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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 19-E-0530 - Proceeding on Motion of the Commission to Consider Resource Adequacy Matters.

COMMENTS OF NRG ENERGY, INC.

By notice issued on August 8, 2019 the New York Public Service Commission ("Commission") "commenced a proceeding to examine how to reconcile resource adequacy programs and the State's renewable energy and environmental emission reduction goals" and invited written comments related to the Commission's resource adequacy inquiry and other related matters (the "Notice"). With support from the attached Affidavit of Robert B. Stoddard (see Attachment A), NRG Energy, Inc. ("NRG") provides the following comments and recommendations that would allow the State to maintain a reliable electric system while advancing its environmental goals. Reflecting the State's policy goals in the market structure is a laudable goal, but is reasonable only when considering market design in a holistic manner. While the State has established its environmental goals, the Commission need not jeopardize the reliability benefits and market-driven investment signals provided by the capacity market.

I. Introduction

NRG's feedback is based on our experience in not just the NYISO market, but as an active participant with substantial investments in markets across the country. Any suggestions to replace the NYISO capacity construct to accommodate environmental goals are simply misplaced. The Notice suggests that the NYISO capacity construct is insufficient because "it fails to recognize and provide compensation for many important factors, such as environmental and local reliability benefits."[1] However, the goal of resource adequacy is to ensure the State has enough reliability, which is and should remain separate and apart from environmental goals.

Capacity itself does not result in the production of carbon emissions, rather the production of energy from fossil fuels does. Capacity is simply the ability of a generator to produce energy at times when its most critical. A binding constraint at the relevant point of the market structure (i.e., pricing carbon in the market) would advance the State's environmental policy goals, but to build in carbon as a constraint in each and every facet of the market risks duplication and higher costs. And, on the more extreme side, to eliminate the capacity market would jeopardize the reliability of the bulk power system that New York has relied upon since its inception.

The concern that the capacity market works at logger heads with a low-carbon energy market is unwarranted. The current capacity market has successfully maintained reliability in the State and as recognized by Mr. Stoddard, has "allowed for a rapid evolution of the power grid."[2] As further discussed by Mr. Stoddard, 23.6 GWs of coal-fired generation has already retired in the three northeast RTO/ISOs since 2013, and another 5.9 GWs have announced retirements.[3] Also as Mr. Stoddard points out, "[i]n 2000 coal-fired generation accounted for 11 percent of New York's installed capacity, while today it accounts for 2 percent of installed capacity."[4]

If there is concern that the capacity market's design disadvantages, or may in the future disadvantage, clean energy resources in favor of fossil resources, and the State wishes to further

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[1] Case 19-E-0530, Proceeding on Motion of the Commission to Consider Resource Adequacy Matters, "Order Instituting Proceeding and Soliciting Comments," (Aug. 8, 2019) ("Order").
[2] Stoddard Affidavit at 13.
[3] *Id.* at 13.
[4] *Id.* at 13.

align its competitive electric market with its environmental goals, the appropriate construct for clean energy procurement should be the development of a transparent market price for all clean energy resources. One such possibility is to adopt a forward clean energy market. In a nutshell, the framework is more robust and durable than a renewable portfolio standard and is technology and fuel agnostic, while providing market-based signals and consumer benefits that align with the State's environmental goals. This forward clean energy market would be in addition to the NYISO's energy, capacity and ancillary service markets. The market would compensate environmental attributes while permitting the capacity market to retain its role to ensure resource adequacy. Such an approach would avoid eroding the competitive market structure by making out-of-market payments to specific generators. Some of the benefits of such an approach are as follows:

- Leads to faster and cheaper decarbonization than alternatives;
- Increases competition and distributes risk by expanding the number of buyers and sellers;
- Provides a more level playing field between existing and new resources who provide the carbon free energy;
- Sends a stronger signal to developers to site projects where energy and capacity are most valuable; and
- Avoids conflict between state and federal policymakers by using a non-discriminatory procurement to achiever State goals that is compatible with ISO/RTO markets.

The forward clean energy market ("FCEM") concept is discussed more comprehensively herein (and is attached as Attachment B), but if the Commission is not inclined to support the adoption of such a market, there are other incremental approaches the Commission could support to further the State's environmental goals while maintaining the reliability of competitive markets and the capacity market which are discussed below.

