Qualitative Analysis of Resource Adequacy Structures for New York

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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.

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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 qualitative 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

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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.

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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

[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

[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:

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

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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