Qualified Capacity.

III.13.4. Reconfiguration Auctions.

For each Capacity Commitment Period, the ISO shall conduct annual and monthly reconfiguration auctions as described in this Section III.13.4. Reconfiguration auctions only permit the trading of Capacity Supply Obligations; load obligations are not traded in reconfiguration auctions. Each reconfiguration auction shall use a static double auction (respecting the interface limits and capacity requirements modeled as specified in Sections III.13.4.5 and III.13.4.7) to clear supply offers (i.e., offers to assume a Capacity Supply Obligation) and demand bids (i.e., bids to shed a Capacity Supply Obligation) for each Capacity Zone included in the reconfiguration auction. Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected. Resources that are able to meet the requirements in other Capacity Zones shall be allowed to clear to meet such requirements, subject to the constraints modeled in the auction.

III.13.4.1. Capacity Zones Included in Reconfiguration Auctions.

Each reconfiguration auction associated with a Capacity Commitment Period shall include each of, and only, the final Capacity Zones and external interfaces as determined through the Forward Capacity Auction for that Capacity Commitment Period, as described in Section III.13.2.3.4.

III.13.4.2. Participation in Reconfiguration Auctions.

Each supply offer and demand bid in a reconfiguration auction must be associated with a specific resource, and must satisfy the requirements of this Section III.13.4.2. All resource types may submit supply offers and demand bids in reconfiguration auctions. In accordance with Section III.A.9.2 of ***Appendix A*** of this Market Rule 1, supply offers and demand bids submitted for reconfiguration auctions shall not be subject to mitigation by the Internal Market Monitor. A supply offer or demand bid submitted for a reconfiguration auction shall not be limited by the associated resource's Economic Minimum Limit. Offers composed of separate resources may not participate in reconfiguration auctions. Participation in any reconfiguration auction is conditioned on full compliance with the applicable financial assurance requirements as provided in the ISO New England Financial Assurance Policy at the time of the offer and bid deadline. For annual reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 30 days prior to that deadline. No later than 15 days before the offer and bid deadline for an annual reconfiguration auction, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions, the offer and bid deadline will be announced by the ISO no later than 10 Business Days prior to that deadline. Upon issuance of the monthly bilateral results for the associated

Obligation Month, the ISO shall notify each resource of the amount of capacity that it may offer or bid in that monthly auction, as calculated pursuant to this Section III.13.4.2. For monthly reconfiguration auctions in which the most recently approved Winter Seasonal Claimed Capability established as of the fifth Business Day in June of the relevant Capacity Commitment Period is greater than the Winter ARA Qualified Capacity for the third annual reconfiguration auction, the ISO shall apply the greater of these two values to offer limits starting with the first monthly reconfiguration auction in the winter delivery period for the relevant Capacity Commitment Period, limited, as applicable, by the resource's CNR Capability.

III.13.4.2.1. Supply Offers.

Submission of supply offers in reconfiguration auctions shall be governed by this Section III.13.4.2.1. All supply offers in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the resource, the amount of capacity offered in MW, and the price, in dollars per kW/month. In no case may capacity associated with a Retirement De-List Bid or a Permanent De-List Bid that cleared in the Forward Capacity Auction, or a demand bid that cleared in a substitution auction, for a Capacity Commitment Period be offered in a reconfiguration auction for that, or any subsequent, Capacity Commitment Period, or any portion thereof. In no case may capacity associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction for a Capacity Commitment Period be offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof.

III.13.4.2.1.1. Amount of Capacity That May Be Submitted in a Supply Offer in an Annual Reconfiguration Auction.

For each month of the Capacity Commitment Period associated with the annual reconfiguration auction, the ISO shall calculate the difference between the Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, and the amount of capacity from that resource that is already subject to a Capacity Supply Obligation for the month. The minimum of these 12 values shall be the amount of capacity up to which a resource may submit a supply offer in the annual reconfiguration auction.

III.13.4.2.1.2. Calculation of Summer ARA Qualified Capacity and Winter ARA Qualified Capacity.

III.13.4.2.1.2.1. First Annual Reconfiguration Auction and Second Annual Reconfiguration Auction.

III.13.4.2.1.2.1.1. Generating Capacity Resources Other than Intermittent Power Resources.

III.13.4.2.1.2.1.1.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the higher of the resource's summer Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any summer Seasonal Claimed Capability values for summer periods completed after the Existing Capacity Retirement Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and where the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.1.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the higher of the resource's winter Qualified Capacity as calculated for the Forward Capacity Auction for that Capacity Commitment Period and any winter Seasonal Claimed Capability values for winter periods completed after the Existing Capacity Retirement Deadline for the Forward Capacity Auction for the Capacity Commitment Period and before the start of the Capacity Commitment Period. The amount of capacity described in this Section III.13.4.2.1.2.1.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and where the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2. Intermittent Power Resources.

III.13.4.2.1.2.1.2.1. Summer ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined summer Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.2.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined winter Qualified Capacity. The amount of capacity described in this Section III.13.4.2.1.2.1.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.3. Import Capacity Resources Backed By an External Control Area.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to its summer Qualified Capacity and winter Qualified Capacity, respectively, as determined for the Forward Capacity Auction for that Capacity Commitment Period.

III.13.4.2.1.2.1.3.1. Import Capacity Resources Backed by One or More External Resources.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be the greater of:

(a) the summer Qualified Capacity and winter Qualified Capacity, respectively, as determined for the Forward Capacity Auction for that Capacity Commitment Period; and

(b) the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October and, if submitted for a New Import Capacity Resource backed by one or more External Resources, also subject to the satisfaction of the requirements in Sections III.13.1.3.5.1(b), III.13.1.3.5.2, and III.13.3.1.1 and the relevant financial assurance requirements as described in Section III.13.1.9 and the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.1.4. Demand Capacity Resources.

III.13.4.2.1.2.1.4.1. Summer ARA Qualified Capacity.
For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Capacity Resource shall be determined as follows.

(a) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the sum of the values determined pursuant to subsections (i) and (ii) below:

(i) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined summer Qualified Capacity.

(ii) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (1) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (2) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (3) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

(b) For Demand Capacity Resources composed of Energy Efficiency measures, the lesser of the values determined pursuant to subsections (i) and (ii) below:

(i) The sum of the most recently-determined summer demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to the start of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses) and any summer capacity that has not yet achieved FCM Commercial Operation that satisfies the criteria found in subsection (a)(ii) above.

(ii) The amount of summer capacity that qualified for the Forward Capacity Auction as a New Demand Capacity Resource (excluding any capacity that is terminated or that will retire or permanently de-list prior to the start of the relevant Capacity Commitment Period) that is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period.

III.13.4.2.1.2.1.4.2. Winter ARA Qualified Capacity.

For the first and second annual reconfiguration auctions associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Capacity Resource shall be determined as follows.

(a) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the sum of the values determined pursuant to subsections (i) and (ii) below:

(i) For capacity that has achieved FCM Commercial Operation, the resource's most recently-determined winter Qualified Capacity.

(ii) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (1) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (2) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (3) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

(b) For Demand Capacity Resources composed of Energy Efficiency measures, the lesser of the values determined pursuant to subsections (i) and (ii) below:

(i) The sum of the most recently-determined winter demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to the start of the winter period of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses) and any winter capacity that has not yet achieved FCM Commercial Operation that satisfies the criteria found in subsection (a)(ii) above.

(ii) The amount of winter capacity that qualified for the Forward Capacity Auction as a New Demand Capacity Resource (excluding any capacity that is terminated or that will retire or permanently de-list prior to the start of the relevant Capacity Commitment Period) that is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period.

III.13.4.2.1.2.2. Third Annual Reconfiguration Auction.

III.13.4.2.1.2.2.1. Generating Capacity Resources other than Intermittent Power Resources.

III.13.4.2.1.2.2.1.1. Summer ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the resource's summer Seasonal Claimed Capability value in effect after the most recently completed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.1.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Generating Capacity Resource that is not an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the resource's winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.1.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2. Intermittent Power Resources.

III.13.4.2.1.2.2.2.1. Summer ARA Qualified Capacity.
For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the lesser of its most recently-determined summer Qualified Capacity and its summer Seasonal Claimed Capability value in effect after the most recently competed summer period. The amount of capacity described in this Section III.13.4.2.1.2.2.2.1(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.2.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Intermittent Power Resource shall be the sum of the values determined pursuant to subsections (a) and (b) below, limited, as applicable, by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f):

(a) For capacity that has achieved FCM Commercial Operation, the lesser of its most recently-determined winter Qualified Capacity and its winter Seasonal Claimed Capability value in effect after the most recently completed winter period. The amount of capacity described in this Section III.13.4.2.1.2.2.2.2(a) shall be zero, however, where the resource cleared in the Forward Capacity Auction for the Capacity Commitment Period as a new resource pursuant to Section III.13.1.1.1.2 and the project has not achieved FCM Commercial Operation.

(b) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (i) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (ii) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (iii) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.3. Import Capacity Resources.

III.13.4.2.1.2.2.3.1 Import Capacity Resources Backed by an External Control Area.
For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its summer Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October. For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of an Import Capacity Resource shall be equal to the lesser of its winter Qualified Capacity as determined for the Forward Capacity Auction for that Capacity Commitment Period and the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October.

III.13.4.2.1.2.2.3.2. Import Capacity Resources Backed by One or More External Resources.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity and Winter ARA Qualified Capacity of an Import Capacity Resource backed by one or more External Resources shall be the lesser of:

(a) the summer Qualified Capacity and winter Qualified Capacity, respectively, as determined by the most recent Forward Capacity Auction that does not reflect a change to the Import Capacity Resource applicable to that Capacity Commitment Period; and

(b) the amount of capacity available to back the import, if submitted by the Lead Market Participant and approved by the ISO by the fifth Business Day in October and, if submitted for a New Import Capacity Resource backed by one or more External Resources, also subject to the satisfaction of the requirements in Sections III.13.1.3.5.1(b), III.13.1.3.5.2, and III.13.3.1.1 and the relevant financial assurance requirements as described in Section III.13.1.9 and the ISO New England Financial Assurance Policy.

III.13.4.2.1.2.2.4. Demand Capacity Resources.

III.13.4.2.1.2.2.4.1. Summer ARA Qualified Capacity.
For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Summer ARA Qualified Capacity of a Demand Capacity Resource shall be determined as follows.

(a) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the sum of the values determined pursuant to subsections (i) and (ii) below:

(i) For capacity that has achieved FCM Commercial Operation, the lesser of: (1) its most recently-determined summer Qualified Capacity and (2) its summer Seasonal DR Audit value or summer Passive DR Audit value in effect at the time of qualification for the third annual reconfiguration auction.

(ii) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (1) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (2) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (3) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

(b) For Demand Capacity Resources composed of Energy Efficiency measures, the lesser of the values determined pursuant to subsections (i) and (ii) below:

(i) The sum of the most recently-determined summer demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to the start of the relevant Capacity Commitment Period, and increased by average avoided peak transmission and distribution losses) and any summer capacity that has not yet achieved FCM Commercial Operation that satisfies the criteria found in subsection (a)(ii) above.

(ii) The amount of summer capacity that qualified for the Forward Capacity Auction as a New Demand Capacity Resource (excluding any capacity that will retire or permanently de-list prior to the start of the relevant Capacity Commitment Period) provided that the resource is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period.

III.13.4.2.1.2.2.4.2. Winter ARA Qualified Capacity.

For the third annual reconfiguration auction associated with a Capacity Commitment Period, the Winter ARA Qualified Capacity of a Demand Capacity Resource shall be determined as follows.

(a) For Demand Capacity Resources other than those composed of Energy Efficiency measures, the sum of the values determined pursuant to subsections (i) and (ii) below:

(i) For capacity that has achieved FCM Commercial Operation, the lesser of: (1) its most recently-determined winter Qualified Capacity and (2) its winter Seasonal DR Audit value or winter Passive DR Audit value in effect at the time of qualification for the third annual reconfiguration auction.

(ii) Any amount of capacity that has not yet achieved FCM Commercial Operation but: (1) is being monitored by the ISO pursuant to the provisions of Section III.13.3; (2) is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period; and (3) for which the Lead Market Participant or Project Sponsor has met all relevant financial assurance requirements as described in Section III.13.1.9 and in the ISO New England Financial Assurance Policy.

(b) For Demand Capacity Resources composed of Energy Efficiency measures, the lesser of the values determined pursuant to subsections (i) and (ii) below:

(i) The sum of the most recently-determined winter demand reduction values of the resource's installed Energy Efficiency measures (excluding any capacity that will retire or permanently de-list, or whose Measure Life will expire, prior to the start of the winter period of the relevant Capacity Commitment Period and increased by average avoided peak transmission and distribution losses) and any winter capacity that has cleared in a Forward Capacity Auction and not yet achieved FCM Commercial Operation that satisfies the criteria found in subsection (a)(ii) above.

(ii) The amount of winter capacity that qualified for the Forward Capacity Auction as a New Demand Capacity Resource (excluding any capacity that will retire or permanently de-list prior to the start of the relevant Capacity Commitment Period) provided that the resource is expected to achieve all its critical path schedule milestones prior to the start of the relevant Capacity Commitment Period.

III.13.4.2.1.3. Adjustment for Significant Decreases in Capacity.

For each month of the Capacity Commitment Period associated with the third annual reconfiguration auction, for each resource that has achieved FCM Commercial Operation, the ISO shall subtract the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity, as applicable, from the amount of capacity from the resource that is subject to a Capacity Supply Obligation for the month. For the month associated with the greatest of these 12 values (for Capacity Commitment Periods beginning on or before June 1, 2019) or the least of these 12 values (for Capacity Commitment Periods beginning on or after June 1, 2020), if the resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity (as applicable) is below the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month by:

(1) for Capacity Commitment Periods beginning on or before June 1, 2019, more than the lesser of:

 (i) 20 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or;

(ii) 40 MW;

(2) for Capacity Commitment Periods beginning on June 1, 2020, June 1, 2021 and June 1, 2022, more than the lesser of:

(i) the greater of 20 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or two MW, or;

(ii) 40 MW;

(3) for Capacity Commitment Periods beginning on or after June 1, 2023, more than the lesser of:

(i) the greater of 10 percent of the amount of capacity from that resource that is subject to a Capacity Supply Obligation for that month or two MW, or;

(ii) 10 MW;

then the following provisions shall apply:

(a) The Lead Market Participant may submit a written plan to the ISO with any necessary supporting documentation describing the measures that will be taken and demonstrating that the resource will be able to provide an amount of capacity consistent with its total Capacity Supply Obligation for the Capacity Commitment Period by the start of all months in that Capacity Commitment Period in which the resource has a Capacity Supply Obligation. If submitted, such a plan must be received by the ISO no later than 10 Business Days after the ISO has notified the Lead Market Participant of its Summer ARA Qualified Capacity and Winter ARA Qualified Capacity for the third annual reconfiguration auction.

(b) If no such plan as described in Section III.13.4.2.1.3(a) is timely submitted to the ISO, or if such a plan is timely submitted but the ISO determines that the plan does not demonstrate that the resource will be able to provide the necessary amount of capacity by the start of all months in the Capacity Commitment Period in which the resource has a Capacity Supply Obligation, then the ISO shall enter a demand bid at the Forward Capacity Auction Starting Price on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) in the third annual reconfiguration auction in an amount equal to:

(1) for Capacity Commitment Periods beginning prior to June 1, 2020, the greatest of the 12 monthly values determined pursuant to this Section III.13.4.2.1.3;

(2) for Capacity Commitment Periods beginning on June 1, 2020, June 1, 2021 and June 1, 2022, where the Capacity Supply Obligation and Qualified Capacity values are those for the month in which the values as determined pursuant to Section III.13.4.2.1.3 vary the least, the greater of:

(i) the resource's Capacity Supply Obligation minus (Qualified Capacity divided by 0.8), and;

(ii) the resource's Capacity Supply Obligation minus Qualified Capacity minus 40 MW;

(3) for Capacity Commitment Periods beginning on or after June 1, 2023, where the Capacity Supply Obligation and Qualified Capacity values are those for the month in which the values as determined pursuant to Section III.13.4.2.1.3 vary the least, the greater of:

(i) the resource's Capacity Supply Obligation minus (Qualified Capacity divided by 0.9), and;

(ii) the resource's Capacity Supply Obligation minus Qualified Capacity minus 10 MW.

III.13.4.2.1.4. Amount of Capacity That May Be Submitted in a Supply Offer in a Monthly Reconfiguration Auction.

A resource may not submit a supply offer for a monthly reconfiguration auction unless it is expected to achieve FCM Commercial Operation prior to the end of the relevant Obligation Month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a supply offer for that reconfiguration auction in an amount up to the absolute value of its Capacity Supply Obligation. A resource may not submit a supply offer for a monthly reconfiguration auction if it is on an approved outage during that month. The amount of capacity up to which a resource may submit a supply offer in a monthly reconfiguration auction shall be the difference (but in no case less than zero) between the values determined pursuant to subsections (a) and (b) below:

(a) The resource's Summer ARA Qualified Capacity or Winter ARA Qualified Capacity as adjusted pursuant to Section III.13.4.2, as applicable, for the auction month for the third annual reconfiguration auction for the relevant Capacity Commitment Period or, where the resource did not qualify for the third annual reconfiguration auction for the relevant Capacity Commitment Period, the quantity of MW either being monitored by the ISO in accordance with Section III.13.3 (provided that all applicable Financial Assurance requirements have been met and the resource is expected to achieve all its critical path schedule milestones prior to the end of the relevant Obligation Month in accordance with posted schedules) or the amount of capacity that achieved all its critical path schedule milestones after the third annual reconfiguration qualification deadline; provided that the value determined pursuant to this subsection (a) shall be limited by the resource's CNR Capability and any relevant overlapping interconnection impacts as described in Section III.13.1.1.2.3(f) or, for a Demand Capacity Resource, the amount of Qualified Capacity for the relevant Capacity Commitment Period.

(b) The amount of capacity from that resource that is already subject to a Capacity Supply Obligation for that month.

III.13.4.2.1.5. ISO Review of Supply Offers.

Supply offers in reconfiguration auctions shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's reviews will consider the location and operating and rating limitations of resources associated with cleared supply offers to ensure reliability standards will remain satisfied if the offer is accepted. The ISO shall reject supply offers that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria, or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction. The ISO's reliability reviews will assess such offers, beginning with the marginal resource, based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset or Demand Response Resource outage information, and will include transmission security studies. Supply offers that cannot meet the applicable reliability needs will be rejected in their entirety and the resource will not be rejected in part. Rejected resources will not be further included in clearing the reconfiguration auction and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.2.2. Demand Bids in Reconfiguration Auctions.

Submission of demand bids in reconfiguration auctions shall be governed by this Section III.13.4.2.2. All demand bids in reconfiguration auctions shall be submitted by the Project Sponsor or Lead Market Participant, and shall specify the amount of capacity bid in MW, and the price, in dollars per kW/month.

(a) To submit a demand bid in a reconfiguration auction, a resource must have a Capacity Supply Obligation for the Capacity Commitment Period (or portion thereof, as applicable) associated with that reconfiguration auction. Where capacity associated with a Self-Supplied FCA Resource that cleared in the Forward Capacity Auction for the Capacity Commitment Period is offered in a reconfiguration auction for that Capacity Commitment Period, or any portion thereof, a resource acquiring a Capacity Supply Obligation shall not as a result become a Self-Supplied FCA Resource.

(b) Each demand bid submitted to the ISO for reconfiguration auction shall be no greater than the amount of the resource's capacity that is already obligated for the Capacity Commitment Period (or portion thereof, as applicable) as of the offer and bid deadline for the reconfiguration auction.

(c) All demand bids in reconfiguration auctions shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's reviews will consider the location and operating and rating limitations of resources associated with demand bids that would otherwise clear to ensure reliability standards will remain satisfied if the committed capacity is withdrawn. The ISO shall reject demand bids that would otherwise clear in a reconfiguration auction that will result in a violation of any NERC or NPCC criteria or ISO New England System Rules during the Capacity Commitment Period associated with the reconfiguration auction, provided that for annual reconfiguration auctions associated with a Capacity Commitment Period that begins on or after June 1, 2018, the ISO shall not reject a demand bid solely on the basis that acceptance of the demand bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs). For monthly reconfiguration auctions, the ISO shall obtain and consider information from the Local Control Center regarding whether the capacity associated with demand bids that would otherwise clear from resources with a Capacity Supply Obligation is needed for local system conditions. The ISO's reliability reviews will assess such bids, beginning with the marginal resource, based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset or Demand Response Resource outage information, and will include transmission security studies. Where the applicable reliability needs cannot be met if a Demand Bid is cleared, such Demand Bids will be rejected in their entirety and the resource will not be rejected in part. Demand Bids from rejected resources will not be further included in clearing the reconfiguration auction, and the Lead Market Participant or Project Sponsor, as appropriate, shall be notified as soon as practicable after the reconfiguration auction of the rejection and of the reliability need prompting such rejection.

III.13.4.3. [Reserved.]

III.13.4.4. Clearing Offers and Bids in Reconfiguration Auctions.

All supply offers and demand bids may be cleared in whole or in part in all reconfiguration auctions. If after clearing, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.4.5. Annual Reconfiguration Auctions.

Except as provided below, after the Forward Capacity Auction for a Capacity Commitment Period, and before the start of that Capacity Commitment Period, the ISO shall conduct three annual reconfiguration auctions for capacity commitments covering the whole of that Capacity Commitment Period. For each annual reconfiguration auction, the capacity demand curves, New England Control Area and Capacity Zone capacity requirements and external interface limits, as updated pursuant to Section III.12, shall be modeled in the auction consistent with the Forward Capacity Auction for the associated Capacity Commitment Period. For purposes of the annual reconfiguration auctions, the Forward Capacity Auction Starting Price used to define the System-Wide Capacity Demand Curve shall be the Forward Capacity Auction Starting Price associated with the Forward Capacity Auction for the same Capacity Commitment Period addressed by the reconfiguration auction.

III.13.4.5.1. Timing of Annual Reconfiguration Auctions.

The first annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of June that is approximately 24 months before the start of the Capacity Commitment Period. The second annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of August that is approximately 10 months before the start of the Capacity Commitment Period. The third annual reconfiguration auction for the Capacity Commitment Period shall be held in the month of March that is approximately 3 months before the start of the Capacity Commitment Period.

III.13.4.5.2. Acceleration of Annual Reconfiguration Auction.

If the difference between the forecasted Installed Capacity Requirement (net of HQICCs) for a Capacity Commitment Period and the amount of capacity obligated for that Capacity Commitment Period is sufficiently large, then the ISO may, upon reasonable notice to Market Participants, conduct an annual reconfiguration auction as much as six months earlier than its normally-scheduled time.

III.13.4.6. [Reserved.]

III.13.4.7. Monthly Reconfiguration Auctions.

Prior to each month in the Capacity Commitment Period, the ISO shall conduct a monthly reconfiguration auction for whole-month capacity commitments during that month. For each monthly reconfiguration auction for Capacity Commitment Periods beginning before June 1, 2020, the Local Sourcing Requirement and Maximum Capacity Limit applicable for each Capacity Zone and external interface limits, as updated pursuant to Section III.12, shall be modeled as constraints in the auction. For each monthly reconfiguration auction for Capacity Commitment Periods beginning or after June 1, 2020, the truncation points for import-constrained Capacity Zones and export-constrained Capacity Zones specified in Section III.13.2.2.2 and Section III.13.2.2.3, and external interface limits, as updated pursuant to

Section III.12, shall be modeled as constraints in the auction. The System-Wide Capacity Demand Curve is not modeled in monthly reconfiguration auctions.

III.13.4.8. Adjustment to Capacity Supply Obligations.

For each supply offer that clears in a reconfiguration auction, the resource's Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be increased by the amount of capacity that clears. For each demand bid that clears in a reconfiguration auction, the resource's Capacity Supply Obligation for the relevant Capacity Commitment Period (or portion thereof, as applicable) shall be decreased by the amount of capacity that clears.

III.13.5. Bilateral Contracts in the Forward Capacity Market.

Market Participants shall be permitted to enter into Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals and Capacity Performance Bilaterals in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. Capacity Supply Obligation Bilaterals.

Capacity Supply Obligation Bilaterals are available for monthly periods. The qualification of resources subject to a Capacity Supply Obligation Bilateral is determined in the same manner as the qualification of resources is determined for reconfiguration auctions as specified in Section III.13.4.2.

A resource having a Capacity Supply Obligation seeking to shed that obligation (Capacity Transferring Resource) may enter into a bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part (Capacity Supply Obligation Bilateral), to a resource, or portion thereof, having Qualified Capacity for that Capacity Commitment Period that is not already obligated (Capacity Acquiring Resource), subject to the following limitations.

(a) A Capacity Supply Obligation Bilateral must be coterminous with a calendar month.

(b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the monthly Capacity Supply Obligation of the Capacity Transferring Resource. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the amount of unobligated Qualified Capacity (that is, Qualified Capacity as determined in the most recent Forward Capacity Auction or reconfiguration auction qualification process that is not subject to a Capacity Supply Obligation) of the Capacity Acquiring Resource during the month covered by the Capacity Supply Obligation Bilateral, as determined in the qualification process for the most recent Forward Capacity Auction or annual reconfiguration auction prior to the submission of the Capacity Supply Obligation Bilateral to the ISO.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource’s unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.

(d) [Reserved.]

(e) [Reserved.]

(f) [Reserved.]

(g) [Reserved.]

(h) A resource, or a portion thereof, that has been designated as a Self-Supplied FCA Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied FCA Resource as a result of the transaction.

(i) A monthly Capacity Supply Obligation may not be acquired by any resource on an approved outage for the relevant Obligation Month.

(j) A resource that is not expected to achieve FCM Commercial Operation prior to the end of a given Obligation Month in accordance with posted schedules may not submit a transaction as a Capacity Acquiring Resource for that month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a Capacity Supply Obligation Bilateral in an amount up to the absolute value of its Capacity Supply Obligation.

III.13.5.1.1. Process for Approval of Capacity Supply Obligation Bilaterals.