II. Background on NRG

NRG has approximately 23,000 MW of generation resources throughout the U.S. – and is one of the nation's largest competitive retail energy suppliers, with over 3.5 million retail customers. NRG is an active participant in the New York markets, with conventional generation, retail energy services, and a distributed energy management platform which has offices in Buffalo, New York. NRG has approximately 2,900 MW of existing natural-gas and oil-fired generation in New York and is developing both natural gas and energy storage projects within the State. NRG has approximately 350 employees in the State of New York. NRG is leading a customer-driven change in the U.S. energy industry by delivering cleaner and smarter energy choices. A Fortune 500 company, we create value through reliable and efficient conventional generation while driving innovation in the development of storage projects, carbon capture technology and customer-centric energy solutions. NRG is committed to lowering the carbon intensity of electricity production, as well as increasing the deployment of clean generation technologies. In September 2019, NRG announced its commitment to reducing its greenhouse gas emissions by 50% by 2025 and achieving net-zero emissions by 2050.[5]

III. Success of NYISO Capacity Market

NRG recognizes the challenge before the State to significantly reduce emissions of greenhouse gases in the electric sector, while maintaining reliability. The NYISO's capacity market design originated in the 1990s and is responsible for New York having maintained sufficient reserves to meet forecasted loads for nearly 20 years. The capacity market has fostered a fuel diverse resource mix that has successfully maintained New York's reliability through extreme weather events. The market is intended to send price signals to maintain reliability by incenting investment, reinvestment, and retirement, while providing resources the "missing money" relative to revenues from other electricity markets to remain in operation. The Independent Market Monitoring Unit has consistently confirmed that the NYISO capacity market is working well to serve its goals,

[5] https://www.nrg.com/about/newsroom/2019/38151.html.

stating that "[t]he capacity market continues to be an essential element of the NYISO electricity markets, providing economic signals needed to facilitate market-based investment to satisfy the state's planning requirements."[6] As Mr. Stoddard recognizes, the NYISO capacity market has admirably performed the core role of ensuring that resources being paid to be available are, in fact, operating when needed.[7]

Other ISOs with capacity markets have also successfully maintained reliability since the implementation of their capacity markets. As Mr. Stoddard notes, PJM's capacity market has successfully maintained resource adequacy to support reliable grid operations across PJM. "This success came during a period of rapid transition to the PJM generation fleet. . . . In the last three years, [PJM has] seen 8,081 MW of retirements and 22,818 [MW] of new generation."[8] As another example, ISO-NE's most recent state of the market report stated that "[o]verall, the [Forward Capacity Market] has achieved its design objectives of attracting new efficient resources, maintaining existing resources and encouraging the retirement of less efficient resources."[9]

The success of the eastern ISO capacity markets can be compared to the experience in California, which does not have a capacity market but for over a decade, has relied upon the California Public Utilities Commission's ("CPUC") Resource Adequacy program to ensure reliability and to set rates for suppliers of capacity. Question 5 of the Notice asks whether New York should consider alternative approaches to ensure the procurement of generation is aligned with the State policy goals and specifically asks whether an approach similar to that used by California should be considered. As Mr. Stoddard concludes, "[r]esource adequacy in California is an

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[6] *See, e.g.,* Potomac Economics, "2018 State of the Market Report for the New York ISO Markets," at vii (2019) *available at: https://www.nyiso.com/documents/20142/2223763/2018-State-of-the-Market-Report.pdf/b5bd2213-9fe2-b0e7-a422-d4071b3d014b*.
[7] Stoddard Affidavit at 5-6.
[8] *Id.* at 24.
[9] *See* ISO New England, Inc., Internal Market Monitor, "2018 Annual Markets Report" at 19 (2019) *available at:* https://www.iso-ne.com/static-assets/documents/2019/05/2018-annual-markets-report.pdf.

exemplar—of what New York ought *not* to do. The California model is severely broken in many regards."[10]

With California's dramatic increase in renewable resources, demand response and energy efficiency, CAISO grid operators are now more reliant upon imports during peak periods, and have become more dependent on out-of-market mechanisms to ensure reliability, which has resulted in more volatile energy costs for consumers. Historical reserve margins in California, often in excess of 30 percent, have masked the flaws in California's resource adequacy program, but as conventional generators have retired, the reserve margins are plummeting and these flaws are now being unmasked. The market has tightened, and California resource adequacy prices have increased, particularly for resources in local reliability zones and those with flexible ramping attributes which are important for integrating renewables. Across this same timeframe, New York capacity prices have remained relatively stable. In recent years, CAISO has provided out-of-market support to approximately 10% of its local generating capacity. More recently, the CPUC has recognized the potential for a capacity shortfall as early as 2021 and has begun to take steps to address it. On October 21, 2019, the CPUC issued a revised proposed decision recommending (i) that the State Water Resources Control Board extend the once-through-cooling ("OTC") retirement deadline for 3,750 MW of generation from one to three years and (ii) that in addition to the OTC retirement extensions, requires additional procurement of system-level resource adequacy capacity of 4,000 MW to come on-line between August 1, 2021 to August 1, 2023.[11] Further, California has struggled with numerous additional issues in introducing large amounts of renewable energy to its challenged markets, including, but not limited to the following:

- Private investment leaving the market due to the lack of regulatory stability and non-

[10] Stoddard Affidavit at 41.