III.13.5.1.1.1. Timing of Submission and Prior Notification to the ISO.
The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Capacity Supply Obligation Bilaterals as soon as practicable after the issuance of Forward Capacity Auction results. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO no later than the end of the relevant submittal window.

III.13.5.1.1.2. Application.

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, in $/kW-month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of $0.00/kW-month.

III.13.5.1.1.3. ISO Review.

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral, and shall reject the Capacity Supply Obligation Bilateral if any of the provisions of this Section III.13.5.1 are not met. For a Capacity Supply Obligation Bilateral submitted before the relevant submittal window opens, this review shall occur once the submittal window opens. For a Capacity Supply Obligation Bilateral submitted after the submittal window opens, this review shall occur upon submission.

(b) After the close of the relevant submittal window, each Capacity Supply Obligation Bilateral shall be subject to a reliability review by the ISO to determine whether the transaction would result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules, during the Capacity Commitment Period associated with the transaction. Capacity Supply Obligation Bilaterals shall be reviewed by the ISO to ensure the regional and local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's review will consider the location and operating and rating limitations of resources associated with the Capacity Supply Obligation Bilateral to ensure reliability standards will remain satisfied if the capacity associated with the Capacity Transferring Resource is withdrawn and the capacity associated with the Capacity Acquiring Resource is accepted. The ISO's reliability reviews will assess transactions based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved Generator Asset or Demand Response Resource outage information, and will include transmission security studies. The ISO will review all confirmed Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. The ISO shall obtain and consider information from the Local Control Center regarding whether the Capacity Supply Obligation of the Capacity Transferring Resource is needed for local system conditions and whether it is adequately replaced by the Acquiring Resource.

The ISO will approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. If multiple Capacity Supply Obligation Bilaterals are submitted between the same resources, they may be reviewed together as one transaction and the most recent confirmation time among the related transactions will be used to determine the review order of the grouped transaction. Transactions that cannot meet the applicable reliability needs will only be accepted or rejected in their entirety and the resources will not be accepted or rejected in part for purposes of that transaction. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected for reliability reasons the Lead Market Participant or Project Sponsor, as appropriate, for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the reliability need prompting such rejection.

(c) Each Capacity Supply Obligation Bilateral shall be subject to a financial assurance review by the ISO. If the Capacity Transferring Resource and the Capacity Acquiring Resource are not both in compliance with all applicable provisions of the ISO New England Financial Assurance Policy, including those regarding Capacity Supply Obligation Bilaterals, the ISO shall reject the Capacity Supply Obligation Bilateral.

III.13.5.1.1.4. Approval.

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply Obligation of the Capacity Acquiring Resource shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

III.13.5.2. Capacity Load Obligations Bilaterals.

A Market Participant having a Capacity Load Obligation seeking to shed that obligation (“Capacity Load Obligation Transferring Participant”) may enter into a bilateral transaction to transfer all or a portion of its Capacity Load Obligation in a Capacity Zone (“Capacity Load Obligation Bilateral”) to any Market Participant seeking to acquire a Capacity Load Obligation (“Capacity Load Obligation Acquiring Participant”). A Capacity Load Obligation Bilateral must be in whole calendar month increments, may not exceed one year in duration, and must begin and end within the same Capacity Commitment Period. A Capacity Load Obligation Transferring Participant will be permitted to transfer, and a Capacity Load Obligation Acquiring Participant will be permitted to acquire, a Capacity Load Obligation if after entering into a Capacity Load Obligation Bilateral and submitting related information to the ISO within the specified submittal time period, the ISO approves such Capacity Load Obligation Bilateral.

III.13.5.2.1. Process for Approval of Capacity Load Obligation Bilaterals.

III.13.5.2.1.1. Timing.

Either the Capacity Load Obligation Transferring Participant or the Capacity Load Obligation Acquiring Participant may submit a Capacity Load Obligation Bilateral to the ISO. All Capacity Load Obligation Bilaterals must be submitted to the ISO in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the first month of the term of the Capacity Load Obligation Bilateral, a Capacity Load Obligation Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month (though a Capacity Load Obligation Bilateral submitted at that time may be revised by the parties to the transaction throughout the resettlement process). A Capacity Load Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Load Obligation Bilateral to the ISO no later than the same deadline that applies to submission of the Capacity Load Obligation Bilateral.

III.13.5.2.1.2. Application.

The submission of a Capacity Load Obligation Bilateral to the ISO shall include the following : (i) the amount of the Capacity Load Obligation being transferred in MW amounts up to three decimal places; (ii) the term of the transaction; (iii) identification of the Capacity Load Obligation Transferring Participant and the Capacity Load Obligation Acquiring Participant; and (iv) the Capacity Zone in which the Capacity Load Obligation is being transferred is located.

III.13.5.2.1.3. ISO Review.

The ISO shall review the information provided in support of the Capacity Load Obligation Bilateral and shall reject the Capacity Load Obligation Bilateral if any of the provisions of this Section II.13.5.2 are not met.

III.13.5.2.1.4. Approval.

Upon approval of a Capacity Load Obligation Bilateral, the Capacity Load Obligation of the Capacity Load Obligation Transferring Participant in the Capacity Zone specified in the submission to the ISO shall be reduced by the amount set forth in the Capacity Load Obligation Bilateral and the Capacity Load Obligation of the Capacity Load Obligation Acquiring Participant in the specified Capacity Zone shall be increased by the amount set forth in the Capacity Load Obligation Bilateral.

III.13.5.3. Capacity Performance Bilaterals.

A resource's Capacity Performance Score during a Capacity Scarcity Condition may be adjusted by entering into a Capacity Performance Bilateral as described in this Section III.13.5.3.

III.13.5.3.1. Eligibility.

If a resource has a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five-minute interval so long as both resources were subject to the same Capacity Scarcity Condition.

III.13.5.3.2. Submission of Capacity Performance Bilaterals.

The Lead Market Participant for a resource having a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition may submit a Capacity Performance Bilateral to the ISO assigning all or a portion of its Capacity Performance Score for that interval to another resource, subject to the eligibility requirements specified in Section III.13.5.3.1. The Capacity Performance Bilateral must be confirmed by the Lead Market Participant for the resource receiving the Capacity Performance Score.

III.13.5.3.2.1. Timing.

A Capacity Performance Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the month associated with the Capacity Performance Bilateral, a Capacity Performance Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Capacity Performance Bilateral may be revised by the parties to the transaction throughout the resettlement process).

III.13.5.3.2.2. Application.

The submission of a Capacity Performance Bilateral to the ISO shall include the following: (i) the resource identification number for the resource transferring its Capacity Performance Score; (ii) the resource identification number for the resource receiving the Capacity Performance Score; (iii) the MW amount of Capacity Performance Score being transferred; (iv) the specific five-minute interval or intervals for which the Capacity Performance Bilateral applies.

III.13.5.3.2.3. ISO Review.

The ISO shall review the information provided in submission of the Capacity Performance Bilateral, and shall reject the Capacity Performance Bilateral if any of the provisions of this Section III.13.5.3 are not met.

III.13.5.3.3. Effect of Capacity Performance Bilateral.

A Capacity Performance Bilateral does not affect in any way either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Capacity Performance Bilateral is to modify the Capacity Performance Scores of the transferring and receiving resources for the Capacity Scarcity Conditions subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments as described in Section III.13.7.2.

III.13.5.4 Annual Reconfiguration Transactions.

Annual Reconfiguration Transactions are available for annual reconfiguration auctions for Capacity Commitment Periods beginning on or after June 1, 2020, except that Annual Reconfiguration Transactions are not available for the first annual reconfiguration auction for the Capacity Commitment Period beginning on June 1, 2020.

III.13.5.4.1 Timing of Submission.

The Lead Market Participant or Project Sponsor for either a Capacity Transferring Resource or a Capacity Acquiring Resource may submit an Annual Reconfiguration Transaction to the ISO in accordance with posted schedules. The ISO will issue a schedule of the submittal windows for Annual Reconfiguration Transactions as soon as practicable after the issuance of Forward Capacity Auction results. An Annual Reconfiguration Transaction must be confirmed by the party other than the party submitting the Annual Reconfiguration Transaction to the ISO no later than the end of the relevant submittal window.

III.13.5.4.2 Components of an Annual Reconfiguration Transaction.

The submission of an Annual Reconfiguration Transaction must include the following:

1. the resource identification number of the Capacity Transferring Resource;
2. the applicable Capacity Commitment Period;

(3) the resource identification number of the Capacity Acquiring Resource, and;

3. a price ($/kW-month), quantity (MW) and Capacity Zone, to be used in settling the Annual Reconfiguration Transaction.

The maximum quantity of an Annual Reconfiguration Transaction is the higher of:

(1) the Capacity Transferring Resource’s maximum demand bid quantity determined pursuant to Section III.13.4.2.2(b), less the quantity of any previously confirmed Annual Reconfiguration Transactions, and;

(2) the Capacity Acquiring Resource’s maximum supply offer quantity determined pursuant to Section III.13.4.2.1.1, less the quantity of any previously confirmed Annual Reconfiguration Transactions.

An Annual Reconfiguration Transaction may not be submitted unless the maximum demand bid quantity and maximum supply offer quantity are each greater than zero.

Each Annual Reconfiguration Transaction is limited to a single Capacity Acquiring Resource and a single Capacity Transferring Resource.

If any demand bid of a Capacity Transferring Resource or supply offer of a Capacity Acquiring Resource that is associated with an Annual Reconfiguration Transaction is rejected for reliability reasons pursuant to Section III.13.2.2(c) or Section III.13.4.2.1.5, respectively, the Annual Reconfiguration Transaction is cancelled.

III.13.5.4.3 Settlement of Annual Reconfiguration Transactions.

Annual Reconfiguration Transactions are settled on a monthly basis during the applicable Capacity Commitment Period. The monthly payment amount is equal to the transaction quantity multiplied by the difference between the annual reconfiguration auction clearing price and the transaction price. If the payment amount is positive, payment is made to the Lead Market Participant with the Capacity Transferring Resource and charged to the Lead Market Participant with the Capacity Acquiring Resource. If the payment amount is negative, payment is made to the Lead Market Participant with the Capacity Acquiring Resource and charged to the Lead Market Participant with the Capacity Transferring Resource.

III.13.6. Rights and Obligations.

Resources assuming a Capacity Supply Obligation through a Forward Capacity Auction or resources assuming or shedding a Capacity Supply Obligation through a reconfiguration auction or a Capacity Supply Obligation Bilateral shall comply with this Section III.13.6 for each Capacity Commitment Period. In the event a resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or Capacity Supply Obligation Bilateral can not be allowed to shed its Capacity Supply Obligation due to system reliability considerations, the resource shall maintain the Capacity Supply Obligation until the resource can be released from its Capacity Supply Obligation. No additional compensation shall be provided through the Forward Capacity Market if the resource fails to be released from its Capacity Supply Obligation.

III.13.6.1. Resources with Capacity Supply Obligations.

A resource with a Capacity Supply Obligation assumed through a Forward Capacity Auction, reconfiguration auction, or a Capacity Supply Obligation Bilateral shall comply with the requirements of this Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, in which the Capacity Supply Obligation applies.

III.13.6.1.1. Generating Capacity Resources with Capacity Supply Obligations.

III.13.6.1.1.1. Energy Market Offer Requirements.

(a) A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:

(i) the sum of the Generating Capacity Resource's Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours; or

(ii) if the Generating Capacity Resource cannot meet the offer requirements in Section III.13.6.1.1.1(a)(i) due to physical design limits, then the resource shall be offered into the Day-Ahead Energy Market at a MW amount equal to or greater than its Economic Minimum Limit at a price of zero or shall be self-scheduled in the Day-Ahead Energy Market at a MW amount equal to or greater than the resource's Economic Minimum Limit.

(b) Notwithstanding the foregoing, if the Generating Capacity Resource is a Settlement Only Resource, it may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.1.2. Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the known capability of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.19.

III.13.6.1.1.3. [Reserved.]

III.13.6.1.1.4. [Reserved.]

III.13.6.1.1.5. Additional Requirements for Generating Capacity Resources.

Generating Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1 and the requirement to provide to the ISO, upon request and as soon as practicable, confirmation of gas volume schedules sufficient to deliver the energy scheduled for each Generating Capacity Resource using natural gas;

(c) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures (except that Settlement Only Resources are not subject to outage requirements), provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.1.2. Import Capacity Resources with Capacity Supply Obligations.

III.13.6.1.2.1. Energy Market Offer Requirements.

A Market Participant with an Import Capacity Resource must offer one or more External Transactions to import energy in the Day-Ahead Energy Market and Real-Time Energy Market for every hour of each Operating Day at the same external interface that, in total, equal the resource's Capacity Supply Obligation, except that:

(i) the offer requirement does not apply to any hour in which any External Resource associated with an Import Capacity Resource is on an outage;

(ii) the Day-Ahead Energy Market offer requirement does not apply to any hour in which the import transfer capability of the external interface is 0 MW, and;

(iii) the Real-Time Energy Market offer requirement does not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which Coordinated Transaction Scheduling is implemented.

Each External Transaction submitted in the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

Each External Transaction submitted in the Real-Time Energy Market in accordance with Section III.1.10.7 must reference the associated Import Capacity Resource.

In all cases an Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource.

III.13.6.1.2.2. Additional Requirements for Import Capacity Resources.

A Market Participant with an Import Capacity Resource that is associated with an External Resource must:

(i) comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the External Resource's native Control Area, and;

(ii) notify the ISO of all outages impacting the Capacity Supply Obligation of the Import Capacity Resource in accordance with the outage notification requirements in ISO New England Operating Procedure No. 5.

III.13.6.1.3. Intermittent Power Resources with Capacity Supply Obligations.

III.13.6.1.3.1. Energy Market Offer Requirements.

(a) Market Participants with Intermittent Power Resources that are Dispatchable Resources and have a Capacity Supply Obligation are required to submit offers in the Day-Ahead Energy Market consistent with the Market Participant's expectation of the output of the resource in Real-Time. Market Participants with non-dispatchable Intermittent Power Resources with a Capacity Supply Obligation may submit, but are not required to submit, offers into the Day-Ahead Energy Market. Market Participants are required to submit offers for Intermittent Power Resources with a Capacity Supply Obligation for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day-Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

(b) Notwithstanding the foregoing, an Intermittent Power Resource that is a Settlement Only Resource may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.3.2. [Reserved.]

III.13.6.1.3.3. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals;

(b) Operating Data collection requirements as detailed in the ISO New England Manuals;

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals (except that Intermittent Power Resources that are Settlement Only Resources need not comply with outage requirements).

III.13.6.1.4. [Reserved.]

III.13.6.1.5. Demand Capacity Resources with Capacity Supply Obligations.

III.13.6.1.5.1. Energy Market Offer Requirements.

(a) A Market Participant with an Active Demand Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers for its Demand Response Resources into the Day-Ahead Energy Market and Real-Time Energy Market in at least the MW amount described in this Section III.13.6.1.5.1; for purposes of the following comparisons, the portion of Demand Reduction Offers not associated with Net Supply shall be increased by average avoided peak transmission and distribution losses. The sum of the Demand Reduction Offers must be equal to or greater than the Active Demand Capacity Resource's Capacity Supply Obligation whenever the Demand Response Resources are physically available. If the Demand Response Resources are physically available at a level less than the Active Demand Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers will equal that level and shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each Demand Reduction Offer from a Demand Response Resource made into the Day-Ahead Energy Market shall also meet the following requirement:

> (i) the sum of the Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time plus Minimum Reduction Time plus Minimum Time Between Reductions is less than or equal to 72 hours.

(b) Seasonal Peak Demand Resources and On-Peak Demand Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.5.2. Requirement that Offers Reflect Accurate Demand Response Resource Operating Characteristics.

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a Demand Response Resource associated with an Active Demand Capacity Resource must reflect the then-known operating characteristics of the resource. Consistent with Section III.1.10.9(d), Demand Response Resources must re-declare to the ISO any changes to offer parameters that occur in real time to reflect the operating characteristics of the resource. A resource failing to comply with this requirement shall be subject to potential referral under Section III.A.

III.13.6.1.5.3. Additional Requirements for Demand Capacity Resources.

(a) A Market Participant may not associate an Asset with a non-commercial Demand Capacity Resource during a Capacity Commitment Period if the Asset can be associated with a commercial Demand Capacity Resource whose capability is less than its Capacity Supply Obligation during that Capacity Commitment Period.

(b) An Energy Efficiency measure may be added to an On-Peak Demand Resource or Seasonal Peak Demand Resource (other than one consisting of Load Management or Distributed Generation) until two years after the start of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation; provided, however, that a resource that qualified for a Forward Capacity Auction associated with a Capacity Commitment Period beginning on or before June 1, 2024 may install Energy Efficiency measures until May 31, 2027. Once an Energy Efficiency measure has been associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource, the measure may not be transferred to a different resource.

(c) For purposes of confirming FCM Commercial Operation as described in Section III.13.3.8, the ISO shall use a summer Seasonal DR Audit value or summer Passive DR Audit value to verify the capacity rating of a Demand Capacity Resource with summer Qualified Capacity. A winter Seasonal DR Audit value or winter Passive DR Audit value may only be used to verify the winter commercial capacity of a Demand Capacity Resource. The summer and winter commercial capacity of a Demand Capacity Resource consisting of Energy Efficiency measures may be verified in any month of the year.

(d) For Active Demand Capacity Resources, a summer Seasonal DR Audit value shall be established for use from April 1 through November 30 and a winter Seasonal DR Audit value shall be established for use from December 1 through March 31. The summer or winter Seasonal DR Audit value of an Active Demand Capacity Resource is equal to the sum of the like-season Seasonal DR Audit values of its constituent Demand Response Resources as determined pursuant to Section III.1.5.1.3.1. The Seasonal DR Audit value of an Active Demand Capacity Resource shall automatically update whenever a new

Seasonal DR Audit value is approved for a constituent Demand Response Resource or with changes to the makeup of the constituent Demand Response Resources.

(e) On-Peak Demand Resources and Seasonal Peak Demand Resources shall in addition: (i) comply with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals; and (ii) comply with the auditing and rating requirements as detailed in Sections III.13.6.1.5.4 and III.13.6.1.5.5 and the ISO New England Manuals.

(f) Active Demand Capacity Resources shall in addition: (i) comply with the measurement and verification requirements and the Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1, and with outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures; and (ii) comply with the auditing and rating requirements as detailed in Section III.13.6.1.5.5 and the ISO New England Manuals.

III.13.6.1.5.4. On-Peak Demand Resource and Seasonal Peak Demand Resource Auditing Requirements.

(a) A summer Passive DR Audit value and a winter Passive DR Audit value must be established for each On-Peak Demand Resource and Seasonal Peak Demand Resource in every Capacity Commitment Period during which the On-Peak Demand Resource or Seasonal Peak Demand Resource has an annual or monthly Capacity Supply Obligation.

(b) Summer Passive DR Audit values shall be determined based on data for one or more months of the summer Passive DR Auditing Period (June through August). Winter Passive DR Audit values shall be determined based on data for one or more months of the winter Passive DR Auditing Period (December through January).

(c) Passive DR Audit values will be made available to the Market Participant within 20 Business Days following the end of the period for which the audit value is determined by the ISO.

(d) The audit value of an On-Peak Demand Resource is determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the On-Peak Demand Resource during the Demand Resource On-Peak Hours.

(e) The audit value of a Seasonal Peak Demand Resource is determined by evaluating the Average Hourly Output or Average Hourly Load Reduction of each Asset associated with the Seasonal Peak Demand Resource during the Demand Resource Seasonal Peak Hours. If there are no Demand Resource Seasonal Peak Hours in a month during the Passive DR Auditing Period, performance during Demand Resource On-Peak Hours in that month may be used.

(f) Passive DR Audit values shall become effective one calendar day after being made available to the Market Participant and remain valid until the earlier of: (i) the next like-season Passive DR Audit value becomes effective or (ii) the end of the following Capability Demonstration Year.

(g) For On-Peak Demand Resources consisting of Energy Efficiency measures and Seasonal Peak Demand Resources consisting of Energy Efficiency measures, the ISO will calculate a summer Passive DR Audit value and a winter Passive DR Audit value in each month of the year. For all other On-Peak Demand Resources and Seasonal Peak Demand Resources, a Market Participant may request that a summer or winter Passive DR Audit value be determined based on data for, respectively, a summer or winter month outside of the Passive DR Auditing Periods. (For Demand Capacity Resources, summer months are April through November; all other months are winter months.) Such an audit shall not satisfy the Passive DR Audit requirement.

III.13.6.1.5.5. Additional Demand Capacity Resource Audits.

The ISO may perform additional audits for a Demand Capacity Resource to establish or verify the capability of the Demand Capacity Resource and its underlying assets and measures. This additional auditing may consist of two levels.

(a) Level 1 Audit: the ISO will establish the audit results by conducting a review of records of the Assets and measures to verify that the reported Assets and measures have been installed and are operational. The audit shall include, but is not limited to, reviewing project or program databases, invoices, installation reports, work orders, and field inspection reports. In addition, the audit may involve reviewing any independent inspections or evaluations conducted as part of program implementation and program evaluation.

(b) Level 2 Audit: the ISO will establish the audit results by initiating or conducting an on-site field audit to verify the installation and performance of the Assets and measures. Such an audit may include a random or select sample of facilities and measures.

A level 1 audit is not required to precede a level 2 audit. If the results of the audit indicate that the demand reduction capability of the Demand Capacity Resource is less than or greater than its most recent like-season Passive DR Audit value or Seasonal DR Audit value, then the Demand Capacity Resource's audit value shall be adjusted accordingly.

III.13.6.1.6. DNE Dispatchable Generator.

III.13.6.1.6.1. Energy Market Offer Requirements.

Beginning on June 1, 2019, Market Participants with DNE Dispatchable Generators with a Capacity Supply Obligation must submit offers into the Day-Ahead Energy Market for the full amount of the resource's expected hourly physical capability as determined by the Market Participant. Market Participants with DNE Dispatchable Generators having a Capacity Supply Obligation must submit offers for the Real-Time Energy Market consistent with the characteristics of the resource. For purposes of calculating Real-Time NCPC Charges, DNE Dispatchable Generators shall have a generation deviation of zero.

III.13.6.2. Resources without a Capacity Supply Obligation.

A resource that does not have any Capacity Supply Obligation shall comply with the requirements in this Section III.13.6.2, and shall not be subject to the requirements set forth in Section III.13.6.1 during the Capacity Commitment Period, or portion thereof, for which the resource has no Capacity Supply Obligation.

III.13.6.2.1. Generating Capacity Resources without a Capacity Supply Obligation.

III.13.6.2.1.1. Energy Market Offer Requirements.

A Generating Capacity Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. A Generating Capacity Resource that is a Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.1.1.1. Day-Ahead Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Day-Ahead Energy Market. If any portion of the offered energy clears in the Day-Ahead Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the operating day, including the obligation to follow ISO Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.1.1.2. Real-Time Energy Market Participation.

A Generating Capacity Resource having no Capacity Supply Obligation may submit an offer into the Real-Time Energy Market. If any portion of the offered energy clears in the Real-Time Energy Market, the entire Supply Offer, up to the Economic Maximum Limit offered into the Real-Time Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow ISO Dispatch Instructions. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.1.2. Additional Requirements for Generating Capacity Resources Having No Capacity Supply Obligation.

Generating Capacity Resources having no Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with the auditing and rating requirements as detailed in the ISO New England Manuals;

(b) complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Generating Capacity Resources having no Capacity Supply Obligation are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.2.2. [Reserved.]

III.13.6.2.3. Intermittent Power Resources without a Capacity Supply Obligation.

III.13.6.2.3.1. Energy Market Offer Requirements.

An Intermittent Power Resource having no Capacity Supply Obligation is not required to offer into the Day-Ahead Energy Market or Real-Time Energy Market. An Intermittent Power Resource that is a Settlement Only Resource may not offer into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.3.2. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources are subject to the following additional requirements:

(a) auditing and rating requirements as detailed in the ISO New England Manuals; and

(b) Operating Data collection requirements as detailed in the ISO New England Manuals.

III.13.6.2.4. [Reserved.]

III.13.6.2.5. Demand Capacity Resources without a Capacity Supply Obligation.

III.13.6.2.5.1. Energy Market Offer Requirements.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation is not required to offer Demand Reduction Offers for the Demand Response Resource into the Day-Ahead Energy Market or Real-Time Energy Market.

Seasonal Peak Demand Resources and On-Peak Demand Resources may not submit Demand Reduction Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.2.5.1.1. Day-Ahead Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation may submit a Demand Reduction Offer into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer, up to the Maximum Reduction offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the

Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.1.2. Real-Time Energy Market Participation.

A Market Participant with a Demand Response Resource associated with an Active Demand Capacity Resource without a Capacity Supply Obligation, that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit a Demand Reduction Offer in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.2. Additional Requirements for Demand Capacity Resources Having No Capacity Supply Obligation.

Demand Capacity Resources without a Capacity Supply Obligation are subject to the following additional requirements:

(a) complying with Section III.13.6.1.5.3(a) and (b) and with the auditing and rating requirements described in Section III.13.6.1.5.5 and the ISO New England Manuals; and

(b) for Active Demand Capacity Resources, complying with the Operating Data collection requirements detailed in the ISO New England Manuals; and

(c) for Active Demand Capacity Resources, complying with outage requirements as outlined in the ISO New England Operating Procedures and ISO New England Manuals. Active Demand Capacity Resources having no Capacity Supply Obligation are not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.3. Exporting Resources.

A resource that is exporting capacity not subject to a Capacity Supply Obligation to an external Control Area shall comply with this Section III.13.6.3 and the ISO New England Manuals. Intermittent Power Resources and Demand Capacity Resources are not permitted to back a capacity export to an external Control Area. The portion of a resource without a Capacity Supply Obligation that will be used in Real-Time to support an External Transaction sale must comply with the energy market offer requirements of Section III.1.10.7.

III.13.6.4. ISO Requests for Energy.

The ISO may request that an Active Demand Capacity Resource or a Generating Capacity Resource having capacity that is not subject to a Capacity Supply Obligation provide energy for reliability purposes in the Real-Time Energy Market, but such resource shall not be obligated under Section III.13 of this Tariff by such a request to provide energy from that capacity. If such resource does provide energy from that capacity, the resource shall be paid based on its most recent offer and is eligible for NCPC.

III.13.6.4.1. Real-Time High Operating Limit.

For purposes of facilitating ISO requests for energy under Section III.13.6.4, a Market Participant must report an up-to-date Real-Time High Operating Limit value at all times for a Generating Capacity Resource.

III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1, as adjusted to account for peak energy rents as described in Section III.13.7.1.2.

III.13.7.1.1. Monthly Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period based on the following amounts:

(a) **Forward Capacity Auction**. For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

(d) **Substitution Auctions.** For a resource whose offer or bid has cleared in a substitution auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the substitution auction clearing price. Notwithstanding the foregoing, the monthly capacity charge for a demand bid cleared at a substitution auction clearing price above its bid price shall be calculated using its bid price.

III.13.7.1.2 Peak Energy Rents.

For Capacity Commitment Periods beginning prior to June 1, 2019, Capacity Base Payments to resources with Capacity Supply Obligations, except for (1) On-Peak Demand Resources, (2) Seasonal Peak Demand Resources, and (3) New Generating Capacity Resources that have cleared in the Forward Capacity Auction and have completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service are not able to achieve FCM Commercial Operation, shall be decreased by Peak Energy Rents ("PER") calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone. Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied.

III.13.7.1.2.1 Hourly PER Calculations.

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with one of the following formulas, which include scaling adjustments for system load and availability:

For hours within the period beginning September 30, 2016 through May 31, 2018:

Hourly PER($/kW) = [(LMP - Adjusted Hourly PER Strike Price) * [Scaling Factor] * [Availability Factor]
Where:

Adjusted Hourly PER Strike Price = Strike Price + Hourly PER Adjustment

Hourly PER Adjustment = average of Five-Minute PER Strike Price Adjustment values

Five-Minute PER Strike Price Adjustment = MAX (Thirty-Minute Operating Reserve clearing price - $500/MWh, 0)+ MAX (Ten-Minute Non-Spinning Reserve clearing price – Thirty-Minute Operating Reserve clearing price - $850/MWh, 0).

Strike Price = as defined below

Scaling Factor = as defined below

Availability Factor = as defined below

For all other hours:

Hourly PER($/kW) = [LMP - Strike Price] * [Scaling Factor] * [Availability Factor]
Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Capacity Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95.

(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of the following, as determined on a daily basis: ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation; or day-ahead gas measured at the AGT-CG (Non-G) hub;

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.1.2.2. Monthly PER Application.

The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as the Average Monthly PER multiplied by the resource's Capacity Supply Obligation for the Obligation Month (less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource); provided, however, that in no case shall a resource's PER deduction for an Obligation Month be less than zero or greater than the product of the resource's Capacity Supply Obligation and the relevant Forward Capacity Auction Capacity Clearing Price.

III.13.7.1.3. Export Capacity.

If there are any Export Bids or Administrative Export De-List Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

> Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-List Bid]
>
> Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located= [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-list Bid]
>
> Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.5.2.

III.13.7.1.4. [Reserved.]

III.13.7.2 Capacity Performance Payments.

III.13.7.2.1 Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.13.7.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource or Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.13.7.2.2(c), for any On-Peak Demand Resource or Seasonal Peak Demand Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.13.7.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(i) A Demand Response Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource's Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource's Actual Capacity Provided shall not be less than zero.

(ii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero) (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval, excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

> (i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.
>
> (ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in

Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval (with the Actual Capacity Provided of Energy Efficiency measures being zero, as specified in Section III.13.7.2.2(c)(i)) minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, the Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025, the Capacity Performance Payment Rate shall be $5455/MWh. For the Capacity Commitment Period beginning on June 1, 2025 and ending on May 31, 2026, the Capacity Performance Payment Rate shall be $9337/MWh. For the Capacity Commitment Period beginning on June 1, 2026 and ending on May 31, 2027 and thereafter, the Capacity Performance Payment Rate shall be $10833/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.13.7.2.6 Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

III.13.7.3.1 Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month).

III.13.7.3.2 Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (FCAcp – FCAsp) – (12 months x FCAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCAcp = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.13.7.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments.
For each type of Capacity Scarcity Condition as described in Section III.13.7.2.1 and for each Capacity Zone, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a) and (b) below. Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.

(a) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month and excluding any resource, or portion thereof, consisting of Energy Efficiency measures. If the charge described in this Section III.13.7.4(a) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(a).

(b) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources (excluding any resource, or portion thereof, consisting of Energy Efficiency measures) in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.13.7.4(b)

III.13.7.5. Charges to Market Participants with Capacity Load Obligations.

III.13.7.5.1. Calculation of Capacity Charges Prior to June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning prior to June 1, 2022. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), less PER adjustments for resources in the zone as defined in Section III.13.7.1.2, and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month may also receive a failure to cover credit equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone, and; (b) the sum of all failure to cover charges in the Capacity Zone calculated pursuant to Section III.13.3.4(b), divided by total Capacity Load Obligation in the Capacity Zone.

III.13.7.5.1.1. Calculation of Capacity Charges On and After June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning on or after June 1, 2022. For purposes of this Section III.13.7.5.1.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to the following charges and adjustments:

III.13.7.5.1.1.1 Forward Capacity Auction Charge.

The FCA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone FCA Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone FCA Costs, for each Capacity Zone, are the Total FCA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total FCA Costs are the sum of, for all Capacity Zones, (i) Capacity Supply Obligations in each zone (the total obligation awarded to or shed by resources in the Forward Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.13.7.5.1.1.6 and excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) multiplied by the applicable clearing price from the auction in which the obligation was awarded to (or shed by) the resource, and (ii) the difference between the bid price and the substitution auction clearing price that was not included in the capacity charge pursuant to the second sentence of Section III.13.7.1.1(d). Capacity Supply Obligations awarded to Proxy De-List Bids in the primary auction, or shed by demand bids entered into the substitution auction on behalf of a Proxy De-List Bid, are excluded from Total FCA Costs.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.2 Annual Reconfiguration Auction Charge.

The total annual reconfiguration auction charge, for each Capacity Zone and each associated annual reconfiguration auction, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone Annual Reconfiguration Auction Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone Annual Reconfiguration Auction Costs, for each Capacity Zone, are the Total Annual Reconfiguration Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total Annual Reconfiguration Auction Costs are the sum, for all Capacity Zones and each associated annual reconfiguration auction, of the product of the Capacity Supply Obligations acquired through the annual reconfiguration auction in each zone (adjusted for any obligations procured in the annual reconfiguration auction that are subsequently terminated pursuant to Section III.13.3.4A) and the zonal annual reconfiguration auction clearing price, minus the sum, for all Capacity Zones, of the product of the amount of any Capacity Supply Obligation shed through the annual reconfiguration auction in each zone and the applicable annual reconfiguration auction clearing price.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.3. Monthly Reconfiguration Auction Charge.

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price, minus the sum of, for all

Capacity Zones, any Capacity Supply Obligations shed through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.4. HQICC Capacity Charge.

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.5. Self-Supply Adjustment.

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where

Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.

Foregone capacity payments to Self-Supplied FCA Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections

IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone associated with the designated self-supply quantity.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.6. Intermittent Power Resource Capacity Adjustment.

The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.

Where

Intermittent Power Resource Seasonal Variance is the difference between the FCA payments for Intermittent Power Resource in the Obligation Month and the base FCA payments for Intermittent Power Resources.

FCA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to or shed by Intermittent Power Resources in the Forward Capacity Auction process for the Obligation Month pursuant to Section III.13.2.7.6 or Section III.13.2.8.1.1 (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base FCA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the FCA Qualified Capacity procured from or shed by Intermittent Power Resources in the Forward Capacity Auction process (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.7. Multi-Year Rate Election Adjustment.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity

Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

> Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.
>
> Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.
>
> Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

> Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the

year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period.

III.13.7.5.1.1.8 CTR Transmission Upgrade Charge.

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.13.7.5.4.4 (f), multiplied by the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

III.13.7.5.1.1.9 CTR Pool-Planned Unit Charge.

The CTR Pool-Planned Unit charge is: (a) the Capacity Load Obligation in the Capacity Zone less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5.

Where

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.13.7.5.4.5 (b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.10. Failure to Cover Charge Adjustment.

The failure to cover charge adjustment, for each Capacity Zone, is (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Failure to Cover Charges divided by Zonal Capacity Obligation.

Where:

Zonal Failure to Cover Charges are the product of: (1) the sum, for all Capacity Zones, of the failure to cover charges calculated pursuant to Section III.13.3.4(b), and; (2) the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price as determined pursuant to Section III.13.3.4.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation.
The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to Section III.13.2.3.4. The Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals for Capacity Commitment Periods beginning prior to June 1, 2022 and excluding any additional obligations awarded to Intermittent Power Resources pursuant to Section III.13.2.7.6 that exceed the FCA Qualified Capacity procured in the Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022) plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022) to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022).

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above and (ii) the ratio of the sum of the load serving entity's annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period to the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each month and Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource or Demand Response Resource.

III.13.7.5.2.1. Charges Associated with Dispatchable Asset Related Demands.

Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource.

The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.5.3. Excess Revenues.

(a) For Capacity Commitment Periods beginning prior to June 1, 2022, revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.5.3.

(b) Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section III.13.3.4A shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

III.13.7.5.4. Capacity Transfer Rights.

III.13.7.5.4.1. Definition and Payments to Holders of Capacity Transfer Rights.
This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

Capacity Transfer Rights are calculated for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone's Net Regional Clearing Price and absolute value of each Capacity Zone's Capacity Load Obligations, as calculated in Section III.13.7.5.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone, as adjusted for PER.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources.

III.13.7.5.4.2. Allocation of Capacity Transfer Rights.
This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.5.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface**. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface**. Except as provided in Section III.13.7.5.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

III.13.7.5.4.3. Allocations of CTRs Resulting From Revised Capacity Zones.
This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.5.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.5.4.4. Specifically Allocated CTRs Associated with Transmission Upgrades.

(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(e) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine export interface for as long as Casco Bay continues to pay to support the transmission upgrades.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface.

III.13.7.5.4.5. Specifically Allocated CTRs for Pool-Planned Units.

(a) In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive an initial allocation of CTRs equal to the most recent seasonal claimed capability of the ownership entitlements in such unit, adjusted for any designated self-supply quantities as described in Section III.13.1.6.2. Municipal utility entitlements are set as shown in the table below and are not transferrable.

	Millstone 3	Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4	Summer (MW)	Winter (MW)
Nominal Summer (MW)	1155.001	1244.275	104.000	100.000	104.000	67.400	65.300	586.725		
Nominal Winter (MW)	1155.481	1244.275	119.000	116.000	119.000	87.400	85.300	608.575		
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%	58.26	63.73
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%	5.04	5.55
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%	2.93	2.37
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%	15.49	15.64
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%	10.40	11.07
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%	57.69	60.26
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%	82.98	92.77
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%	30.53	32.64
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%	4.53	5.22
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%	4.71	5.35
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	7.63	7.63
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%	5.81	6.61
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%	26.40	30.36
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%	17.01	19.33
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%	15.34	16.63

Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%	24.05	24.12
Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%	10.70	12.28
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%	11.67	13.63
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%	36.93	42.17
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%	21.48	24.45
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%	25.58	29.49
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.33	1.33
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%	4.82	5.53
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%	24.33	26.23
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	10.89	10.90
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%	6.60	7.38
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.25	1.25
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%	10.67	12.27
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%	6.97	7.99
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%	10.18	11.69
Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%	67.51	77.27

This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant ("WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located, and; (ii) the MW quantity of the specifically allocated CTRs.

III.13.7.5.5. Forward Capacity Market Net Charge Amount.
The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charges; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund (for Capacity Commitment Periods beginning prior to June 1, 2022); and (d) any applicable export charges.

III.13.8. Reporting and Price Finality

III.13.8.1. Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto.

(a) For each Forward Capacity Auction, no later than 20 Business Days after the issuance of retirement determination notifications described in Section III.13.1.2.4(a), the ISO shall make a filing with the Commission pursuant to Section 205 of the Federal Power Act describing the Permanent De-List Bids and Retirement De-List Bids established pursuant to Section III.13.1.2.3.2, and the substitution auction test prices established pursuant to Section III.13.2.8.3.1A. The ISO will file the following information confidentially: the determinations made by the Internal Market Monitor with respect to each Permanent De-List Bid, Retirement De-List Bid, and substitution auction test price, and supporting documentation for each such determination. The confidential filing shall indicate those resources that will permanently de-list or retire prior to the Forward Capacity Auction and those Permanent De-List Bids and Retirement De-List Bids for which a Lead Market Participant has made an election pursuant to Section III.13.1.2.4.1.

(b) The Forward Capacity Auction shall be conducted using the determinations as approved by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

(c) For each Forward Capacity Auction, no later than 90 days prior to the first day of the auction, the ISO shall make an informational filing with the Commission detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination, provided, however, that the determinations in subsections (vi), (vii), (viii), and (ix) below shall be filed confidentially with the Commission in the informational filing, except determinations on which new resources have been rejected due to overlapping interconnection impacts (the determinations in subsections (vi), (vii), (viii), and (ix) shall be published by the ISO no later than 15 days after the Forward Capacity Auction, with the exception of bid price and offer price information and submitted Load-Side Relationship Certifications, which shall remain confidential):

(i) which Capacity Zones shall be modeled in the Forward Capacity Auction;

(ii) the transmission interface limits as determined pursuant to Section III.12.5;

(iii) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Forward Capacity Auction;

(iv) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Forward Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;

(v) for each resource that submitted a Load-Side Relationship Certification, the following information: the resource technology type; which qualifying circumstance in Section III.A.21.1.3 was asserted in the Load-Side Relationship Certification; the relevant state policy asserted in the Load-Side Relationship Certification, if any; whether the ISO accepted or rejected the Load-Side Relationship Certification; and, consequently, whether the resource was subject to a review for the exercise of buyer-side market power;

(vi) which new resources are accepted and rejected in the qualification process to participate in the Forward Capacity Auction;

(vii) which new resources were not reviewed for an exercise of buyer-side market power because of one of the conditions described in Sections III.A.21.1.1, III.A.21.1.2, or III.A.21.1.3; the condition met by each such resource; and, for new resources that submitted a Load-Side Relationship Certification, the Load-Side Relationship Certification submitted by the resource;

(viii) the Internal Market Monitor's determinations made as part of any buyer-side market power review conducted pursuant to Section III.A.21.2 and any New Resource Offer Floor Price determinations made pursuant to Section III.A.21.3 with regard to a new resource, and the basis for any such determinations; for the avoidance of doubt, any information employed by the Internal Market Monitor in making these determinations related to the potential impact of a New Capacity Resource's offer on Capacity Clearing Prices, including any such information filed by the ISO in response to a pleading filed with the Commission, shall be filed confidentially and shall not be released to any entity, including to the Project Sponsor whose offer is the subject of dispute;

(ix) the Internal Market Monitor's determinations regarding offers or Static De-List Bids, Export Bids, and Administrative De-List Bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the Internal Market Monitor-determined prices established for any Static De-List Bids, Export Bids, and Administrative De-List Bids as described in Section III.13.1.2.3.2 based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor. The filing shall identify to the extent possible the components of the bid which were accepted as justified, and shall also identify to the extent possible the components of the bid which were not justified and which resulted in the Internal Market Monitor establishing an Internal Market Monitor-determined price for the bid;

(x) which existing resources are qualified to participate in the Forward Capacity Auction (this information will include resource type, capacity zone, and qualified MW); and

(xi) aggregate MW from new resources qualified to participate in the Forward Capacity Auction and aggregate de-list bid amounts.

(d) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(c) or in the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4(b) and III.13.1.3.5.7 must be filed with the Commission no later than 15 days after the ISO's submission of the informational filing. If the Commission does not issue an order within 75 days after the ISO's submission of the informational filing that directs otherwise, the determinations contained in the informational filing shall be used in conducting the Forward Capacity Auction, and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c). If within 75 days after the ISO's submission of the informational filing, the Commission does issue an order modifying one or more of the ISO's determinations, then the Forward Capacity Auction shall be conducted no earlier than 15 days following that order using the determinations as modified by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

III.13.8.2. Filing of Forward Capacity Auction Results and Challenges Thereto.

(a) As soon as practicable after the Forward Capacity Auction is complete, the ISO shall file the results of that Forward Capacity Auction with the Commission pursuant to Section 205 of the Federal Power Act, including the final set of Capacity Zones resulting from the auction, the Capacity Clearing Price in each of those Capacity Zones (and the Capacity Clearing Price associated with certain imports pursuant to Section III.13.2.3.3(d), if applicable), the substitution auction clearing prices and the total amount of payments associated with any demand bids cleared at a substitution auction clearing price above their demand bid prices, and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. Upon completion of the fourth and future auctions, such list of resources that receive Capacity Supply Obligation shall also specify which resources cleared as Conditional Qualified New Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Facility, as defined in Schedule 22 or Schedule 25 of Section II of the Transmission, Markets and Services Tariff, that secured a Queue Position to participate as a New Generating Capacity Resource in the Forward Capacity Auction and each resource with lower queue priority that was selected in the Forward Capacity Auction subject to a Long Lead Time Facility with the higher queue priority. The filing shall also enumerate de-list bids rejected for reliability reasons pursuant to Section III.13.2.5.2.5, and the reasons for those rejections.

(b) The filing of Forward Capacity Auction results made pursuant to this Section III.13.8.2 shall also include documentation regarding the competitiveness of the Forward Capacity Auction, which may include a certification from the auctioneer and the ISO that: (i) all entities offering and bidding in the Forward Capacity Auction were properly qualified in accordance with the provisions of Section III.13.1; and (ii) the Forward Capacity Auction was conducted in accordance with the provisions of Section III.13.

(c) Any objection to the Forward Capacity Auction results must be filed with the Commission within 45 days after the ISO's filing of the Forward Capacity Auction results. The filing of a timely objection with the Commission will be the exclusive means of challenging the Forward Capacity Auction results.

(d) Any change to the Transmission, Markets and Services Tariff affecting the Forward Capacity Market or the Forward Capacity Auction that is filed after the results of a Forward Capacity Auction have been accepted or approved by the Commission shall not affect those Forward Capacity Auction results.

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this ***Appendix A.***

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this ***Appendix A*** shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this ***Appendix A***. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this ***Appendix A***.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this ***Appendix A***, the provisions of ***Appendix A*** shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III.A.17.3 are also part of the Participants Agreement and cannot be modified in either ***Appendix A*** or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this ***Appendix A*** are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this ***Appendix A***). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

(b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.

(c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the External Market Monitor shall perform the following functions:

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this ***Appendix A***, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(c) Conduct evaluations and prepare reports on its own initiative or at the request of others.

(d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this ***Appendix A,*** provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this ***Appendix A***.

(f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.

(g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this ***Appendix A***, as appropriate.

(h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the Internal Market Monitor shall perform the following functions:

(a) Maintain ***Appendix A*** and consider whether ***Appendix A*** requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.

(b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this ***Appendix A***.

(c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this ***Appendix A.***

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

(i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this ***Appendix A***.

(j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this ***Appendix A*** are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

(i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.

(ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.

(iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this ***Appendix A***.

(iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this ***Appendix A.***

(v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend ***Appendix A*** as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

(k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:

(i) Anti-competitive gaming of Resources;

(ii) Conduct and market outcomes that are inconsistent with competitive markets;

(iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;

(iv) Actions in one market that affect price in another market;

(v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this ***Appendix A***, interfere with efficient market operation, both short-run and long-run; and

(vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this ***Appendix A***. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this ***Appendix A.*** If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

(m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this ***Appendix A*** for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule l (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this ***Appendix A***. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this ***Appendix A***, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential referral under Section III.A.19.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

(a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this ***Appendix A***, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this ***Appendix A***.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant**.** In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section

III.A.3.4(d) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this ***Appendix A*** for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus $2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2

2 or more	6

III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

(a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,

(b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,

(c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or

(d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

(a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;

(b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

(a) all Supply Offer parameters shall be reviewed for economic withholding;

(b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;

(c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;

(b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

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III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

(a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;

(b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than $25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

(a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
(b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or $100/MWh, whichever is lower. Offer block prices below $25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or $100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or $25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or $25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

i. local first contingency;
ii. local second contingency;
iii. VAR or voltage;
iv. distribution (Special Constraint Resource Service);
v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

(a) If the Resource is starting from an offline state, the Start-Up Fee;

(b) The sum of the No Load Fees for the Commitment Period; and

(c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 “General Threshold Energy Mitigation” or III.A.5.5.2 “Constrained Area Energy Mitigation” is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:

   i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,

   ii. for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 “Constrained Area Energy Mitigation”), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 “Manual Dispatch Energy Mitigation” is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource’s Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 “General Threshold Commitment Mitigation”, III.A.5.5.5 “Constrained Area Commitment Mitigation”, or III.A.5.5.6 “Reliability Commitment Mitigation” is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 “Start-Up Fee and No-Load Fee Mitigation” is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

Market Participants are responsible for providing the Internal Market Monitor with all the information and data necessary for the Internal Market Monitor to calculate up-to-date Reference Levels for each of a Market Participant's Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

(a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.

(b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.

(c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, Interruption Costs and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of an offer according to the following hierarchy, under which the first method that can be calculated is used:

(a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;

(b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,

(c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

(a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.

(b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.

(c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.

(d) For any Operating Day for which, during the previous 90 days:

(i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;

(ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.

(e) When in any hour the incremental energy parameter of an offer, including adjusted offers pursuant to Section III.2.4, is greater than $1,000/MWh.

For the purposes of this subsection:

i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.

ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.

iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.

iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.

(e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.

(f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:

(i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,

(ii) No-Load Fee or its corresponding fuel blends,

(iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,

(iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and

(v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

(a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".

(b) Costs must be documented.

(c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible. All cost estimates, including opportunity cost estimates, must be quantified and analytically supported.

(d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.

(e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

i. Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and
ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy/Reduction:
(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

(a) emissions limits;
(b) water storage limits;
(c) other operating permits that limit production of energy; and
(d) reducing electricity consumption.

No-Load:
(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price) + no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up/Interruption:
(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. [Reserved.]

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor the Energy Market as outlined below:

(a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.

(b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

$(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$.

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

(i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.

(ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.

(iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

(a) [Reserved].

(b) Section III.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.

(c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

(d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.

(e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.

(f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this ***Appendix A***. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.

Article 5 of the form of Cost-of-Service Agreement in ***Appendix I*** to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Market Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Cost Recovery Request Following Capping.

If as a result of an offer being capped under Section III.1.9, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was capped, the Market Participant may, within 20 days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit an additional cost recovery request to the Internal Market Monitor.

A request under this Section III.A.15 may seek recovery of additional costs incurred for the duration of the period of time for which the Resource was operated at the cap.

III.A.15.1.1. Timing and Contents of Request.

Within 20 days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant requesting additional cost recovery under this Section III.A.15.1 shall submit to the Internal Market Monitor a request in writing detailing: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data, documentation and calculations for those costs; and (ii) an explanation of why the actual costs of operating the Resource exceeded the capped costs.

III.A.15.1.2. Review by Internal Market Monitor.

To evaluate a Market Participant's request, the Internal Market Monitor shall use the data, calculations and explanations provided by the Market Participant to verify the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, using the same standards and methodologies the Internal Market Monitor uses to evaluate requests to update Reference Levels under Section III.A.3 of Appendix A. To the extent the Market Participant's request warrants additional cost recovery, the Internal Market Monitor shall reflect that adjustment in the Resource's Reference Levels for the period covered by the request. The ISO shall then re-apply the cost verification and capping formulas in Section III.1.9 using the updated Reference Levels to re-calculate the adjustments to the Market Participant's offers required thereunder, and then shall calculate additional cost recovery using the adjusted offer values.

Within 20 days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the Market Participant's request, detailing (i) the extent to which it agrees with the request with supporting explanation, and (ii) a calculation of the additional cost recovery. Changes to credits and charges resulting from an additional cost recovery request shall be included in the Data Reconciliation Process.

III.A.15.1.3. Cost Allocation.

The ISO shall allocate charges to Market Participants for payment of any additional cost recovery granted under this Section III.A.15.1 in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.15.2. Section 205 Filing Right.

If either

(a) as a result of mitigation applied to a Resource under this ***Appendix A*** for all or part of one or more Operating Days, or

(b) in the absence of mitigation, as a result of a request under Section III.A.15.1 being denied in whole or in part,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was mitigated or the Section III.A.15.1 request was denied, the Market Participant may submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. For filings to address cost recovery under Section III.A.15.2(a), the filing must be made within sixty days of receipt of the first Invoice issued containing credits or charges for the applicable Operating Day. For filings to address cost recovery under Section III.A.15.2(b), the filing must be made within sixty days of receipt of the first Invoice issued that reflects the denied request for additional cost recovery under Section III.A.15.1.

A request under this Section III.A.15.2 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having a Section III.A.15.1 request denied, costs incurred for the duration of the period of time addressed in the Section III.A.15.1 request.

III.A.15.2.1. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource, as reflected in the original offer and to the extent not recovered under Section III.A.15.1, exceeded the costs as reflected in the capped offer; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.2.2. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the applicable Invoice, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15.2 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2.1 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15.2 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.2.

III.A.15.2.3. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in ***Appendix D*** to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.
- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this ***Appendix A***, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

(a) the opportunity costs associated with Demand Reduction Offers;
(b) the accuracy of Demand Response Baselines;
(c) the method used to achieve a demand reduction, and;
(d) the accuracy of metered demand reported to the ISO.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A.***

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this ***Appendix A***.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of ***Appendix A***. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

(i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.

(ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.

(iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.

(iv) Review and assessment of the effectiveness of ***Appendix A*** and the administration of ***Appendix A*** by the Internal Market Monitor for consistency and compliance with the terms of ***Appendix A.***

(v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

(a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;

(b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;

(c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,

(d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). With respect to state regulatory bodies and state attorneys general ("authorized state agencies"), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External

Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct, as amended from time to time and available on the ISO's website. Consistent with the ISO New England Inc. Code of Conduct, at a minimum each such monitoring unit and its employees: (a) must have no material affiliation with any Market Participant or Affiliate, (b) must have no material financial interest in any Market Participant or Affiliate with potential exceptions for mutual funds and non-directed investments, (c) must not engage in any market transactions other than the performance of their duties hereunder, (d) may not accept anything of value from a Market Participant in excess of a *de minimis* amount, and (e) must advise a supervisor in the event they seek employment with a Market Participant, and must disqualify themselves from participating in any matter that would have an effect on the financial interest of the Market Participant.

III.A.18.2. Additional Ethical Conduct Standards.

The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.

No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of ***Appendix A***, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or

External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information

- (1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);
- (2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;
- (3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;
- (4) The specific act(s) or conduct that allegedly constituted the Market Violation;
- (5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;
- (6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;
- (7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

(A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) A detailed narrative describing the perceived market design flaw(s);

(2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;

(3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;

(4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the

Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers from New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from certain New Capacity Resources in the Forward Capacity Auction as described in this Section III.A.21. The provisions of Sections III.A.21.1 and III.A.21.2 are not applicable to offers from New Import Capacity Resources that are subject to the pivotal supplier test in Section III.A.23.

III.A.21.1. Applicability of Buyer-Side Market Power Review.

The Internal Market Monitor will not conduct a buyer-side market power review of New Capacity Resources that meet the criteria described in this Section III.A.21.1.

III.A.21.1.1. Resources with Capacity Not Exceeding 5 MW.

A New Capacity Resource will not be subject to the Internal Market Monitor's buyer-side market power review if the project's expected auction capacity (in MW) at the time of the qualification process for the Forward Capacity Auction does not exceed 5 MW.

If a New Capacity Resource's expected auction capacity exceeds 5 MW at the time of the qualification process for the Forward Capacity Auction, but the final FCA Qualified Capacity for the New Capacity Resource does not exceed 5 MW, an offer from the New Capacity Resource will not be mitigated pursuant to Section III.A.21.2.3, notwithstanding any buyer-side market review that may have been conducted at the time of the qualification process.

III.A.21.1.2. Passive Demand Response Resources.

New Demand Capacity Resources that consist solely of On-Peak Demand Resources or Seasonal Peak Demand Resources will not be subject to the Internal Market Monitor's buyer-side market power review.

III.A.21.1.3. Resources Supported by a Qualifying Load-Side Relationship Certification.

New Capacity Resources will not be subject to the Internal Market Monitor's buyer-side market power review if the Project Sponsor submits a Load-Side Relationship Certification, as described in this Section III.A.21.1.3, demonstrating one of the following qualifying circumstances:

(a) the Project Sponsor and its Affiliates or partners, if any, are not load serving entities and are neither receiving nor expecting to receive any revenues from a load serving entity, state, or political subdivision of a state that relate to the development, operation, control, or output of the New Capacity Resource (excepting any revenues earned through an ISO-administered market); or

(b) the New Capacity Resource is a Sponsored Policy Resource.

For the purpose of this Section III.A.21, a load serving entity is any entity that has or is the type of entity that could acquire a Capacity Load Obligation in the Forward Capacity Market.

To demonstrate such circumstances, the Project Sponsor must include as part of the Load-Side Relationship Certification a sworn affidavit from an officer or principal for the Project Sponsor that includes factual detail sufficient to explain the qualifying circumstances. The Project Sponsor must submit the Load-Side Relationship Certification with the New Capacity Qualification Package, described in Section III.13.1.1.2.2, or the New Demand Capacity Resource Qualification Package, described in Section III.13.1.4.1.1.2. If the ISO is unable to determine from the Load-Side Relationship Certification that one of the qualifying circumstances exists, the New Capacity Resource's offer shall be subject to buyer-side market power review pursuant to Section III.A.21.2.

III.A.21.2. Review for the Exercise of Buyer-Side Market Power.

With the exception of New Capacity Resources that meet the criteria described in Section III.A.21.1, the Internal Market Monitor shall review requested lowest offer prices from New Capacity Resources, as described in Sections III.13.1.1.2.2.3(a) and III.13.1.4.1.1.2.8(a), for the potential exercise of buyer-side market power following the process described in this Section III.A.21.2.

III.A.21.2.1. Conduct Test.

The Internal Market Monitor will perform a conduct test by reviewing the information described in Sections III.13.1.1.2.2.3(a) and III.13.1.4.1.1.2.8(a) and determining a New Resource Offer Floor Price, as described in Section III.A.21.3, for the New Capacity Resource. A requested lowest offer price from a New Capacity Resource fails the conduct test if the Internal Market Monitor determines that the New Resource Offer Floor Price exceeds the requested lowest offer price.

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III.A.21.2.2. Demonstration of Lack of Incentive to Exercise Buyer-Side Market Power. If the Project Sponsor does not submit a Load-Side Relationship Certification (or the ISO rejects the Project Sponsor's Load-Side Relationship Certification) because the Project Sponsor is or is affiliated with a load serving entity or because the Project Sponsor receives or expects to receive revenues outside of ISO-administered markets from a load serving entity, the Project Sponsor is entitled to submit documentation and information as part of the New Capacity Qualification Package or the New Demand Capacity Resource Qualification package to demonstrate that, notwithstanding such a relationship with a load serving entity with regard to the New Capacity Resource, such load serving entity would be unlikely to realize a material, net financial benefit from any reduction in Forward Capacity Auction clearing prices resulting from entry of the New Capacity Resource in the Forward Capacity Market. If, after consideration of such documentation and information, the Internal Market Monitor determines that a load serving entity as described in this Section III.A.21.2.2 would be unlikely to realize a material, net financial benefit from any reduction in Forward Capacity Auction clearing prices resulting from entry of the New Capacity Resource in the Forward Capacity Market, then the Internal Market Monitor will not subject the requested lowest offer price to the mitigation described in Section III.A.21.2.3. For the avoidance of doubt, a Project Sponsor may not utilize the provisions of this Section III.A.21.2.2 if it receives or expects to receive any revenues from a state, or from a political subdivision of a state that is not also a load serving entity, that relate to the development, operation, control, or output of the New Capacity Resource.

As part of the documentation and information the Project Sponsor submits pursuant to this Section III.A.21.2.2, the Project Sponsor must include in its documentation and information a disclosure of any and all direct or indirect relationships or arrangements with a load serving entity regarding the New Capacity Resource and any other information necessary for the Internal Market Monitor to make the determination described in this Section III.A.21.2.2.

III.A.21.2.3. Consequence of Failing the Conduct Test and Failing to Rebut Presumed Incentive. If a requested lowest offer price from a New Capacity Resource fails the conduct test and the Internal Market Monitor does not determine the lack of a material financial net benefit to a load serving entity, as described in Section III.A.21.2.2, the New Resource Offer Floor Price calculated as part of the conduct test shall be used in the Forward Capacity Auction, as described in Section III.13.2.3.2.

As described in Section III.A.21.1.1, the mitigation described in this Section III.A.21.2.3 will not apply to a New Capacity Resource with an FCA Qualified Capacity that does not exceed the capacity threshold set forth in Section III.A.21.1.1, notwithstanding the results of any buyer-side market power review.

III.A.21.3. New Resource Offer Floor Prices.

For any New Capacity Resource for which the Internal Market Monitor is required to calculate a New Resource Offer Floor Price, the Internal Market Monitor shall use the calculation methodology described in this Section III.A.21.3.

A resource having a New Resource Offer Floor Price determined pursuant to this Section III.A.21.3 that is higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(a) When calculating a New Resource Offer Floor Price for any New Capacity Resource, the Internal Market Monitor shall enter all relevant resource capital and operating costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into a capital budgeting model and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The default model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm’s length between two unrelated parties). The model horizon shall be longer or shorter than 20 years for a resource’s New Resource Offer Floor Price calculation, if sufficiently documented in the offer information submitted pursuant to Sections III.13.1.1.2.2.3 or III.13.1.4.1.1.2.8. Adjustments to the model and calculation methodology will be made for certain types of New Demand Capacity Resources as described below in this subsection (a):

(i) For New Demand Capacity Resources(, the Internal Market Monitor will model discounted cash flows over the contract life.

(ii) For New Demand Capacity Resources that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, the Internal Market Monitor will include new equipment costs and annual operating costs, such as customer incentives and sales representative commissions, as incremental costs.

(iii) For New Demand Capacity Resources primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, the Internal Market Monitor will include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs as incremental costs.

(b) The Internal Market Monitor shall compare the requested lowest offer price to the capacity price estimate calculated pursuant to subsection (a), and the resource's New Resource Offer Floor Price shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package (as described in Sections III.13.1.1.2.2.3(a) and III.13.1.4.1.1.2.8(a)) to allow the Internal Market Monitor to make the determinations described in this Section III.A.21.3. If the supporting documentation and information is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource shall not be included in the Forward Capacity Auction.

(v) If the Internal Market Monitor determines that the requested offer price is consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price.

(vi) If the Internal Market Monitor determines that the requested offer price is not consistent with the Internal Market Monitor's capacity price estimate, then the New Resource Offer Floor Price shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c).

III.A.21.4. Offer Prices for New Import Capacity Resources.

(a) All New Import Capacity Resources (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be subject to the pivotal supplier test in Section III.A.23.

(b) For any New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 that does not seek to specify a price below which it would not accept a Capacity Supply Obligation that is at or above the Dynamic De-List Bid Threshold, the resource's offer price shall be $0.00/kW-month, subject to the provisions of Section III.13.2.3.2(a)(v).

(c) For any New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and seeks to specify a price below which it would not accept a Capacity Supply Obligation that is at or above the Dynamic De-List Bid Threshold, the Internal Market Monitor shall calculate an Internal Market Monitor-determined offer price for the resource using the methodology for calculating New Resource Offer Floor Prices set forth in Section III.A.21.3. For any New Import Capacity Resource that is not subject to the pivotal supplier test in Section III.A.23, the Internal Market Monitor shall calculate a New Resource Offer Floor Price using the methodology set forth in Section III.A.21.3, if such a calculation is required for the resource under Section III.A.21.2 above.

(d) For any New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found to be associated with a pivotal supplier, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7, the resource's offer prices shall be reduced to equal the lower of (1) the prices determined by the Internal Market Monitor pursuant to subsection (c); or (2) the offer prices as revised pursuant to Section III.13.1.3.5.7. For any New Import Capacity Resource that is subject to the pivotal supplier test and is found not to be associated with a pivotal supplier, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7, the resource's offer prices shall be reduced to the prices revised pursuant to Section III.13.1.3.5.7.

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

(a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources in the Rest-of-Pool Capacity Zone;

(b) For each modeled import-constrained Capacity Zone, the greater of:

  (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;

  (2) the Local Sourcing Requirement of the import-constrained Capacity Zone;

(c) For each modeled nested export-constrained Capacity Zone, the lesser of:

  (1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the nested export-constrained Capacity Zone plus, for each external interface connected to the nested export-constrained

Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;

(2) the Maximum Capacity Limit of the nested export-constrained Capacity Zone;

(d) For each modeled export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, the lesser of:

(1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the export-constrained Capacity Zone, excluding the total FCA Qualified Capacity from Existing Generating Capacity Resources and Existing Demand Capacity Resources within a nested export-constrained Capacity Zone, plus, for each external interface connected to the export-constrained Capacity Zone that is not included in any nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, excluding the contribution from any nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

(2) the Maximum Capacity Limit of the export-constrained Capacity Zone minus the contribution from any associated nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

(e) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of:

(1) the capacity transfer limit of the interface (net of tie benefits), and;

(2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(1) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources located within the import-constrained Capacity Zone; and

(2) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone or nested export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone or nested export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.

(b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Capacity Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than

ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, then

iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

<u>EXHIBIT E</u>

EMM Report

Evaluation of Changes in the Minimum Offer Price Rules on Financial Risk in New England

Prepared By:

POTOMAC
ECONOMICS

External Market Monitor
for ISO-NE

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PREFACE

Potomac Economics serves as the External Market Monitor for ISO-NE. In this role, we are responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by ISO-NE.[1] In this report, we provide our evaluation of the impact of eliminating MOPR on the financial risk and how certain market parameters need to be adjusted to provide the required incentives to merchant investors.

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1 The functions of the External Market Monitor are listed in Appendix III.A.2.2 of "Market Rule 1."

EXECUTIVE SUMMARY

ISO-NE is working with its stakeholders to eliminate or modify the Minimum Offer Pricing Rule ("MOPR") in time for the Forward Capacity Auction 17 ("FCA-17"). Eliminating MOPR would lower the barriers to participation in capacity markets by resources that are supported by the New England states. However, an important consequence of eliminating the MOPR is an increase in the financial risk for merchant resource owners. The ISO requested the EMM evaluate this risk and how it can be accounted for in the market. This report describes our assessment of the increase in the financial risk to merchant investors if the MOPR is eliminated.

The capacity market is designed to provide efficient incentives for the investment needed to satisfy resource adequacy needs. In other words, as capacity margins fall and new investment is needed to satisfy New England's resource adequacy requirements, an investor must find it attractive to invest in a new resource. This requires that the investor expect future capacity revenues to cover its "Cost of New Entry" less revenues expected from the energy and ancillary services markets (i.e., "net CONE). As the volatility of future capacity revenues increase, the risk facing the investor and its net CONE increase.

One key factor that increases future revenue volatility and risk is out-of-market investment in resources are subsidized and result in a capacity surplus. Large quantities of such investments are planned by various states in New England to achieve decarbonization goals. The status quo MOPR moderates the price effects of such investment, reducing the associated risks to private investors in new resources. Accordingly, elimination of the MOPR provisions is likely to increase the risk facing merchant investment in New England. The purpose of this study is to recommend a change in the capacity market to account for this increased risk.

Higher financial risk affects key parameters that are used to determine the sloped capacity demand curves. The height of the demand curve depends on the Net CONE of a generic potential new entrant. The height is set to motivate investment needed to achieve a target level of reliability. Higher price volatility increases investment risk, which raises the cost of capital. Consequently, the Net CONE of the reference unit increases as price volatility increases.

Recent CONE studies have estimated the cost of capital of a new entrant based on a review of historical returns required by investors in power generation assets operating in regions with competitive wholesale markets. Each of these markets is either in a state jurisdiction with limited policy intervention or has limited the price effects of subsidized entry with a MOPR. Hence, the available historic data does not reflect the returns an investor would expect in a competitive power market without a MOPR and high levels of policy-driven investment. Hence, it is important to account for the effects of eliminating the MOPR provisions on the WACC.

To account for the incremental effects of eliminating the MOPR provisions on the WACC, we estimate the change in revenue volatility for the reference unit between the following two cases under long-term equilibrium conditions:[2]

- Case 1: Under the status quo MOPR rules, and
- Case 2: After elimination of MOPR rules.

Monte Carlo techniques are used to estimate the distribution of revenues for the reference unit in each of the two cases above. Changes in the volatility of the revenue distribution, as measured by metrics such as standard deviation and financial performance under downside market conditions, affect investors' Cost of Equity ("COE") and Cost of Debt ("COD") that together determine the WACC. We use the Capital Asset Pricing Model ("CAPM") and criteria employed by the credit ratings agencies to quantify the changes in the COE and COD.

To the extent possible, we maintain consistency with the recent CONE study in developing assumptions for our analysis. However, since the CONE Study does not explicitly characterize the volatility of revenues to the reference unit, we developed and presented to stakeholders our assumptions regarding several drivers of revenue volatility for the reference unit that are affected by state policies. Our scenarios regarding state policies are derived primarily from key documents supporting legislation and/or regulations.

Ultimately, based on the results of our model, we find that:

- There is a considerable difference in the volatility of revenues to the reference unit with and without the MOPR provisions.
- Removing the MOPR provision increases the After-Tax Weighted Average Cost of Capital ("ATWACC") by 225 basis points.
- Hence, we recommend an ATWACC of 10.51 percent to compensate investors for the higher investment risk in the No MOPR case.

This increase in ATWACC translates into a Net CONE of $8.66/kW-year (2025$), which is 16 percent higher than the current value of $7.47/kW-month. In addition, the Payment Performance Rate ("PPR") should be increased to $10,846/MWh from $9,337/MWh, to reflect the higher Net CONE of the reference unit.

[2] Under long-term equilibrium conditions, the total revenues to the reference unit are adequate to cover its capital and operating expenses.

I. Background and Scope of Study

New England relies on competitive wholesale market incentives to motivate investors to build new supply and maintain existing resources to satisfy resource adequacy needs. In recent years, New England states have increasingly promoted investment in clean resources to achieve ambitious environmental goals through long-term contracts and other out-of-market revenue streams. ISO-NE's Minimum Offer Pricing Rules ("MOPR") have moderated the price effects of out-of-market investment by imposing offer floors on resources receiving such revenues in some cases. In other cases, resources receiving out-of-market revenues have been able enter the market and sell capacity after participating in ISO-NE's Substitution Auction for sponsored resources.

The MOPR has helped ensure that out-of-market subsidies do not undermine the market's ability to attract investment needed for resource adequacy. However, the status quo MOPR could become a barrier to or increase the costs of States achieving their public policy goals. Accordingly, ISO-NE is working with its stakeholders to eliminate or modify the MOPR in time for FCA-17.

An important consequence of eliminating the application of the MOPR to public policy resources will be an increase in the financial risk for merchant resources. The increase in financial risk will result from increased volatility of market revenues after the MOPR is eliminated. This occurs because subsidized resources will be able to enter the market and sell capacity even when they are not economic and are contributing to a substantial capacity surplus. As a result, investors are likely to require a higher return on capital for merchant supply resources in the ISO-NE markets. The ISO requested the EMM evaluate this risk and how it can be accounted for in the market.

This report describes our assessment of the increase in the financial risk to merchant investors due to the elimination of the MOPR, and it is organized as follows:

- Section II discusses the key drivers of financial risk for investors in capacity resources, and how the MOPR tends to reduce this risk.
- Section III provides an overview of our methodology for quantifying the increase in financial risk due to elimination of the MOPR.
- Section IV describes our principles for determining the inputs and the key assumptions for the study, and
- Section V discusses the results and conclusions of our study.

II. Impact of MOPR on Financial Risk for Investors

When entry and exit of supply occurs that is not in response to market signals, i.e., occurring outside of the market through power purchase agreements, prices and other market outcomes become more volatile and difficult to forecast. MOPR provisions reduce this volatility by limiting the quantity of out-of-market new resources that will clear in the capacity market. Hence, capacity price volatility will likely increase when MOPR is eliminated, and merchant investors will demand a higher return for investing in New England. Since developers of intermittent generation and energy storage resources rely on a mix of out-of-market revenues and wholesale market revenues, even these developers will demand a higher return on investment.

In this section, we discuss:

- The principles of capacity market design, including the role of capacity market and the relationship between key market design parameters and price stability (subsection A),
- How price stability is affected by out-of-market entry (subsection B), and
- Our conclusions regarding how MOPR affects financial risk for investors (Subsection C).

A. Principles of Capacity Market Design

The purpose of the capacity market is to provide efficient incentives for the investment needed to satisfy resource adequacy needs. ISO-NE is responsible for satisfying a one-day-in-ten-years reliability standard. Energy and ancillary services markets typically do not provide adequate revenues to sustain reserve margins at that required level of reliability. The shortfall in revenue (after accounting for net revenues from the sale of energy and ancillary services) is called the "missing money", which the capacity market is designed to provide.

Capacity prices are primarily determined in annual auctions based on the supply offers from capacity resources and the demand curves. Supply and demand in the capacity auctions change from one year to next, while supply investments are long-lived (i.e., >20-year) assets that depend on revenues over the long-term. Hence, annual capacity auctions provide limited revenue certainty, making long-term expectations of auction clearing prices an important driver of investment.

The capacity demand curve has a downward-sloping shape so that as the capacity surplus increases, prices fall, and vice versa. This promotes the capacity price stability by encouraging new entry when needed for resource adequacy and discouraging entry when additional supply would provide less reliability value. The capacity demand curve is set by two key parameters:

- *Slope of Demand Curves* - ISO-NE sets the slope of the demand curve in proportion to the marginal reliability value of capacity.

- *Height of Demand Curves* - The height of the sloped demand curve depends on the Net CONE ("Cost of New Entry") of a generic potential new entrant (i.e., the demand curve unit). The height is set in order to motivate investment needed to achieve a target level of reliability, since a merchant investor must expect to recover Net CONE over the long-run as prices fluctuate. Key factors that affect the Net CONE include the estimated energy and ancillary service revenues, capital expenditures, economic life, and the cost of capital. Hence, higher price volatility increases investment risk, which raises the cost of capital and, consequently, Net CONE.

In the next subsection, we discuss how the volatility of revenues and the investment risk is influenced by out-of-market entry.

B. Market Risk with and without Out-of-Market Entry

Eliminating MOPR should enable a greater level of participation in the capacity market from state-sponsored resources that would have otherwise been subject to an Offer Floor Price. Increased out-of-market entry would result in higher market risk to revenues of merchant resources and other resources that rely at least partly on wholesale market revenues. The first part of this subsection illustrates how policy-driven investment and merchant investment tend to affect price volatility differently. The second part of the subsection highlights the tendency for state policy goals to change significantly over time with recent examples from New England.

In a market where new entry and exit are motivated only by market price signals, gradual demand growth and attrition of older inefficient supply leads to gradual new entry, resulting in predictable fluctuations in capacity surpluses and low price volatility. New supply investment is often lumpy, leading to some transitory periods of lower prices, so developers must consider such risks before making an investment. However, large and sustained surpluses are less likely. Overall, revenue forecasts reflect modest uncertainty because market responses generally dampen the effects of shocks.

In contrast, in a market with substantial out-of-market entry and exit, state policies (e.g. subsidized generation investment, electrification, etc.) may lead to large shocks in supply and demand. State-sponsored resource entry causes a larger shock to the system (relative to merchant developers) because the decisions about the timing and/or quantity of new entry are: (a) less dependent on the market conditions, about which participants can develop reasonable expectations, and (b) more dependent on the characteristics of the policy support, which may or may not have been anticipated.[3] Since the investment and retirement responses to these shocks can take years to materialize, out-of-market entry can significantly affect prices in the short to medium term. The MOPR provisions tend to moderate the price effects of out-of-market entry and exit.

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3 See Table 1 for the extent to which the states' procurement targets for certain key technologies have evolved in recent years.

1. *Effects of Policy-Driven Investment and Merchant Investment on Price Formation*

The following four figures illustrate how price volatility varies across markets according to the scale of out-of-market changes in supply and demand.

Figure 1 shows how the prices fluctuate over a five-year period around the Net CONE in a competitive market. In year 1, approximately 32,600 MW of existing supply is offered into the capacity market with delist bids of less than $5.30, leading to a clearing price of approximately $7/kW-month (see "P1"). In this scenario, a modest amount of load growth increases the demand every year (by ~0.8 percent), leading to a rightward shift in the demand curve each year from year 1 to year 5. A small amount of existing supply (~50 MW) is lost to attrition every year, contributing a small leftward shift to the existing supply from each year to the next. New supply resources offer capacity in the first year: 350 MW at $6.75, 350 MW at $7.00, 350 MW at $7.25, etc., and the Net CONE falls slightly for each new resource each year until it clears the market. One 350 MW project clears in each year from year 2 to year 5, leading the existing supply to shift right in each year after year 2. These conditions combine to produce clearing prices that fluctuate around the Net CONE as prospective new entrants make decisions to invest (or not) that naturally push prices towards Net CONE.

Figure 1: Capacity Price Formation in a Competitive Market
Gradual Demand Growth & Competitive Merchant Entry

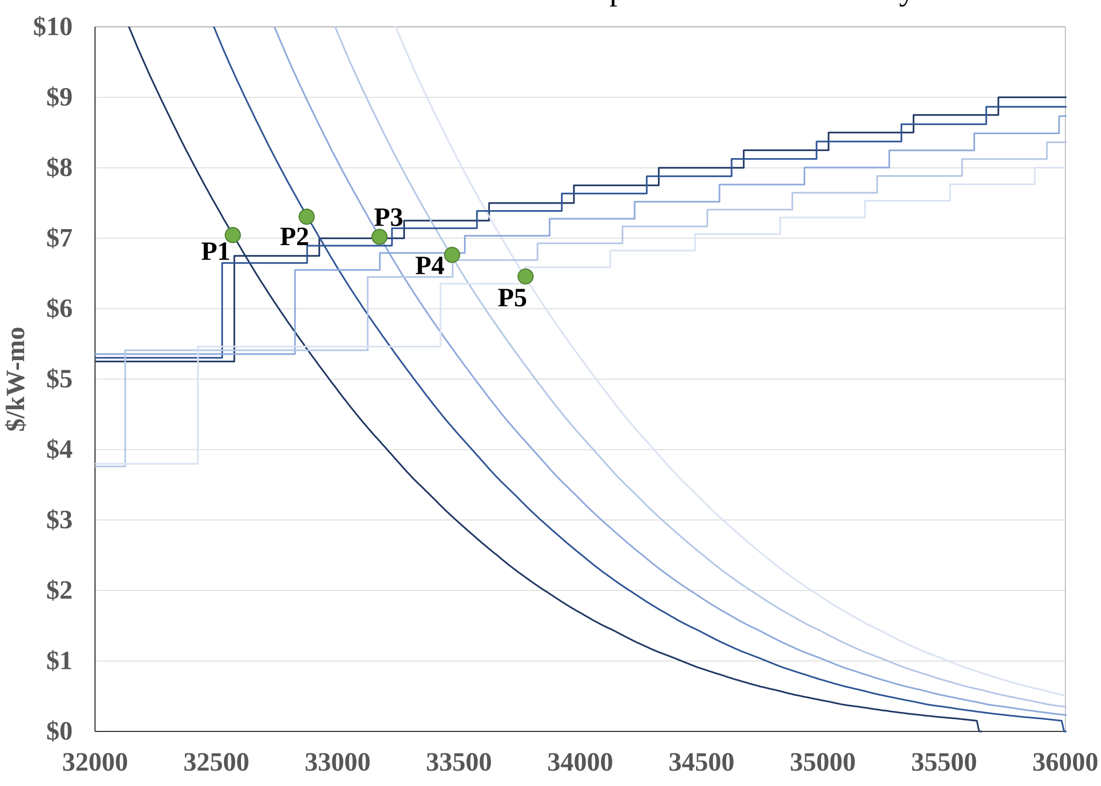
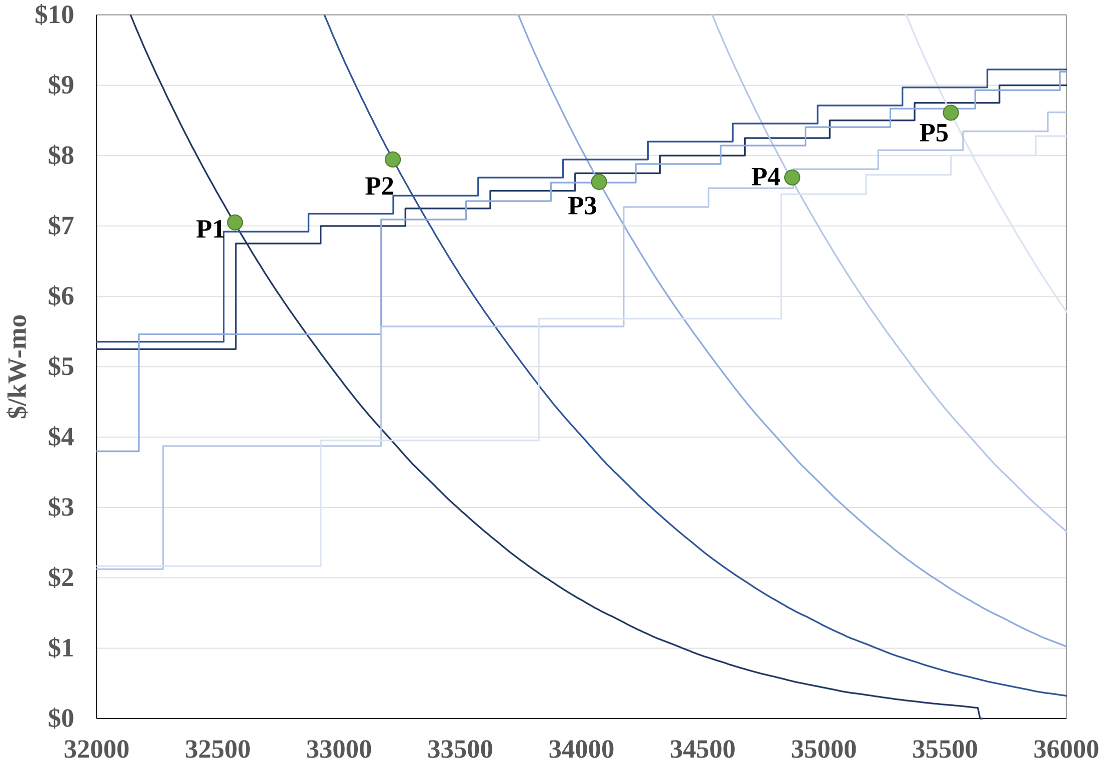


Figure 2 shows how the prices would tend to increase as a result of higher demand growth due to policies to electrify the demand sector (e.g., programs to install electric vehicle charging stations and convert residential gas furnaces over to heat pumps) and reduced supply investment due to policies to limit new investment in conventional resources. Figure 2 is similar to the previous figure, but demand growth is much faster (~2.5 percent per year) and the net cost of new entry rises 2 percent each year. This combination of policies would generally lead to higher and slightly more volatile prices than those shown in Figure 1.

Figure 2: Capacity Prices in a Market with Policy Intervention A
High Electrification & Limited New Fossil



In contrast, Figure 3 illustrates the outcomes in a market with substantial out-of-market entry that is insensitive to capacity market conditions (i.e., where out-of-market entry exceeds demand growth for a sustained period of time). Each year after year 1, it shows nearly 1 GW of new supply entering the market as price-takers despite the steep year-over-year declines in capacity prices. In year 2, the clearing price ("P2") is set at the going-forward cost of existing capacity, but prices continue to fall each year as higher cost existing resources leave the market. This scenario illustrates how very low prices can occur for a sustained period when the amount of out-of-market entry exceeds the amount of price-responsive supply in the market.

Figure 4 illustrates how the MOPR provisions can reduce this downside risk to investors by incorporating MOPR rules (with a Substitution Auction) into the scenario shown in Figure 3. In each year, the clearing price is set by unsubsidized resources clearing, while the substitution auction allows new subsidized resources to enter the market as long as their capacity is matched by an equal amount of retirement, causing prices to remain much closer to competitive levels.

Figure 3: Capacity Prices in a Market with Policy Intervention B
High Out-of-Market Investment in Supply

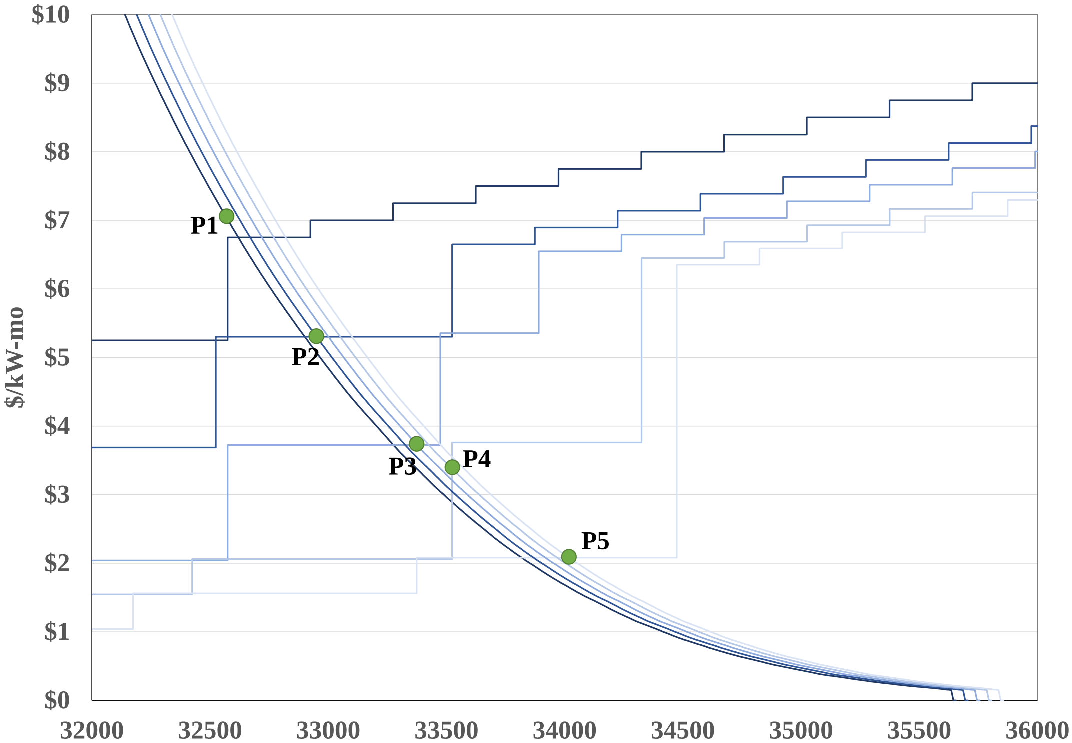
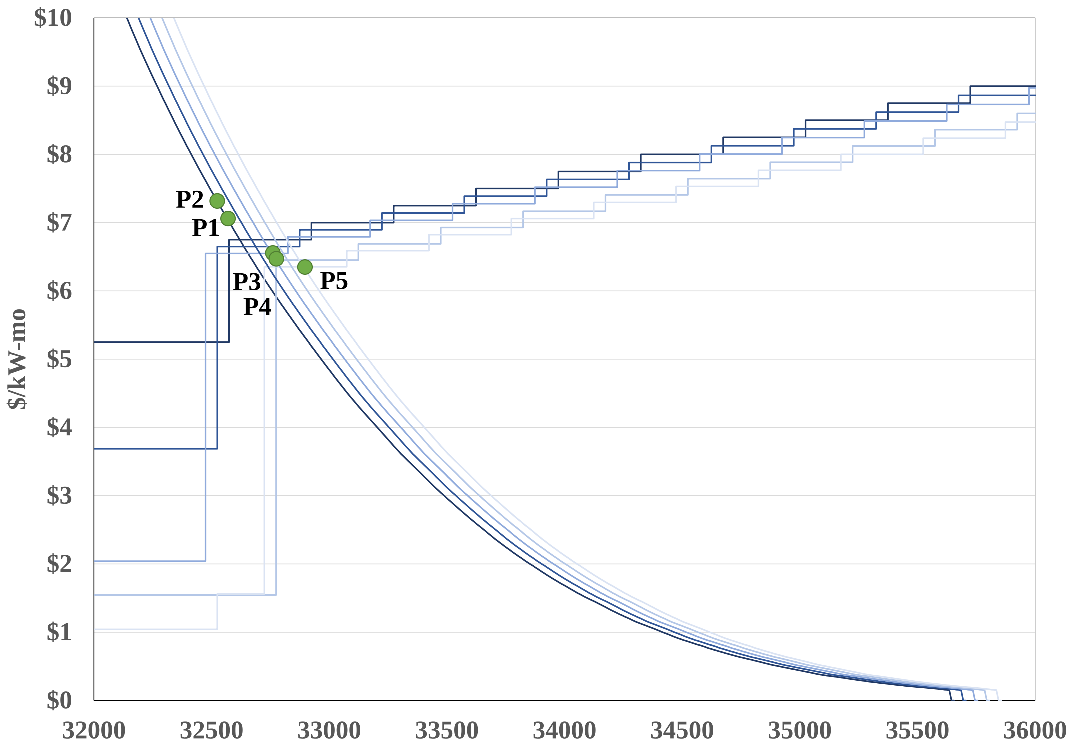


Figure 4: Capacity Prices in a Market with Policy Intervention B and MOPR
High Out-of-Market Investment in Supply with a MOPR



2. *Potential Out-of-Market Entry in New England*

The New England states have set aggressive procurement targets in legislation and/or regulations for several different clean resource categories. In recent years, these procurement targets have significantly evolved in their scale, the timing of implementation, and the specific technologies that are targeted. As merchant investors consider whether to build new generation assets with a useful life extending past 2040, they must consider current targets and the likelihood that these will be modified over the time horizon of the investment.

The following table shows the states' current procurement targets for key technologies that could have a considerable effect on the supply-demand balance in the capacity market. The table also shows how these targets have changed over time and/or the progress towards the targets.

Table 1: State Procurement Targets for Key Technologies

Resource Type	State	Target
Offshore Wind	MA	2016 - 1600 MW target procured by 2027 2018 - 3200 MW target installed by 2035 2021 - 4000 MW target procured by 2027
	CT	2018 - 300 MW procurement 2019 - 800 MW procurement 2019 - 2000 MW procured by 2030
	RI	2018 - 400 MW procurement 2021 - 1000 MW total solicitation (expected)
Energy Storage	MA	2016 - 200 MWh by 2020 2018 - 1000 MWh by 2025 2018 - 1600 MW solar through SMART, incentives for co-located storage 2020 - 3200 MW solar through SMART, incentives for co-located storage 2020 - Clean Peak Standard, approx. 1700 MW expected by 2030
	CT	2021 - 1,000 MW by 2030
	ME	2021 - 400 MW by 2030
HQ Line	MA	2017 - 9.45 TWh by 2022 2018-2021 - no project cleared FCA through FCA-15 (2024/2025)

The quantity of sponsored policy resources is significant, so these procurements could have a large impact on the supply-demand balance in future years. However, the targeted quantities and the dates when resources must be procured or must begin operating have changed dramatically over time, making them difficult to predict for a prospective merchant investor. For instance:

- OSW targets have grown significantly from 1.6 GW in 2016 to over 6 GW in a period of four years, with the possibility of additional increases in targets. In addition, the timeframe for the targets to be reached have also advanced.

- No states in New England had large energy storage procurement targets prior to 2018. However, in the past four years, three states have adopted a total of 1,400 MW plus 1,000 MWh in explicit storage targets, and Massachusetts has adopted large but uncertain storage entry objectives under the SMART and Clean Peak Standard programs. We estimate that over 4 GW of energy storage could enter under *existing* state programs by 2030, but additional entry is possible.
- While the original target date for a transmission line that would allow importation of 1.2 GW of hydropower from Quebec was late-2022, the line has not sold capacity through FCA-15, which is for 2024/25.

All of the above targets are likely to impact the supply-demand balance in future years. As demonstrated by the table above, the quantity and timing of the entry of sponsored policy resources has varied considerably. These changes would have been difficult to predict many years in advance. In the absence of the MOPR, the difficulty in predicting changes in these policy targets will lead to increased price volatility.

C. Conclusions

The capacity market is designed to provide efficient incentives for the investment needed to satisfy resource adequacy needs. In a competitive market, supply offers and capacity demand curves each contribute to price stability. Price-responsive supply offers moderate shocks to the market by responding to high prices with new entry and low prices with retirement. The demand curves also contribute to price stability because the sloped shape of the demand curve causes prices to increase as the capacity surplus falls, and vice versa.

Investors that rely on wholesale market revenues respond to supply and demand shocks in a manner that dampens their effects. However, high levels of investment that disregards wholesale prices may exhaust the capability of the market to respond to shocks, and policy-driven investment tends to increase these shocks to the market. The status quo MOPR reduces the resulting price effects, while elimination of the MOPR will tend to increase investment risks. Accordingly, elimination of the MOPR provisions is likely to increase the risk of investing in New England on a merchant basis. We discuss our methodology for quantifying this increase in risk and the associated increase in the cost of capital in the next section. This recommended increase in the cost of capital will allow the capacity market to facilitate investment and retirement decisions that will satisfy New England’s resource adequacy needs.

III. Study Methodology

Recent CONE studies have estimated the cost of capital of a new entrant based on a review of historical returns required by investors in power generation assets operating in regions with competitive wholesale markets. Each of these markets is either in a state jurisdiction with limited policy intervention or has limited the price effects of subsidized entry with a MOPR. Hence, the available historic data does not reflect the returns an investor would expect in a competitive power market without a MOPR and high levels of policy-driven investment. Hence, it is important to account for the effects of eliminating the MOPR provisions on the WACC.

This section of the report describes our model for estimating how future price volatility would be affected by *a change* in market rules (i.e., elimination of MOPR). Specifically, our model estimates how a change in price volatility resulting from MOPR elimination would change:

- The cost of equity using the Capital Asset Pricing Model ("CAPM"); and
- An investor's cost of debt based on criteria employed by credit rating agencies.

In this section, we: (a) summarize how the WACC was estimated under status quo rules, i.e., with MOPR in place (subsection A), and (b) discuss our methodology and the modeling steps for estimating WACC if MOPR is eliminated (subsection B).

A. WACC under the Status Quo MOPR

The ISO recently estimated the cost of capital parameters as part of its estimates for the Net CONE of the reference unit for FCA-16. The consultants estimated a COE of 13 percent, a COD of 6 percent, and a debt ratio of 55 percent for a new merchant entrant in the ISO-NE control area. The study was conducted in 2020 based on a review of historic data and prevailing financial market conditions. Accordingly, the WACC developed as part of the 2020 CONE study reflects the existence of the current MOPR provisions.

The consultants estimated the WACC parameters in the CONE study in the following manner:[4]

- The COE was estimated using the results of the CAPM that considered the historical returns on equity for a peer group of IPPs.
- The COD was determined based on a review of debt ratings of IPPs and historical bond yields for B and BB rated companies.
- The leverage ratio was estimated based on a review of the capital structure of a peer group of companies over a historical period.

4 See *Section 4: Financial Assumptions* of the December 2020 report *ISO-NE CONE and ORTP Analysis*.

B. Estimated Impact of MOPR Elimination on the WACC

As noted in the introduction to this section, there are no available historic comparables for a competitive power market that motivates merchant new entry without a MOPR. Accordingly, a new approach is needed for estimating the effect on the WACC for new entrants of eliminating the application of the MOPR provisions to public policy resources.

Our approach relies on quantifying the *change* in revenue volatility for the reference unit (under long-term equilibrium conditions) between the following two cases: (a) the status quo with the MOPR rules, and (b) after elimination of MOPR rules. We use Monte Carlo techniques to estimate the distribution of revenues for the reference unit in each of the two cases above. The policy assumptions and other supply and demand inputs are identical between the two cases, so this approach isolates the effect of the MOPR rule change on price formation. Changes in the volatility of the revenue distribution imply that the COE and COD should also change. We use CAPM and criteria employed by the credit ratings agencies to quantify the changes in the COE and COD.

We describe the theory underlying our methodology for estimating the change in COE and COD in subsections 1 and 2 below. Subsection 3 describes each of the modeling steps involved in estimating the change in the WACC that would result from eliminating the MOPR.

1. Revenue Volatility and Cost of Equity

As discussed in subsection A, the Capital Asset Pricing Model ("CAPM") was used in the CONE study to estimate the COE, and we adopted this value in the MOPR case. In the CAPM framework, investors require a higher return on equity from an asset whose returns are more volatile relative to an asset whose returns are less volatile, even if the expected average return from both assets is the same. Specifically, the CAPM framework implies that, all else being equal, the return on equity required by investors varies in direct proportion to the volatility of returns on the asset (as measured by the standard deviation of returns).[5]

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[5] Under the CAPM formulation,

Expected return of equity for an asset a = Risk-free Rate + β_a *x Market Risk Premium*

The CAPM β_a estimated as: $\beta_a = \sigma_a/\sigma_m \times \rho_{a,m}$ where,

β_a is the asset beta,

σ_a is the standard deviation of the asset's returns,

σ_m is the standard deviation of the market's returns,

$\rho_{a,m}$ is the correlation coefficient of market's returns to the asset's returns.

Therefore, if the standard deviation of the asset's returns increase, the beta of the asset will increase linearly, since the correlation coefficient of the asset's returns and the market's returns are expected to remain constant.

Thus, we estimate the COE in the No MOPR case in the following manner:

$$COE_{NoMOPR} = COE_{Reg} + COE_{NoMOPR\text{-}P}$$

$$COE_{NoMOPR} = COE_{Reg} + COE_{MOPR\text{-}P} \times StDev_{NoMOPR} \div StDev_{MOPR}$$

where,

COE_{NoMOPR} is the cost of equity in the No MOPR case,

COE_{Reg} is the cost of equity for a regulated entity, which we derive from recent orders setting regulated ROEs,

$COE_{NoMOPR\text{-}P}$ is the power market risk component of cost of equity with No MOPR,

$COE_{MOPR\text{-}P}$ is the power market risk component of cost of equity under the MOPR, which we derive as the difference between Merchant cost of equity under status quo conditions such that: $COE_{MOPR\text{-}P} = COE_{MOPR} – COE_{Reg}$,

StDev is the expected standard deviation of market returns in each case

In summary, this formulation bases the COE in the No MOPR case on the sum of two components:

- COE_{Reg} which is an estimate of the risk associated with investing in a unit that does not face any power market risk. This risk is assumed to be the same in the MOPR and No MOPR cases.[6]
- $COE_{NoMOPR\text{-}P}$ which is the component of the COE associated with the power market risk after the elimination of MOPR. We estimate this component by scaling up the power market risk component of the COE under status quo by the ratio of standard deviation of market returns in the two cases.

2. Revenue Volatility and Cost of Debt

As discussed in section II, the wholesale market will experience supply and demand shocks that could have larger price effects after the MOPR is eliminated. In particular, the likelihood of experiencing periods of severely depressed wholesale prices is expected to increase. In addition to expected prices, credit rating agencies consider a variety of downside or stressed conditions when evaluating the ability of a project to satisfy its debt obligations and assigning a rating for

[6] For instance, the project development risk, risk of fuel supply disruptions, and performance risk are unlikely to be different across the MOPR and No MOPR cases.

it.[7] Therefore, even if two projects have the same revenues on an expected basis, a project that faces a larger downside risk (i.e. the one whose revenues are likely to be lower under stressed conditions) would receive a lower rating, which would result in a higher COD.

While the Net CONE Study used historic data on publicly traded companies with balance sheet financing to estimate the cost of capital for merchant generation investments under the current market rules., our model uses principles of project finance to estimate how changes in the distribution of revenues would be expected to affect the cost of capital for merchant generation investments. The primary metric we use to analyze the ability of a project to satisfy its debt service obligations is the Debt-Service Coverage Ratio ("DSCR"), which is the ratio of a project's operating income to its debt service payments.[8] A high DSCR generally leads to a better credit rating, while a low DSCR leads to (a) a lower credit rating and/or (b) an increase in liquidity requirements for the project. We utilize the following guidance (Table 2) from Fitch Ratings regarding how a change in the expected DSCR of a project would affect its debt rating and COD. The table examines the ability of a project to cover its debt service under conditions "consistent with the expected bottom" of an economic cycle, which is known as a "Rating Case".[9]

Table 2: Fitch Ratings Guidance regarding Indicative Coverage Ratios[10]

Fitch Rating Case (x)	Revenue risk KRD	'A–' DSCR profile	'BBB–' DSCR profile	'BB–' DSCR profile[a]	'B–' DSCR profile
No Merchant Exposure	'Stronger'	1.5	1.3	1.15	1
	'Midrange'/'Weaker'	1.6	1.4	1.2	1
Full Merchant Exposure	'Weaker'	n.a.	1.80 and higher	1.4	1

7 For instance, Standard & Poor's criteria for assessing operating risk considers the performance of the project under market trough conditions and the difference between the expected and trough market conditions. See pp. 44-48 and pp. 67-74 of Standard &Poor's *Project Finance: Project Finance Operations Methodology* published on September 16, 2014.

8 While rating agencies consider various qualitative and quantitative criteria, the DSCR is a key metric that is utilized by all three rating agencies in evaluating loans. Fitch Ratings and S&P publish explicit guidance that maps a project's DSCR to a debt rating. DSCRs can quantify the volatility in revenues over a portion of the term of a loan rather than the entire term, making them well-suited to our approach of modeling conditions over several years that are representative of long-term equilibrium conditions. This differs from other metrics used by ratings agencies which measure the project's ability to service its debt in aggregate over the loan term.

9 In addition to considering cash flows stresses due to market price volatility, the Rating Case also includes other stresses associated with higher operating costs, worse than expected performance, and higher rate of outages. See Fitch Ratings' guidance for development of Rating Case on pages 9-10 of its *Thermal Power Project Rating Criteria* published in June 2021.

10 The table shows the guidance for a fully amortizing loan structure, which is similar to the treatment of debt in the model used to determine the Net CONE. However, most project finance-based merchant projects rely on a Term B Loans ("TLB") structure for their debt. TLBs are characterized by a modest paydown of

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The table shows that as the DSCR in the Rating Case decreases, the project's rating (and its COD) worsens. A merchant generator in a deregulated wholesale market would be analyzed using the row for "Full Merchant Exposure". To develop the Rating Case DSCR and estimate the COD in the No MOPR case, we:

- Adjust the revenue distributions (in both the MOPR and No MOPR cases) by increasing the fixed costs and reducing the heat rate of the unit to reflect worse than expected performance based on guidance from rating agencies,[11]
- Determine the portion (i.e., percentile range) of the revenue distribution where the DSCRs in the MOPR case correspond to the B+/BB- range (i.e., 1.27 to 1.53 based on the guidance in Table 2), which is the rating range assumed for developing the COD in the recent CONE study,
- Estimate Rating Case revenue and DSCR in the No MOPR case based on the revenues from the same percentile range of the revenue distribution determined in the previous step, and
- Map the estimated Rating Case DSCR in the No MOPR case to a specific COD using Table 2 and the yields for B and BB-rated corporate bonds.[12]

In summary, we first the baseline level of market stress in the MOPR case that is associated with the COD from the CONE Study, and then we stress the project cash flows to a similar degree in the No MOPR case to determine the DSCR and COD in the No MOPR case.

To illustrate this methodology, consider Figure 5 which shows (a) the illustrative distributions of the total revenues for the reference unit in the MOPR case and in the No MOPR case before adjusting capital cost parameters, (b) the portion of the distribution where the revenues correspond to a B+/BB- rating (i.e. where the DSCR is between 1.27 and 1.53) in the MOPR

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principal during the loan term (typically 5-7 years) and a large bullet payment at the end of the term. The bullet payments at the end of the term are usually refinanced using another TLB or paid down through a fully amortizing loan, depending on the remaining life of the project.

The rating of a project that relies on TLB debt could be determined by the credit metrics in the TLB phase or in the refinance phase. As with a fully amortizing loan, DSCRs are a useful metric to evaluate a project in its TLB phase. If the DSCRs are robust in the TLB phase, the project's rating may be determined by its evaluation in the refinance phase. Other metrics such as Project Life Coverage Ratio, Debt/ EBIDTA, CFADS/ Debt that help identify issues with the size of the leverage are typically used to evaluate the refinance phase of the project. However, unless the market environment is assumed to improve with time, high levels of leverage at the end of the TLB phase are likely to translate into low annual DSCRs in the refinance phase. Hence, for our analysis which looks at a time period shorter than the full term of typical TLB debt, the DSCR-based guidance for fully amortizing loans provides a reasonable basis for estimating how changes in volatility would affect the project's debt rating.

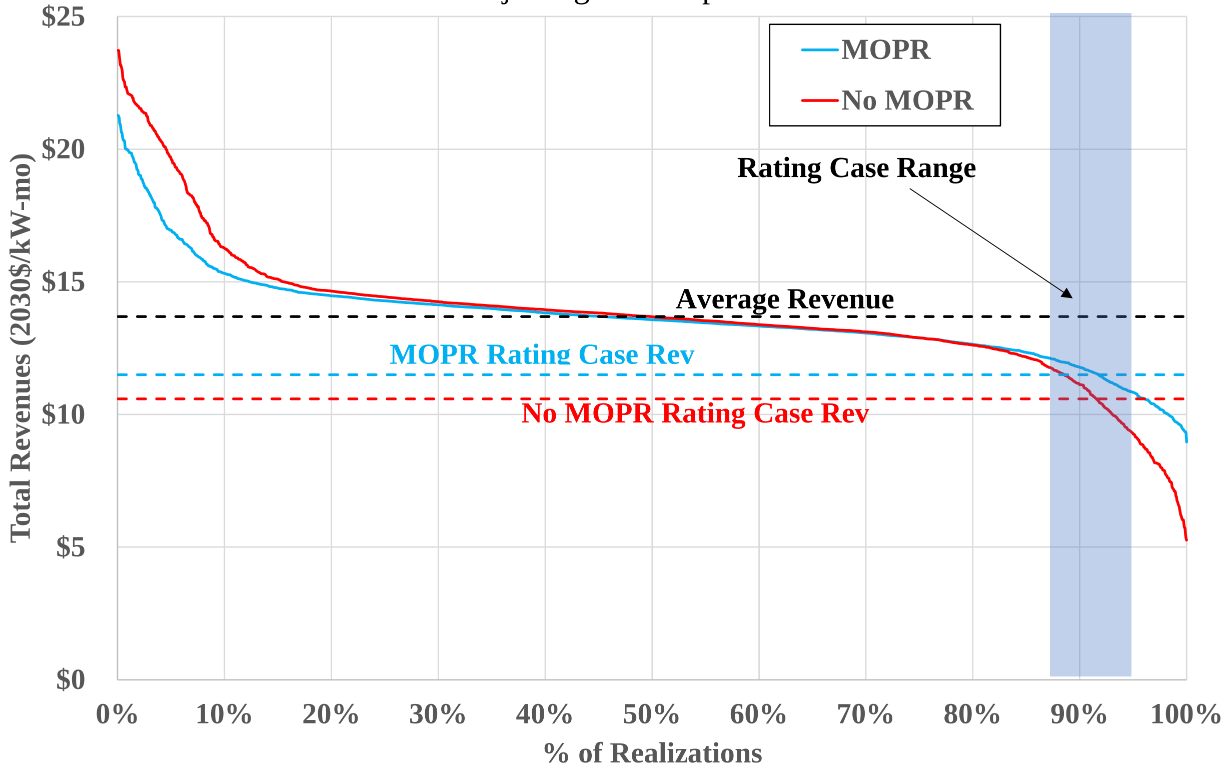
11 See table on *Indicative Rating Cases — Thermal Projects* on page 10 of Fitch Ratings' *Thermal Power Project Rating Criteria* published in June 2021. See *Table 4 - Market Exposure: Market Downside Case Guidance For Power Projects* and *Table 8 - Power Projects: Standard & Poor's Downside Case Assumptions Guidance*, Standard & Poor's *Project Finance: Key Credit Factors For Power Project Financings* published on September 16, 2014.

12 See *Financial Assumptions.xlsx* file in the *Inputs* folder for data on bond yields.

case (which is labeled as "Rating Case Range"), and (c) the average and Rating Case revenues in the MOPR and No MOPR cases.

Figure 5: Illustrative Revenue Distributions in the MOPR and No MOPR Cases

Before adjusting WACC parameters



In the above figure, the DSCRs commensurate with a B+/BB- rating in the MOPR case correspond to approximately 5th to 12th percentile of the revenue distribution (shown as the Rating Case range). Although the average revenue across the 2000 realizations is the same in both MOPR and No MOPR cases, the average revenue in the Rating Case range is eight percent lower in the No MOPR case.

Table 3 illustrates the derivation of the Rating Case DSCRs in the MOPR and No MOPR cases. It shows that the Rating Case DSCR declines from 1.41 in the MOPR case to 1.10 in the No MOPR case. To map the Rating Case DSCR into a COD, we developed a function that relates these two parameters considering the corporate bond yields in the first half of 2020 and the Fitch Ratings guidance contained in Table 2.[13]

Figure 6 shows: (a) our assumed COD as a function of the Rating.Case DSCR, and (b) the COD for a Rating Case DSCR of 1.10. As shown, we estimate the COD in the No MOPR case in our illustrative example to be 8.1 percent.

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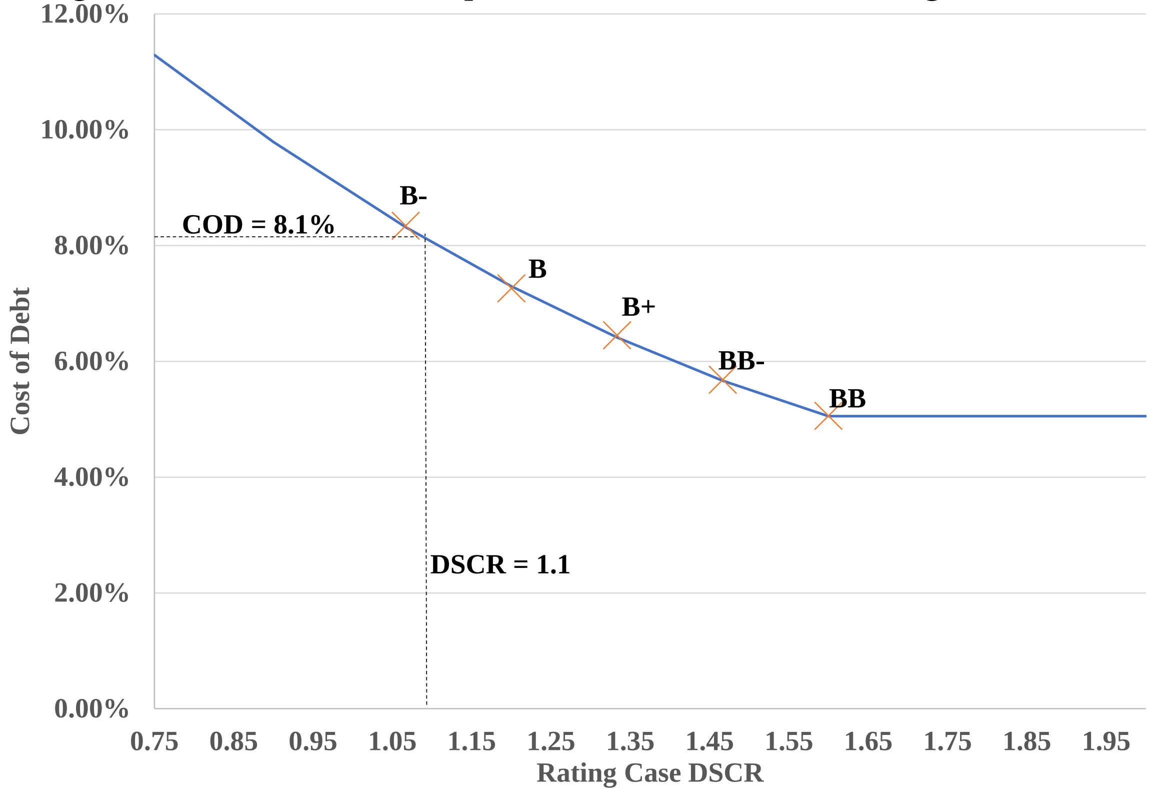
13 See *Financial Assumptions.xlsx* file in the Inputs folder for data on bond yields.

Table 3: Illustrative Calculation of DSCR in the MOPR and No MOPR Rating Cases

2030$/kW-mo	Notes	Base	Rating Case MOPR	Rating Case No MOPR
Total Revenues	[1]	$ 13.7	$ 10.6	$ 9.6
Fixed costs	[2]	$ 5.3	$ 6.0	$ 6.0
Taxes	[3]	$ 1.0	$ -	$ -
Net Cash Flow	[4] = [1] - [2] - [3]	$ 7.4	$ 4.6	$ 3.6
Debt Service	[5]	$ 3.3	$ 3.3	$ 3.3
DSCR	[4]/[5]	2.25	1.41	1.10

[1] Includes Capacity, PFP, scarcity and EAS revenues. All revenues derated by 6% to account for lower availability and EAS revenues derated by 2.5% to account for higher heat rate
[2] Fixed O&M in Rating Case increased by 12% per guidance from S&P and Fitch (relative to base case) to reflect performance stress
[3] Federal and State income taxes

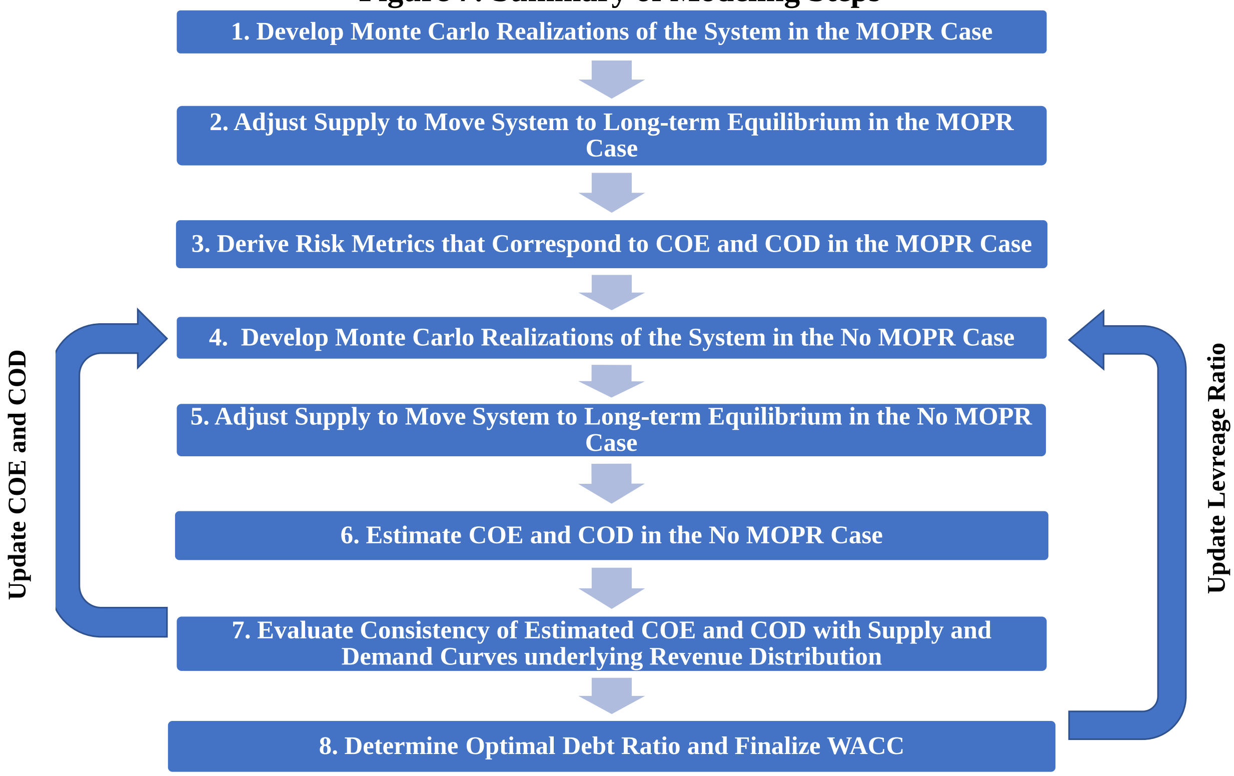
Figure 6: Assumed Relationship between Cost of Debt and Rating Case DSCR



3. Estimating Change in WACC due to Eliminating MOPR – Modeling Steps

In this part of the subsection, we detail each of the steps used in the model for estimating the change in WACC that is due to MOPR elimination. Figure 7 shows a flowchart that summarizes these steps.

Figure 7: Summary of Modeling Steps



1. Develop Monte Carlo Realizations of the System in the MOPR Case

We use Monte Carlo simulation techniques to generate a probability distribution of the revenues to the reference unit and derive the relevant risk metrics in the MOPR case. We develop 2000 realizations of supply and demand curves and estimate the revenues to the reference unit (capacity, PFP and energy and ancillary services revenues) in each realization.[14] In each realization, we assume that the sponsored policy resources are subject to an Offer Floor Price that is based on the resource's Net CONE.

The sources of uncertainty in our model include uncertainty in the following variables:[15]

- Peak load forecast

14 Given our assumptions about the capacity supply offers from existing units, the revenue in each Monte Carlo realization should be interpreted as the average over three years.

15 See section IV for a discussion of the values assumed for each of these variables.

- Quantities of sponsored policy resources (offshore wind, energy storage, and solar resources)
- Cost of energy storage resources
- Existence of the NECEC line
- Capacity import offers from NYISO
- Quantity of feasible new fossil fuel-fired CTs
- Number of shortage hours given a surplus capacity level, and
- Energy and ancillary services revenues given a surplus capacity level

2. Adjust Supply to Move System to Long-term Equilibrium in the MOPR Case

The Net CONE used to set the capacity demand curves (and several of its input parameters such as energy and ancillary services revenue offset and number of shortage hours), is determined as the "missing money" of the reference unit under long-term equilibrium conditions. Accordingly, for the purpose of our analysis, we consider a wholesale market under long-term equilibrium conditions, where:

Annualized Gross CONE of Reference Unit = Total Revenues of the Reference Unit

However, the assumed characteristics of supply and demand may not result in adequate revenue to the reference unit on an expected basis. Hence, to model a system at long-term equilibrium, we solve for an adjustment to the supply stack that removes capacity from high-cost existing resources until the average revenue to the reference unit across the 2000 realizations equals its annualized Gross CONE based on its assumed COE and COD.

3. Derive Risk Metrics that Correspond to COE and COD in the MOPR Case

Based on the distribution of revenues across the 2000 Monte Carlo realizations in the MOPR case, we derive the financial risk metrics that correspond to the COE and COD under the status quo rules.[16] Specifically:

- We determine the standard deviation of the revenues of the reference unit, which is assumed to correspond to the power market risk component of the assumed COE ($COE_{MOPR\text{-}P}$) in the MOPR case.[17]
- We determine the Rating Case range of the revenue distribution as the portion of the distribution (i.e., upper and lower percentile values) where the DSCR corresponds to the assumed COD (i.e., the COD determined in the CONE study).

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16 We assume the COE and COD in the MOPR case to equal the values developed in the most recent CONE study.

17 We estimate the power market risk component to be 300 basis points. See *Financial Assumptions.xlsx* file in the *Inputs* folder for the inputs and calculations underlying the assumed power market risk component.

4. Develop Monte Carlo Realizations of the System in the No MOPR Case

To develop the Monte Carlo realizations in the No MOPR case, we start with the supply curves for all the realizations from the MOPR case, and then we remove any mitigation that was applied to sponsored policy resources. We remove the mitigation by setting the offer floors of all sponsored policy resources to $0/kW-mo. All other inputs to the Monte Carlo simulation remain the same across the MOPR and No MOPR cases, except for the supply adjustment that is required to move the system to long-term equilibrium conditions.

5. Adjust Supply to Move System to Long-term Equilibrium in the No MOPR Case

Similar to the MOPR case, we remove capacity from higher-cost existing resources to ensure that the long-term equilibrium condition is satisfied in the No MOPR case also. Given the larger surplus in the No MOPR case, a larger quantity of existing supply (relative to the MOPR case) will have to be removed to set up the system under long-term equilibrium conditions.

6. Estimate Observed COE and COD in the No MOPR Case

We use the revenue distribution to estimate the observed COE and COD in the No MOPR case.

- For COE, we calculate the standard deviation of the revenues in the No MOPR case and use the relationship discussed in subsection B.1 to estimate the observed COE in the No MOPR case.
- For COD, we estimate the Rating Case DSCR in the No MOPR case based on the average revenues from the Rating Case range of the distribution determined in step 3 above, and we use the assumed relationship between Rating Case DSCR and COD (see Figure 6) to estimate the observed COD in the No MOPR case.

7. Evaluate Consistency of Observed COE and COD with Assumed Values underlying Revenue Distribution

If the observed values for COE and COD are higher than the initial assumed values in the No MOPR case, then the analysis is repeated using different assumed values of COE and COD. An increase in the assumed COE and COD affects both the supply and demand curves in the next iteration of the No MOPR case since:

- (a) A higher WACC increases the Net CONE of the reference unit and, consequently, the capacity demand curve, and
- (b) A higher WACC increases the capacity supply offers from new merchant resources.

Hence, the Monte Carlo simulation is repeated (by returning to step 4) using updated supply and demand curves based on the last observed COE and COD values. This is repeated until the observed COE and COD at the end of step 7 converge to the values assumed in step 4. Thus, we gradually adjust the COE, COD and the supply adjustment (see step 5 above) and iterate until the conditions below are satisfied:

- The WACC used to calculate demand curve and supply offers is consistent with the WACC implied by volatility of revenues, and
- The Gross CONE of reference unit equals the average total revenues of the reference unit.

8. Determine Optimal Debt Ratio and Finalize WACC

Given the increased likelihood of low prices in the No MOPR case, the COD in the No MOPR case tends to increase relative to the status quo. However, project developers can improve their debt rating and lower their COD by reducing leverage. This tends to reduce the overall WACC for the project.

While a lower debt ratio tends to lower the COD, it also affects other components of the WACC. So, the optimal value is chosen considering several trade-offs. Specifically, a lower debt ratio affects the overall WACC in the following ways:

- It reduces the required debt service payments, improving its DSCR and debt rating. This tends to reduce the WACC.[18]
- It increases the equity share of capital, and since COE is higher than COD, this tends to increase the WACC.
- It reduces the COE because the volatility of the returns to equity holders is lower at lower leverage levels.[19] This tends to reduce the WACC.
- It increases the COE because some of the default risk shifts to equity holders at lower leverage levels.[20] This tends to increase the WACC.

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18 In determining the COD at various leverage levels, we constrain the rating in the No MOPR case to BB. This is consistent with the guidance from S&P and Fitch Ratings which cap the debt rating in the B+ to BB+ range because of (a) limited historical data, and (b) high market uncertainty and larger difference between the expected and downside conditions. See discussion on page 11 of Fitch Ratings' *Thermal Power Project Rating Criteria* published in June 2021. See pp. 85-95 of Standard &Poor's *Project Finance: Project Finance Operations Methodology* published on September 16, 2014.

19 We utilize the extended Hamada equation (or the Conine equation) to characterize this relationship.

$$\beta_L = \beta_U \times (1 + (1-T) * (D/E)) - \beta_D \times (1-T) \times (D/E)$$

Where:

β_L – levered equity β

β_U – unlevered equity β

β_D – β of debt

T – tax rate

D/E – debt-to-equity ratio

20 *Id.*

We consider a range of alternative debt ratios for the No MOPR case, repeating steps 1 through 7 to determine the ATWACC for each debt ratio. This allows us to evaluate whether the total WACC in the No MOPR case could be reduced by lowering the amount of project debt. We estimate the final WACC parameters in the No MOPR case as the set of values (for COE, COD and debt ratio) that minimize the total ATWACC.

D. Conclusion

The WACC parameters developed as part of the recent CONE study, which relies on a review of historical financial market data, provide a proxy for the returns required by investors in merchant assets in ISO-NE markets with a MOPR. However, there are no available historic comparables for a competitive power market that motivates merchant new entry without a MOPR amid high levels of policy-driven investment. Hence, a different approach is needed to account for the effects of eliminating the MOPR provisions on the WACC.

Accordingly, we developed a model for estimating how future price volatility would be affected by a change in market rules (i.e., elimination of MOPR). Our model estimates how a change in price volatility resulting from MOPR elimination would change:

- The cost of equity using the Capital Asset Pricing Model ("CAPM"); and
- An investor's cost of debt based on criteria employed by credit rating agencies.

We described the overall approach and each of the steps in our model in this section. Nonetheless, the approach we developed for our study may not be required in future CONE studies. This is because future studies may be able to utilize the methods used by previous studies if sufficient historical market data is available after the MOPR is eliminated.

IV. MODEL INPUTS

Our model considers a range of inputs that affect the volatility of revenues to the reference unit. In this section, we discuss the principles for determining the model inputs (subsection A), and the key inputs/ assumptions underlying our model (subsection B).

A. Principles for Determining Model Inputs

The model is designed to estimate how a change in market rules would lead to a change in the financial risk for investors relative to the status quo. Consequently, the only difference between the MOPR case and No MOPR case is that the former uses the current offer floor mitigation rules for subsidized resources while the latter does not. Hence, the differences in financial risk between the two cases in the model are directly attributable to MOPR elimination rather than other factors.

The input assumptions for the model were developed considering the following:

- First, the model evaluates the capacity market under long-term equilibrium conditions where wholesale market revenues are *expected* to be just sufficient to recoup the cost of new entry to maintain the system at the 1 day in 10 years reliability standard. However, this does not guarantee revenues, since unforeseen factors cause revenues to be higher or lower than expected, making new supply investment risky.
- Second, the factors driving financial risk in the model should reasonably characterize circumstances that will contribute to revenue volatility during the (~20-year) investment horizon of resources deciding whether to sell capacity in the next few FCAs. We anticipate high levels of policy-driven investment to decarbonize the grid affecting both supply-side and demand-side participation.
- Third, it is important to avoid unnecessary complexity in any modeling exercise.

Given these considerations, we model the New England power system based on anticipated conditions around 2030. This timeframe has the advantage of being more clearly defined in New England State policy goals, allowing us to draw assumptions about potential policy pathways from State-sponsored publications. Conditions in 2030 are close enough to influence the near-term outlook of prospective investors, but it also serves as a proxy for market conditions that are likely to drive revenue volatility over the subsequent decade, which constitutes the medium and long-term view of investors.

To avoid unnecessary complexity, we model all of the new entry and retirement decisions leading up to 2030 in a single time step (rather than modeling decisions in each year leading up to 2030). The model estimates expected revenue volatility for a three-year rather than one-year period.[21] This is reasonable because investors rarely make significant retirement or new entry decisions based on a single year of very low or high revenues. Furthermore, three years aligns with the duration of a potential downside case that a lender would consider when evaluating a potential investment.

Since the model estimates how a change in market rules would increase or decrease financial risk, assumptions about the initial cost of capital in the MOPR case are based on the CONE study. We do not attempt to reevaluate financial risk in the MOPR case.

The next subsection of this report discusses the specific assumptions about supply and demand used in the model and how they were made consistent with the principles discussed above. We rely primarily on publications of New England States with detailed information about clean energy policies as the region transitions from a conventional fleet to one with high penetration of clean resources. There is some uncertainty regarding the specific policy measures and the timing and quantities of future new supply investment.[22] Hence, we model individual scenarios with probability weights that could affect the volatility of wholesale market revenues. Scenarios regarding state policies are derived primarily from key documents supporting legislation and/or regulations (e.g., the 2050 Decarbonization Roadmap). We also develop scenarios related to the competitive market responses of conventional new and existing resources and merchant battery storage resources.

B. Model Inputs

In this subsection, we discuss for each key model input, the relevance of the input, the values we assumed (and their sources) for our analysis.[23] This subsection organizes model inputs into the following categories:

- Capacity Demand
- Capacity Supply
- Reference Unit Revenues
- Financial Parameters

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21 While the term "volatility" is colloquially used to describe the up-and-down movement in prices, throughout this report, we use the term as it is defined in financial market theory as a measure of the uncertainty faced by financial market participants.

22 For instance, some policies allow flexibility regarding the target technology (e.g., whether the policy will focus on solar or wind to achieve certain targets). Furthermore, some states have made slower than expected progress toward stated policy goals (e.g., a project originally contracted with a utility to enter in 2024 might not enter the market until 2026).

23 In addition to the discussion in this section, we posted a folder (labeled *Inputs*) with files containing various inputs to the model.

4. Capacity Demand

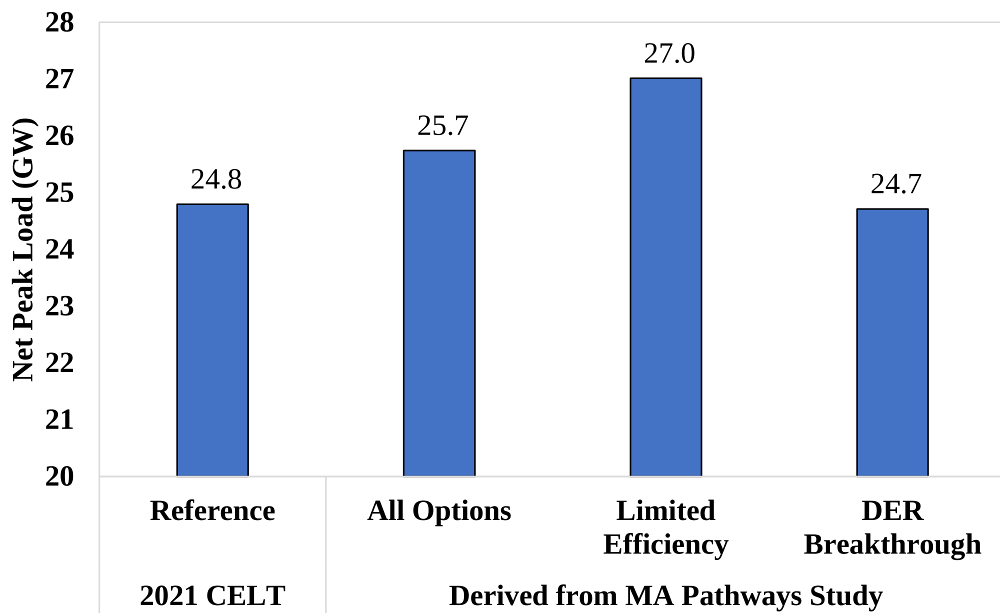
The primary driver of demand for capacity is the peak load forecast, which is affected by uncertainty in traditional gross load drivers (e.g., economic growth forecast), and other policy-driven factors such as adoption of energy efficiency, distributed resources, and the level of building and transportation electrification. Uncertainty in load forecast can have a significant impact on the expected outcomes, and hence, load forecast uncertainty is a key driver of uncertainty in revenues to merchant resources.

We modeled four peak load scenarios with equal probability weights in both MOPR and No MOPR cases. Our assumed scenarios are based on the ISO's 2021 CELT forecast for 2030, and the following three cases from Massachusetts' *Pathways to Deep Decarbonization Study*:

- *All Options* – This scenario assumes that decarbonization targets are met using the most economic set of resources using baseline cost assumptions for all technological options.
- *Limited Efficiency* – This scenario assumes fewer opportunities for energy efficiency when compared to the *All Options* scenario.
- *DER Breakthrough* – This scenario assumed greater penetration of behind-the-meter solar PV and flexible loads relative to the *All Options* scenario.

The following figure shows the peak load forecast levels in the four scenarios we modeled.

Figure 8: Peak Load Forecast Scenarios



5. *Capacity Supply*

Uncertainty regarding the quantity and cost of supply can also have a significant impact on the expected future outcomes. This part of the subsection describes our assumptions regarding the following categories of supply:

- Existing Resources
- Capacity Imports
- Offshore Wind Generation
- Energy Storage and Solar Resources
- New Combustion Turbines

The assumptions for each category are described below.

Existing Resources

We included supply from various types of internal capacity resources based on the actual cleared quantities in FCA-15. In developing our assumptions for capacity supply offers, we grouped resources according to their fuel type and/or prime mover type, and we reviewed the class average net going forward costs ("Net GFCs") from studies that have been conducted for NESCOE and NEPOOL.[24] We also considered the performance of these resource types in shortage events during the 2018 event, and their likely performance during shortages in a system with high renewable penetration. Ultimately,

- We assumed that the offers from most non-fossil resources will be low and in the range of $0 to $1/kW-month.[25]
- We assumed that offers from CCs and CTs will range from $1-$4/kW-mo with CCs that entered into service before 2000 having higher costs (due to their inflexible characteristics) relative to other CCs and CTs.
- Oil/gas-fired steam turbines are assumed to offer to sell capacity at a breakeven level considering based on relatively high ($21/kw-month in 2030$) GFCs, higher expected future PPR levels, and their typically poor performance in PFP events.

These capacity offers were set considering the revenue levels that would result in retirements in sustained over a three-year period. Hence, these capacity offers are generally higher than what would be appropriate if we were modeling a single year of revenues.

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24 See *Offers Summary.xlsx* file in the *Inputs* folder for our assumptions regarding offers from existing resources.

25 Unless noted otherwise, all offers, prices and revenues in this section are shown in 2030$.

Capacity Imports

We included capacity supply from the following neighboring markets:[26]

- New York – Consistent with recent FCA outcomes, we included up to 750 MW of imports from New York. We assumed that imports from New York are price sensitive, and that the offer levels depend on: (a) the slope of the demand curve in the New York Control Area ("NYCA"), and (b) the capacity prices in NYCA. We considered 3 scenarios (with equal probability weights) for the surplus/ capacity prices in NYCA:
  - *Large Surplus* - NYCA prices are close to $0/kW-mo. An upward sloping import cost curve rises from $0 based on the slope of the NYCA capacity demand curve.
  - *Moderate Surplus* - NYCA prices are half its Net CONE. The import cost curve rises from this level based on the slope of the NYCA capacity demand curve.
  - *NYISO is at criteria* - NYCA prices at its Net CONE. The import cost curve starts at this level.
- *Hydro Quebec and New Brunswick* – We included imports from Canada (HQ and New Brunswick) over existing as well as potential new transmission ties.
  - *Existing Ties* – We included imports from Canada over existing lines based on actual cleared quantities in FCA-15.
  - *New Transmission Lines* – The Massachusetts utilities have entered into long-term contracts with New England Clean Energy Connect ("NECEC"), which is a 1200 MW HVDC transmissions line. For the purposes of our analysis, we assigned a weight of 80 percent to the scenario where the NECEC is in-service.

New Offshore Wind Resources

Several New England states have set targets to procure offshore wind resources. However, the quantity and timing of entry is uncertain. The target quantities and the timing of the targets have become increasingly aggressive (see Table 1) over the years. Conversely, there have also been delays in entry of offshore wind resources that have already secured contracts with state utilities. We developed three equally weighted scenarios for offshore wind capacity in 2030: [27]

- *Mid* – Assumes offshore wind quantities that are currently targeted by 2030 by Massachusetts, Connecticut and Rhode Island.
- *Low* – Includes only the procurements that are currently underway or complete.
- *High* – Assumes additional procurements similar to recent increases in MA, CT and RI. These states have increased their targets by over 4 GW in the last 4 years (see Table 1).

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[26] See *Offers Summary.xlsx* file in the *Inputs* folder for our assumptions regarding capacity supply offers from neighboring control areas.

[27] See *OSW Solar and ES MW Summary.xlsx* file in the *Inputs* folder for our assumptions (and their data sources) regarding offshore wind capacity (nameplate and qualified) in each scenario.

We estimated the amount of capacity that could be sold in future FCAs using an ELCC curve that reflects the falling capacity value of offshore wind resources as the penetration levels increase.[28] We further assumed that the offshore wind resources will offer into the FCA at the starting price in the MOPR case (consistent with the latest ORTP for offshore wind), and will be price takers in the No MOPR case.

New Energy Storage and Solar Resources

Investments in solar and energy storage ("ES") resources are supported by a variety of state programs such as Renewable Portfolio Standards, storage-specific mandates, and Massachusetts' SMART program and Clean Peak Standard programs. Like offshore wind programs, the state targets for these technologies have grown in recent years. However, the capacity supply from these resources at a given time depends on the technology costs, the pace of development, and the target quantities, which are all uncertain. Indeed, the amount of new utility-scale solar capacity in 2030 varies from less than 2 GW to over 6 GW across the scenarios studied in the Massachusetts' Decarbonization Roadmap study.

We assumed the nameplate capacity in 2030 for solar and ES resources that are interdependent.[29] Specifically, we use the following three solar-target scenarios:

- *Mid* – In this scenario, the subsidized solar capacity is based on the SMART program target for 2030.
- *Low* – The target for solar capacity in this scenario is based on the 2021 CELT report forecast of FCM-PV.
- *High* – The target for solar capacity in this scenario is based on the deployment by 2030 in the '100 percent renewable primary' case of the MA Pathways study.

We use the following three storage-target scenarios:

- *Mid* – The capacity target for subsidized ES resources is based on existing storage-specific state targets, and the estimated capacity that will be supported through SMART and Clean Peak programs.
- *Low* – Assumes a 50 percent shortfall in attaining ES Mid-target.
- *High* – The total ES resources across all the states will be 150 MW storage per 1 GW of ISO-wide peak load.

Figure 9 shows the target capacities (nameplate) for the three solar scenarios and the three ES resources scenarios.

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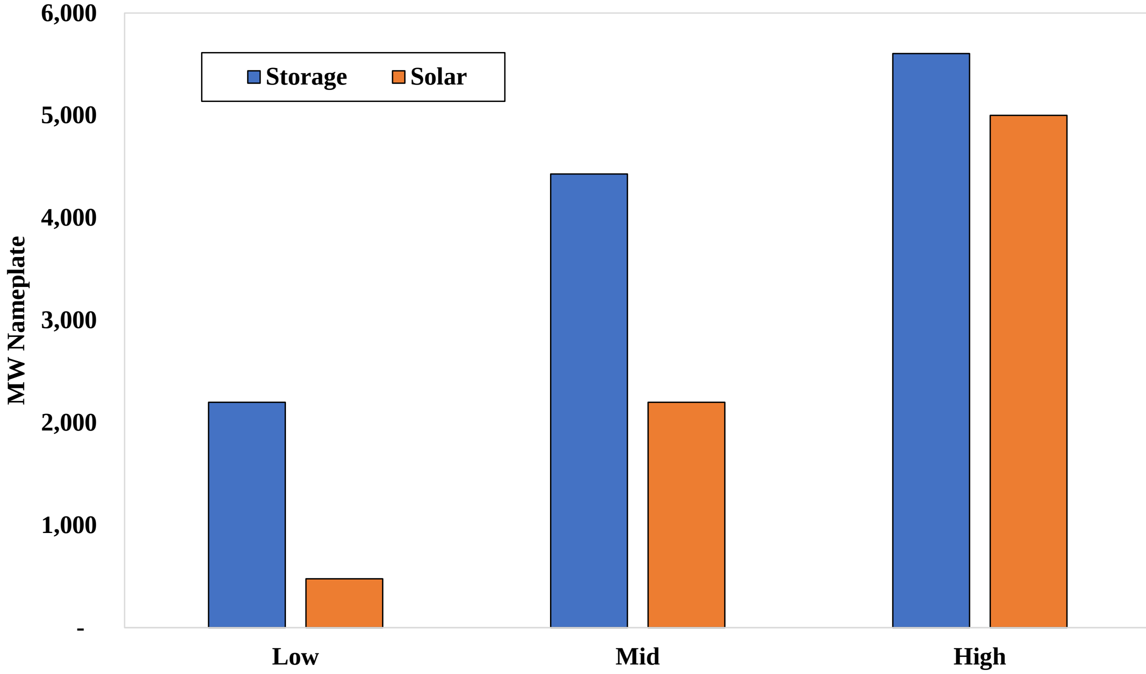
28 The curve we relied on was developed for the New York system, but it considered comparable quantities of intermittent resources. See The Brattle Group's 2020 presentation on Quantitative Analysis of Resource Adequacy Structures.

29 See *OSW Solar and ES MW Summary.xlsx* file in the *Inputs* folder for our assumptions (and their data sources) regarding solar and energy storage resources capacity (nameplate and qualified) in each scenario.

Figure 9: Targets for Solar and Storage Resources (nameplate capacity)



Solar and ES resources can have greater capacity value (quantified using ELCC methods) in combination than individually. Hence, we considered synergies between ES and solar penetration in translating the target capacities into qualified capacity from these resources. We developed ELCC values for solar and storage resources in the above scenarios using data from several regional studies.[30]

Figure 10 shows for each scenario, the total subsidized capacity from solar and ES resources that would be sold in the FCM.

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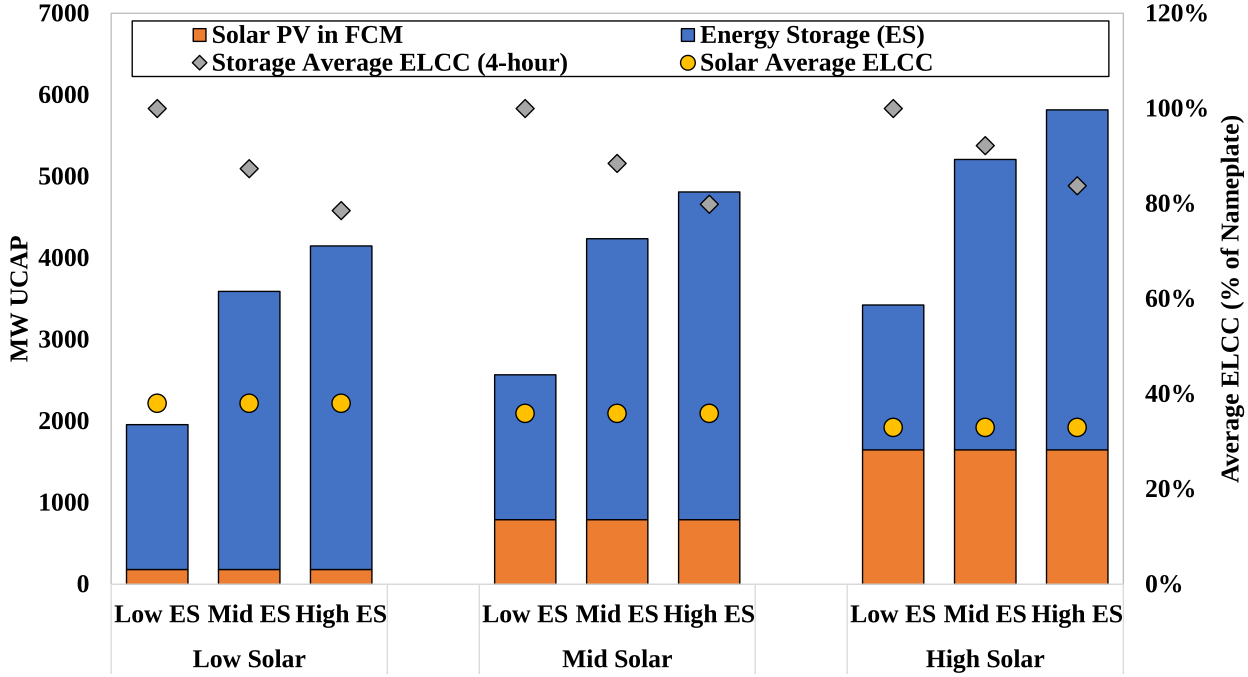
30 The ELCC curve for solar resources was derived from a 2020 Brattle Group study of the New York system. See The Brattle Group's 2020 presentation on *Quantitative Analysis of Resource Adequacy Structures*.

The ELCC of ES resources was adjusted to account for renewable resource penetration based on a 2019 study by NREL for ISO-NE. See NREL's 2019 report on *The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States.*

The slope of ELCC curves for 2-hour and 4-hour storage resources were derived from a 2019 study by GE for the New York system. See GE Energy Consulting's 2019 presentation on Valuing Capacity for Resources with Energy Limitations

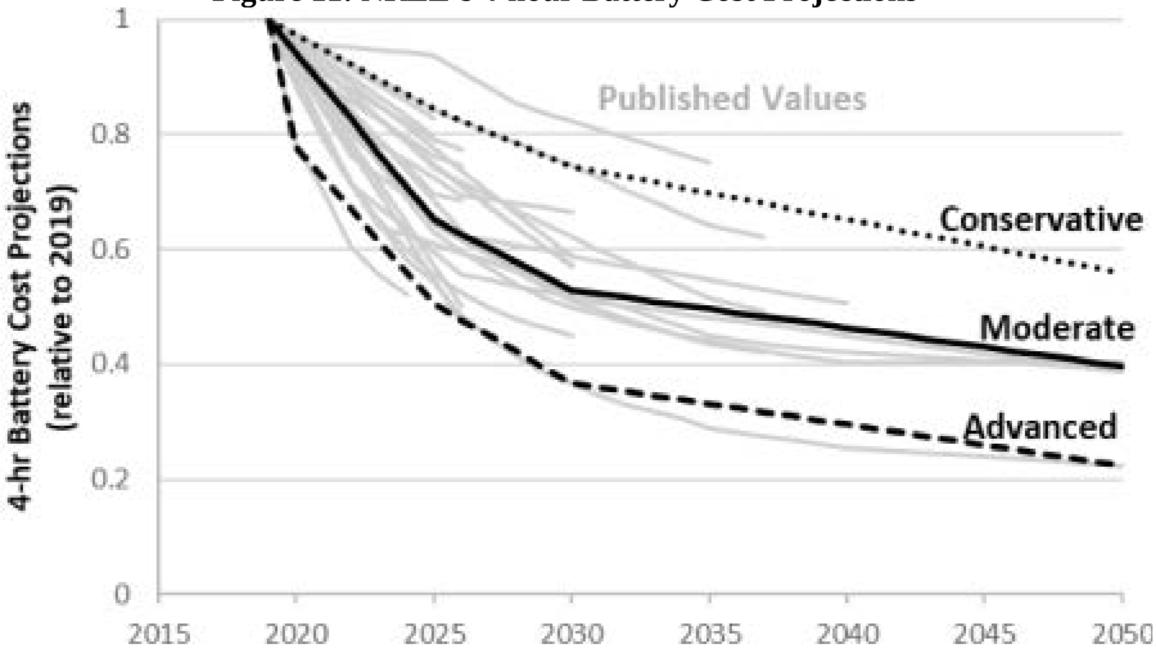
Figure 10: Qualified Capacity from Subsidized Energy Storage and Solar Resources



For determining the solar target capacity in each Monte Carlo realization, we assumed equal weighting of the three solar scenarios described above. Our assumed probability weighting of the ES scenarios depends on the cost of the batteries, which we treat as a stochastic variable in our model. We assumed that the probability of higher ES quantity targets is inversely correlated to storage costs. Battery costs in 2030 are assumed to be a uniform distribution bounded by *Conservative* and *Advanced* cases published by NREL (see Figure 11). Ultimately, we assumed that:

- If the battery costs are in the top third of the distribution (i.e., costs are high), the ES capacity target is equally weighted between low and medium scenarios.
- If the battery costs are in the bottom third of the distribution (i.e., costs are low), the ES capacity target is equally weighted between high and medium scenarios.
- If the battery costs are in the middle third of the distribution (i.e., costs are in the mid-range), the ES capacity target is equally weighted between low, medium and high scenarios.

Figure 11: NREL's 4-hour Battery Cost Projections[31]



Since Class I REC revenues are treated as "in-market" revenue for the purposes of Offer Floor Price calculation, we assume solar resources will be price-takers in both MOPR and No MOPR cases. We assume ES resources are price-takers in the No MOPR case, to the extent they are subsidized, with the possibility of additional merchant entry at higher prices according to the battery cost scenario described above. In the MOPR case, the offer price depends on the battery cost scenario with the average offer prices (before adjusting for ELCC) being:

- For 2-hr units, $2.9/kW-mo in 2030$, which is equal to their ORTP.
- For 4-hr units, $6.40/kW-mo in 2030$, which is a value developed by the IMM's consultants for its FCA-16 new resource reviews.

New Combustion Turbines

We assumed that a new CT will continue to be the reference unit for the capacity demand curve. However, the ability of new fossil-fired resources to be permitted and the availability of sites for building a large number of new CTs is unclear. Hence, we modeled four equally weighted scenarios with varying quantities (2 to 8 CTs or approximately 740MW to 3GW) of feasible new CT build.

In each scenario, we assume that half the new CTs offer their capacity at Net CONE while the other half offer at a slightly higher price of Net CONE + $0.75/kW-mo.

31 See NREL's 2019 report on *The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States.*

6. Reference Unit Revenues

The reference unit receives capacity revenues, revenues from sale of energy and ancillary services ("EAS"), and Pay for Performance ("PFP") revenues. All these revenue streams tend to decline (at varying rates) as the capacity surplus increases. In this subsection, we describe our methodology for estimating the revenue to the reference unit as the various assumptions about supply and demand from the previous subsections combine to produce a Monte Carlo realization-specific capacity surplus.

Capacity Revenues

In each Monte Carlo realization, we determine the capacity revenues to the reference unit using the realization-specific capacity surplus and the capacity demand curve. We determine the demand curve by scaling the MRI curve used in FCA-15 using the iteration-specific Net CONE of the reference unit.

Energy and Ancillary Services Revenues

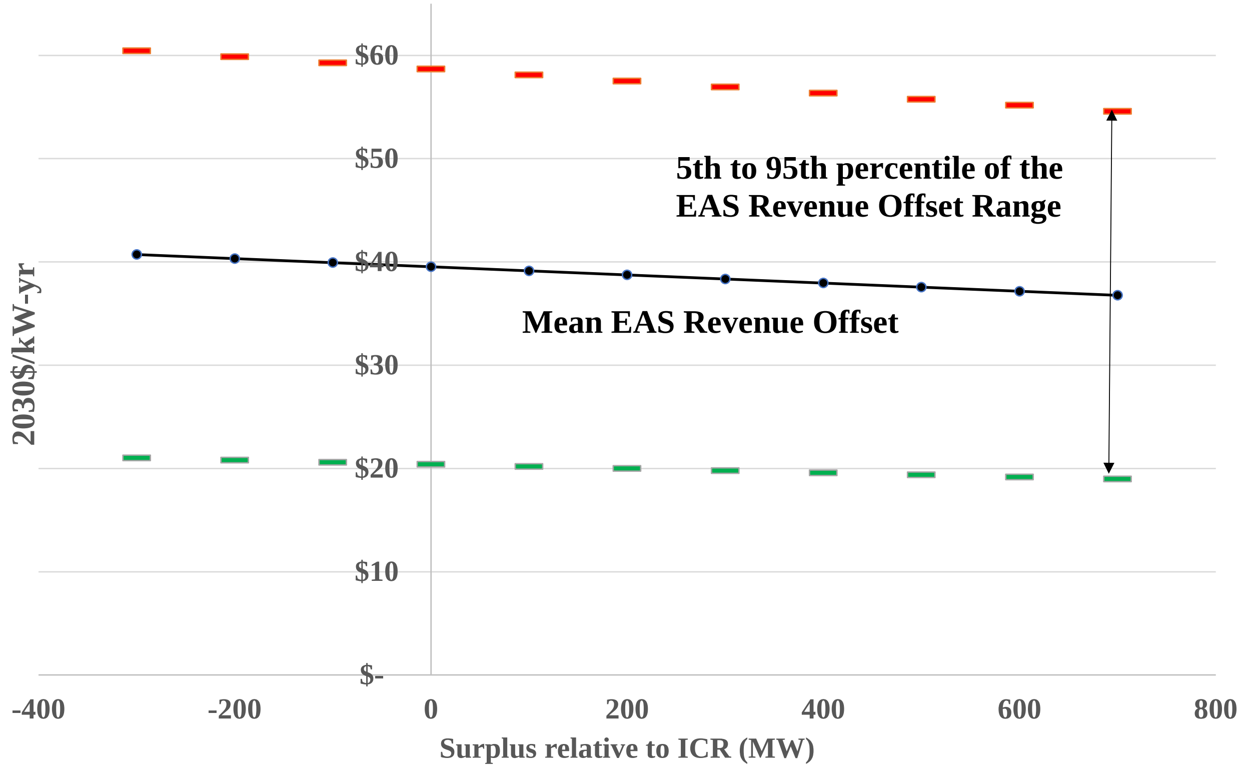
As part of the CONE study, the ISO's consultants estimated the revenues a CT would earn from the sale of Energy and Ancillary Services ("EAS") at criteria using the results of a production cost model and a simplified dispatch model.[32] The consultants also estimated the unit's EAS revenues under historical surplus conditions in its ORTP analysis. We utilized these revenue estimates to develop our model, which estimates EAS revenues of the Reference Unit in each Monte Carlo realization in the following manner:

- EAS revenues are assumed to be a stochastic variable with a mean and standard deviation that decrease linearly as the capacity surplus increases (see Figure 12). We assumed that the revenues are distributed normally.
- This linear relationship is consistent with using: (a) EAS revenues of a new CT at criteria from the CONE Study, and (b) EAS revenues used in the new CT's ORTP which was estimated for a surplus of approximately 600MW (average over 2016/17-2018/19).

Figure 12 shows the assumed relationship between the EAS revenue offset and the capacity surplus. The revenues shown consider prices that do not include the effects of the Reserve Constraint Penalty Factor ("RCPF") during shortage events, which are addressed along with PFP revenues in the next part of this subsection.

[32] The revenue offset discussed in this subsection excludes EAS revenues during shortage events.

Figure 12: Distribution of EAS Revenues at Various Surplus Levels



As noted in IV.A, the revenue in each Monte Carlo realization in our study represents the average of three years of revenue. Accordingly, we estimate the EAS revenue in each Monte Carlo realization as the average of three random draws from the assumed probability distribution of annual EAS revenues for a given surplus level.

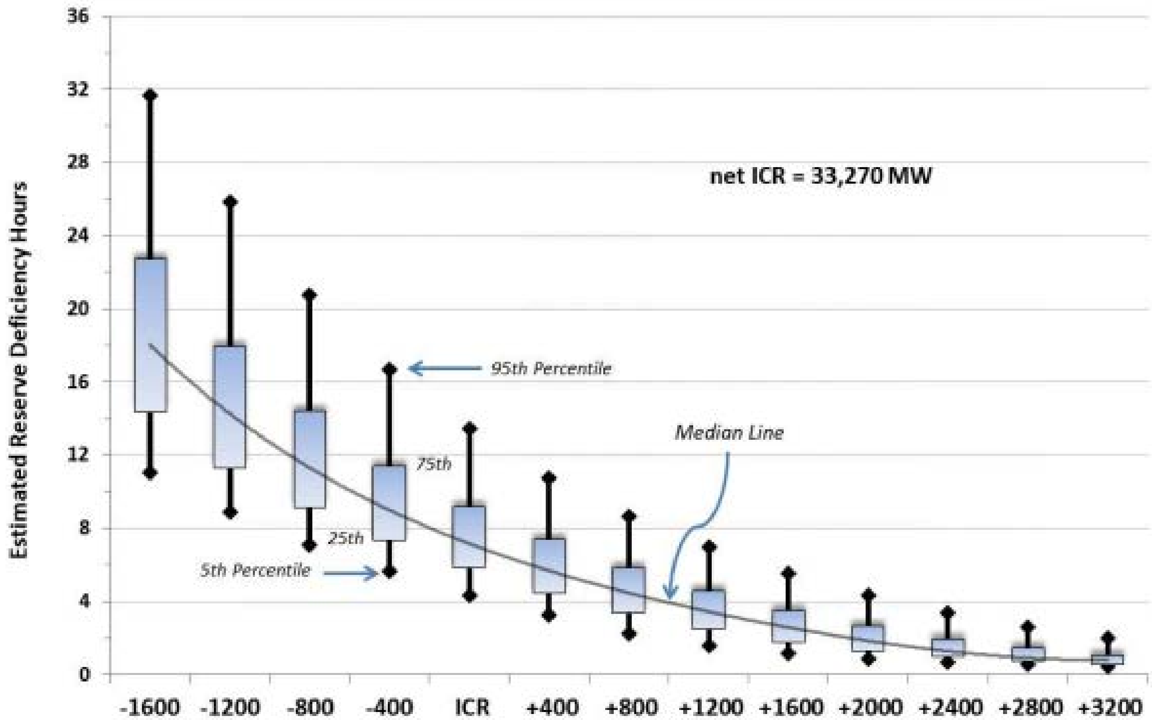
Pay for Performance and Reserve Shortage Revenues

In addition to the EAS revenues discussed in the previous section, the Reference Unit could receive the following streams of revenues during reserve shortage hours: (a) Pay for Performance ("PFP") revenues, when it performs better than the average resource, and (b) additional energy and reserve revenues (i.e., shortage revenues) due to the portion of the LMP that corresponds to the RCPF. We estimated these revenues in each realization using the following parameters:

- The number of reserve shortage hours ("H") in the realization. The distribution of H depends on the capacity surplus.
    - Figure 13 shows the distribution of H as a function of the capacity surplus. We estimate the H in each realization using (a) the capacity surplus in the realization, and (b) the average of three random draws from the distribution for H at that level of surplus.

- We assume that the relationship between H and the capacity surplus is consistent with the results of the ISO's study on *Estimated Hours of System Operating Reserve Deficiencies* for FCA-15.[33,34]

Figure 13: Estimated Hours of System Operating Reserve Deficiencies for 2024/25



- The RCPF. Our assumed value for the RCPF ($1000/MWh) is consistent with the value used in the CONE study.

- The performance of the unit during shortage events ("A") and the average balancing ratio ("Br"). Our assumptions for A and Br are consistent with the values used in the CONE study.

33 The mean H used for our analysis differs from the value used in the CONE study. While the CONE study uses the average H (11.3 hours) from the Capacity Commitment Periods for FCAs 11-15, we use the mean (summer) H (7.9 hours) from the study for only FCA-15. Our choice was driven by the availability of data characterizing the relationship between H and the capacity surplus level. Assuming a higher mean H that is closer to the H from the CONE study would not affect the average PFP revenues, since the PPR value would be lower. Hence, the contribution of PFP revenues to the Net CONE of the reference unit is likely to be similar between the CONE study and our analysis.

34 We assumed that existing capacity would be retained, if necessary, to satisfy a reliability standard of 1-day-in-5-year LOLE. As a result, the shortfall in capacity (relative to the ICR) is limited to approximately negative 610 MW. This assumption bounds the H value, but it does not affect the capacity prices because the maximum price for the FCA is consistent with the capacity surplus level at which the LOLE is 1-day-in-5-years.

- The Performance Payment Rate (“PPR”). We utilized a PPR value that we developed by adjusting the PPR developed for FCA-16 by (a) inflating the PPR to 2030$, and (b) adjusting the resulting value using the ratio of H used in the CONE study and the mean H for FCA-15’s Capacity Commitment Period.[35]

7. Financial Inputs

The estimation of COE and COD relies a number of financial assumptions. These include CAPM parameters (CAPM betas, risk free rate, market risk premium), cost of debt and capital structure for merchant and regulated entities, bond yields by rating, tax rates, etc. To the extent applicable, we utilized data from the CONE study for many of these parameters. We have posted supplemental spreadsheets that detail the values that we used for these parameters and the sources for each of them.[36]

35 The ISO determines the PPR as a function of the Gross CONE of the reference unit. We hold the PPR constant when determining the WACC in the No MOPR case and, modify the PPR in the No MOPR case after finalizing the WACC parameters.

36 See *Financial Assumptions.xlsx* file in the *Inputs* folder.

V. RESULTS AND CONCLUSIONS

Using the modeling approach discussed in Section III and the inputs described in Section IV, we estimated how changes in the MOPR rules would be expected to affect financial risk for a merchant investor. This section provides an overview of the results of our analysis, including the estimated effects on the cost of capital used in setting the capacity demand curve. Subsection A provides detailed results.[37] The overall conclusions of our analysis are provided in subsection B.

A. Results

In this subsection, we summarize various intermediate modeling results that demonstrate how we estimate the impact of MOPR elimination on the ATWACC and Net CONE of the reference unit. We discuss the following results from our analysis in the rest of this subsection:

- Distribution of revenues under long-term equilibrium conditions in the MOPR and No MOPR cases *before* WACC adjustment
- Initial estimates for COE and COD in the No MOPR case
- Iterations to determine final COE and COD at the default leverage ratio
- Optimal leverage ratio and estimated final WACC for the No MOPR case
- Estimated Net CONE in the No MOPR case

1. Distribution of revenues in the MOPR and No MOPR cases before WACC adjustment

Figure 14 shows the distribution of revenues to the reference unit across 2000 Monte Carlo realizations in the MOPR and No MOPR cases under long-term equilibrium conditions. The chart shows the percentage of the total realizations on the horizontal axis where the revenue was higher than the value shown on the vertical axis. The figure also shows (a) the standard deviation of the distribution in each case, (b) the portion of the distribution where the revenues correspond to a B+/BB- rating (i.e., DSCR is between 1.27 and 1.53) in the MOPR case (labeled as Rating Case range), (c) the Rating Case revenues for the No MOPR case, and (d) the Base Case (i.e., average) revenues in the MOPR and No MOPR cases.

As discussed in III.B, given the surplus supply in both MOPR and No MOPR cases, the average revenue does not equal the Gross CONE of the reference unit in both cases. Hence, to study the impact of MOPR elimination at long-term equilibrium, we adjusted the supply stack by removing capacity from higher-cost existing resource. The amount of existing capacity that we removed is approximately (a) 1,150 MW in the MOPR case, and (b) 4,200 MW in the No MOPR

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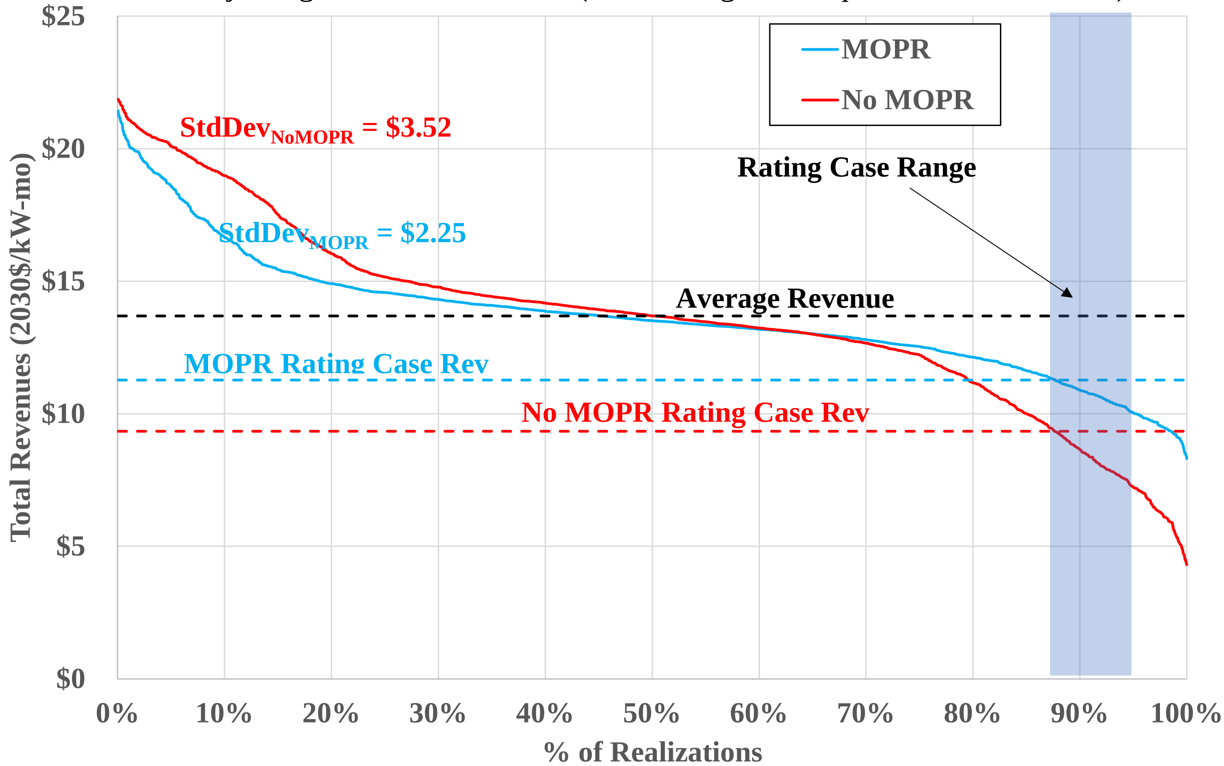
37 In addition to the results discussed in this report, we posted files containing detailed model results. These include realization-level data on supply and demand variables, clearing prices, total revenues and various other tables that summarize/ aggregate these data. See *Outputs* folder.

case. The following figure shows the distribution of revenues after these supply adjustments are made.[38] The figure also shows the average revenue and the Rating Case revenues (along with the Rating Case range) for each case.

Figure 14: Distribution of Revenues to Reference Unit with and without MOPR

Before Adjusting WACC Parameters (under Long-term Equilibrium Conditions)



Several observations can be drawn from the above figure:

- Consistent with the long-term equilibrium conditions, the average revenue in both the MOPR and No MOPR cases equals the Gross CONE.
- The distribution of revenues in the MOPR case is flatter than the revenue distribution in the No MOPR case, i.e., the standard deviation of the revenues in the No MOPR case is (by 56 percent) higher than that in the MOPR case.
- The likelihood of low revenues (i.e., higher probability of downside scenarios) is higher in the No MOPR case. In specific, the average revenue in the Rating Case range in the No MOPR case is 17 percent lower than in the MOPR case. The Rating Case range, i.e.,

38 The capacity that we removed was mostly from inflexible combined cycle units. We assumed that combined cycle units installed before 2000 will have higher offers than other combined cycle units. This is because these units are among the existing fleet's least flexible units and are likely to incur substantial PFP penalties given their likely worse-than-average availability, particularly in a high renewable penetration scenario. For the purpose of our analysis, we assumed that all steam turbines are retired or no longer sell capacity due to high GFCs, higher PPR, and poor performance in PFP events. See *Offers Summary.xlsx* file in the *Inputs* folder for our assumptions regarding offers from existing resources.

the portion of the distribution corresponding to a B+/BB- rating under status quo, falls between the 9th to 16th percentile of the revenue distribution.[39]

The above characteristics of the revenue distribution affect the COE and COD in the No MOPR case, which we discuss in the next subsection.

2. *Initial Estimates of Cost of Equity and Cost of Debt*

Cost of Equity

Based on the results shown in Figure 14, the higher standard deviation of revenues in the No MOPR case ($3.52/kW-month in 2030$) correspond to a higher COE relative to the MOPR case ($2.25/kW-month in 2030$). We estimate the increase in COE in the No MOPR case in the following manner:[40, 41]

Increase in COE without MOPR = Std Dev(RevMOPR)/ Std Dev(RevNoMOPR) x Power Market Risk component of COE = 1.69%

Given the 13 percent COE assumed for the MOPR case, our initial estimate of the COE in the No MOPR case is 14.69 percent.

Cost of Debt

The average revenue in the Rating Case range, i.e., the 9th and 16th percentile of the revenue distribution, in the MOPR case is $11.27/kW-mo (2030$).[42] The average revenue in the same portion of distribution in the No MOPR case is 17 percent lower, which corresponds to a DSCR of 0.85. Consequently, we estimate an initial COD of 10.22 percent in the MOPR case, based on our assumed relationship between Rating Case DSCRs and the COD.[43]

Table 4 shows the derivation of the DSCRs in the base case (i.e., the case with expected revenues), the Rating Case DSCRs in the MOPR and No MOPR cases.

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39 See IIIA.B.2 for discussion of methodology for estimating COD.

40 See discussion in III.B.1.

41 Unless noted otherwise, all prices and revenues in this section are shown in 2030$.

42 The B+/BB- rating under status quo, i.e., the Rating Case range, corresponds to the 9th to 16th percentile of the revenue distribution. See IIIA.B.2 for discussion of methodology for estimating COD.

43 See Figure 6.

Table 4: DSCRs in Base and Rating Case

2030$/kW-mo	Notes	Base	Rating Case MOPR	Rating Case No MOPR
Total Revenues	[1]	$ 13.7	$ 10.6	$ 8.8
Fixed costs	[2]	$ 5.3	$ 6.0	$ 6.0
Taxes	[3]	$ 1.0	$ 0.0	$ -
Net Cash Flow	[4] = [1] - [2] - [3]	$ 7.4	$ 4.6	$ 2.8
Debt Service	[5]	$ 3.3	$ 3.3	$ 3.3
DSCR	[4]/[5]	2.25	1.41	0.85

[1] Includes Capacity, PFP, scarcity and EAS revenues. All revenues derated by 6% to account for lower availability and EAS revenues derated by 2.5% to account for higher heat rate
[2] Fixed O&M in Rating Case increased by 12% per guidance from S&P and Fitch (relative to base case) to reflect performance stress
[3] Federal and State income taxes

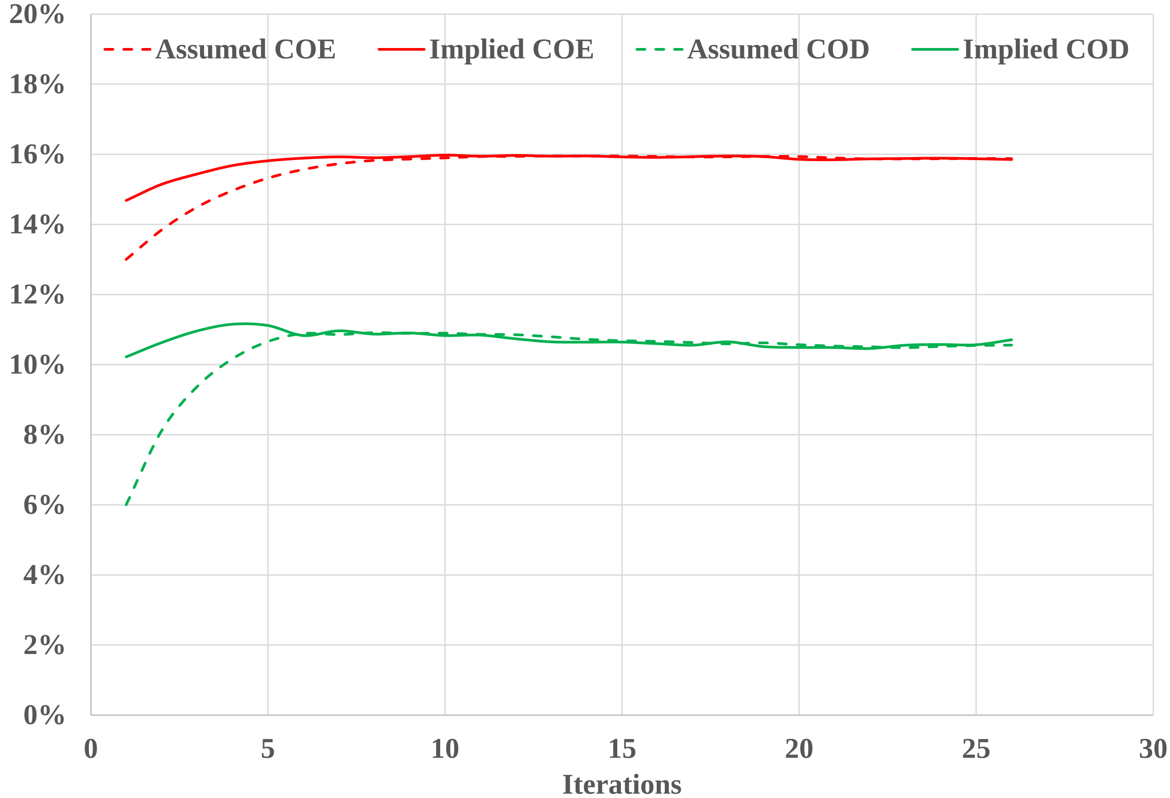
3. *Iterations to determine COE and COD at the default debt ratio*

The above estimates for COE and COD produces an initial ATWACC of 10.72 percent (assuming the default 55% debt ratio used in the CONE study). However, the distribution of revenues shown in Figure 14 is based on a capacity demand curve which utilizes a Net CONE that is based on 8.26 percent ATWACC. Similarly, the offers from new CTs and merchant energy storage are also based on an ATWACC of 8.26 percent. This highlights an inconsistency between:

- (a) the COE and COD values that we assumed to estimate the revenue distribution in the No MOPR case, and
- (b) the COE and COD values that are implied by the revenue distribution in the No MOPR case.

As discussed in III.B.3, we address this inconsistency through iterations in which we gradually changing the assumed COE and COD values such that the difference between (a) and (b) above is reduced. Figure 15 shows the results of these iterations for the debt ratio of 55%. The results indicate that the assumed and implied values of COE and COD converge reasonably well after 10 iterations. Ultimately, we estimate final COE and COD values at a debt ratio of 55 percent as 15.88 percent and 10.56 percent.

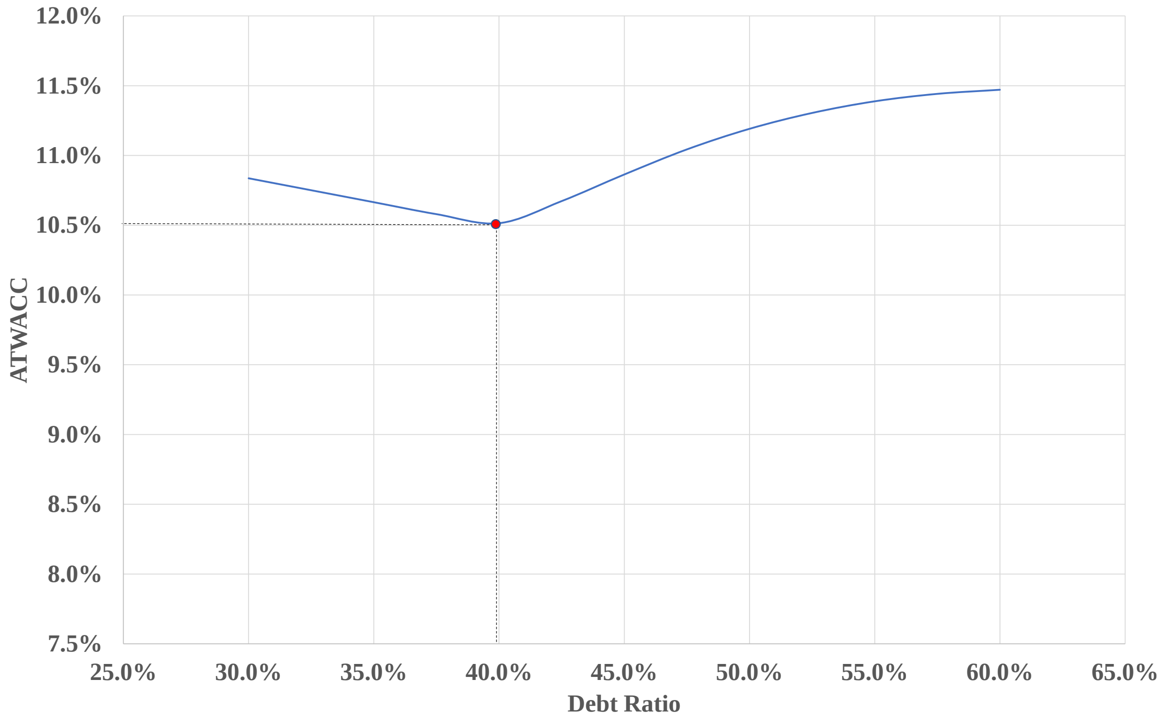
Figure 15: Iterations to determine COE and COD in No MOPR Case
At 55 percent debt ratio



4. Estimated Optimal Leverage Ratio and Final ATWACC

As discussed in III.B, we evaluate whether the overall ATWACC can be lowered by adjusting the debt ratio in the No MOPR case. Figure 16 shows the results of this evaluation. For each level of assumed debt ratio, the figure shows the estimated ATWACC in the No MOPR case.

Figure 16: Change in ATWACC with Leverage



Our analysis indicates that the optimal debt ratio in the No MOPR case is approximately 40 percent. At this debt ratio:

- The COD in the No MOPR case is reduced to 5.12 percent (compared to the COD at a 55 percent debt ratio). This is because the Rating Case DSCR improved from 0.82 at a 55 percent debt ratio to 1.59 at a 40 percent debt ratio.
- The COE in the No MOPR case also declines to 15.03 percent. This is because the volatility of returns to equity holders is lower at a 40 percent debt ratio relative to the volatility at a 55 percent debt ratio.[44]

Overall, we estimate the ATWACC in the No MOPR case to be 10.51 percent. This estimate considers the effects of a lower (40 percent) debt ratio, including the resulting decrease in the COE and COD (which reduce the ATWACC) and the associated increase in the weight of the COE (which increases the ATWACC).

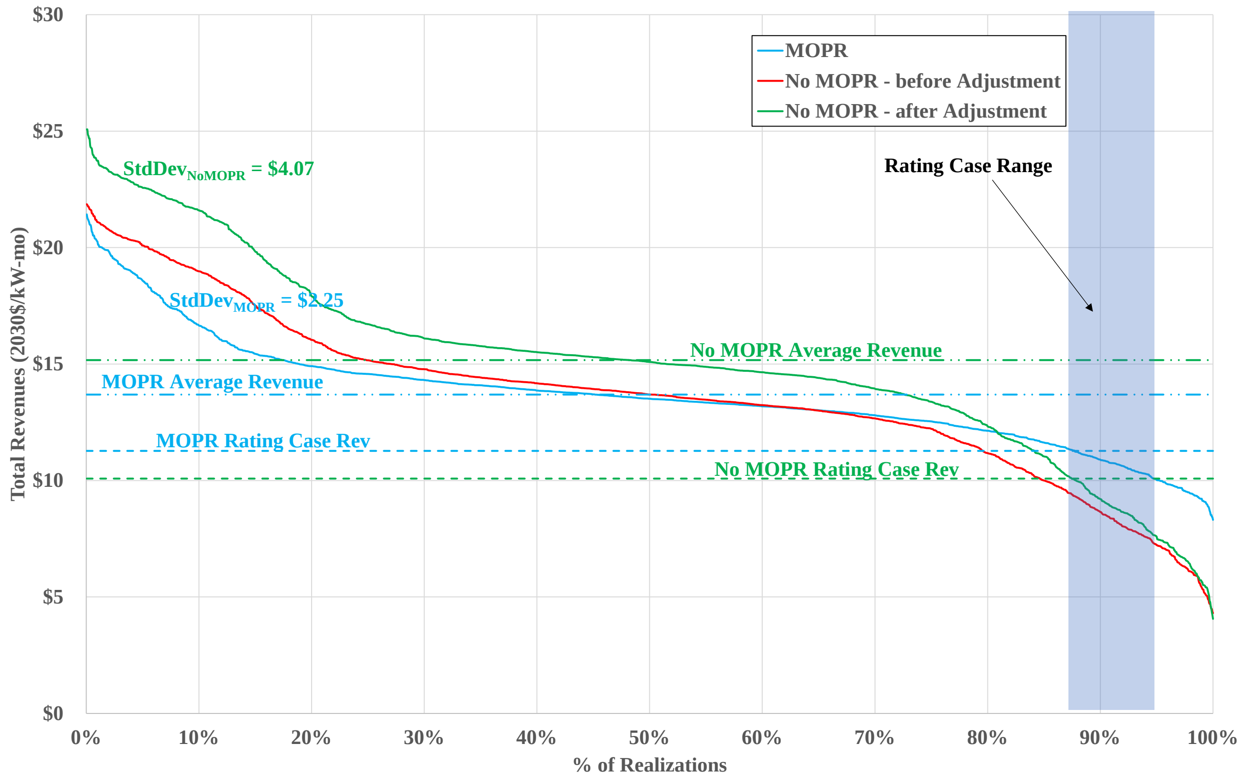
The higher final ATWACC in the No MOPR case affects the capacity supply and demand curves, which affects the distribution of revenues to the reference unit. The following figure shows the distribution of revenues to the reference unit for the following cases: (a) MOPR case, (b) No MOPR case before WACC adjustment, and (c) No MOPR case after WACC adjustment.

[44] In general, Return to equity = (Free Cash Flow – Debt payment)/ Equity Value. Hence, as the equity value decreases (i.e., the denominator decreases), all else being equal, the volatility of the returns to equity holders increases. This increase in volatility at higher leverage levels is partially offset by the reduction in COE as some of the default risk shifts away from equity holders (to debt holders).

The Figure also shows the risk metrics of interest (standard deviations and Rating Case revenues) for estimating the COE and COD.

Figure 17: Distribution of Revenues to Reference Unit

MOPR Case, and No MOPR case before and after WACC Adjustment



As shown in the above figure, the revenue in the No MOPR case even after the WACC adjustment is still more volatile (i.e., has a higher standard deviation) than in the MOPR case, and there continues to be a higher downside risk to the merchant reference unit. Nonetheless, the average revenue in the No MOPR case after WACC adjustment is 11 percent higher than in the MOPR case.

5. Estimating Net CONE and PPR in the No MOPR Case

We estimated the Net CONE in the No MOPR case by incorporating the above WACC parameters into the ISO's discounted cash flow model. We determined that if MOPR is eliminated, the Net CONE needs be increased to $8.66/kW-mo in 2025$ which is 16 percent higher than the Net CONE of $7.47/kW-mo under status quo.

Updating the WACC parameters to calculate the Net CONE would also involve developing a new estimate for the PPR. This is because the ISO sets the PPR such that if the reference unit's performance is zero during shortage hours, its PFP penalties would fully offset its capacity revenues.[45] Hence, the PPR is a function of the Net CONE and should increase as the Net CONE increases. Accordingly, we updated the PPR to $10,846/MWh (compared to $9,337/MWh under status quo) to reflect the higher Net CONE in the No MOPR case.[46]

B. Conclusions

We developed a model that evaluated the impact of eliminating MOPR on the financial risk to investors. We find that:

- There is a considerable difference in the volatility of revenues to the reference unit with and without MOPR.
- The ATWACC without MOPR should be increased to 10.51 percent (from 8.26 percent under status quo) to compensate investors for the higher risk in the No MOPR case.
- This increase in ATWACC translates into a Net CONE of $8.66/kW-month (or 16 percent higher than the current value of $7.47/kW-month in 2025$). In addition, the PPR should be increased to $10,846/MWh from $9,337/MWh, to reflect the higher Net CONE of the reference unit.

45 This condition is characterized by the following relationship: PPR = (Gross CONE – EAS revenue) / (H x A). See ISO's September 2013 memo on *FCM Performance Incentives – Performance Payment Rate*.

46 Although the estimated final PPR in the No MOPR case is higher, we use the same PPR value for both MOPR and No MOPR cases in determining the impact of MOPR elimination on WACC. This simplification is unlikely to have a significant impact on the final estimate for Net CONE in the No MOPR case.