[11] "Decision Requiring Electric System Reliability Procurement for 2021-2023," Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements," Proposed Decision of ALJ Fitch, Rulemaking R. 16-02-007 (Oct. 21, 2019).

existent longer horizon price signals;

- Large centralized generation stations in regional load pockets retiring, causing voltage stability concerns with metropolitan areas becoming more vulnerable to reliability events, such as wildfires and transmission congestion;
- Increased reliance on out-of-state imports and challenges when these imports do not "show up" due to higher prices in neighboring areas, new difficulties in accurately forecasting supply/demand balancing needs, especially around transmission line outages and seasonal plant maintenance schedules;
- Large generation retirements result in remaining capacity being provided from a fleet of smaller facilities that do not have the economies of scale of the larger facilities and overall prices increase; and
- Demand response and energy efficiency are shoehorned into markets and market rules not suited for them and the market dynamics to incent such generation are not always present;

While there are lessons to be learned from the transition of the California grid, the lack of a centralized capacity platform in California is anything but "golden". The lessons and challenges mentioned above are items to consider in undertaking an approach to adapt the New York market.

IV. Alternative Approaches that Optimize the Benefits of Competitive Markets

On top of New York's existing environmental standards, the Climate Leadership and Community Protection Act, signed into law July 2019 ("CLCPA"), commits New York to reaching net zero greenhouse gas emissions by reducing emissions by 70% by 2030 and using only carbon-free sources of energy to generate electricity by 2040. Historically, the NYISO market has successfully attracted and obtained the resources it needs with its capacity market, but it is a new day when the State effectively outlaws carbon emissions within the investment horizon of new energy infrastructure. While the existing markets work well, they need to evolve to meet the new environmental climate.

With these aggressive environmental goals, New York can learn from California's experience trying to maintain resource adequacy in a renewable rich environment. California's heavy reliance on renewable resources, demand response, energy efficiency and imports created a significant need for flexible and ramping resources and as discussed above, California has struggled with an increased reliance on out-of-market contracts to fill reliability shortfalls. To address these challenges, a holistic, non-discriminatory market design is needed. In considering the best path forward, the State must contemplate how the power market can still attract and retain resources necessary to maintain reliability while balancing the burden of customer costs associated with the CLCPA. There are ways to achieve the State's new environmental objectives, while maintaining the competitive market and reliability.

NRG has been a vocal advocate in favor of competitive markets and against out-of-market subsidies. Out-of-market actions distort market signals and increase costs to consumers. For example, it is estimated that over the 12-year duration of New York's Zero Emission Credit program, which provides subsidies to existing in-state nuclear resources, New York ratepayers will be forced to pay approximately $7.6 billion in subsidies.[12] To take steps to eliminate the capacity market and enter into a system relying upon bilateral contracts, will undoubtedly lead to more out-of-market actions like seen in California. Such an approach is simply not prudent for customers or investment.

Competitive markets drive innovation and incent investments while lowering risks to end-use consumers. Working within a competitive market framework to meet emerging State policy needs will not only protect system reliability but also ensure that the resources that meet those goals and provide economic energy are incented and rewarded for the services they provide. As Mr. Stoddard notes, "markets have already delivered substantial changes in the mix of resources in New York. These markets are the foundation for further changes and refinements that will better enable a rapid yet cost-effective move towards cleaner resources, consistent with [New York's

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[12] Petition for Writ of Certiorari at 10-11, *Elec. Power Supply Ass'n, et al. v. Rhodes, et al.*, 139 S. Ct. 1547 (No. 18-868). https://statepowerproject.files.wordpress.com/2019/01/zec-epsa-petitionforwritofcertiorari-2nd-circuit-010719.pdf.

Climate Leadership and Community Protection Act]."[13]

NRG recognizes that the eastern ISOs have not yet adopted a solution to prevent out-of-market subsidies intended to satisfy the State's environmental goals from suppressing capacity market prices. The issue is under consideration by the Federal Energy Regulatory Commission ("FERC") in the pending PJM capacity docket.[14] In the initial order in that docket, FERC found that it had "become necessary to address the price suppressive impact of resources receiving out-of-market support."[15] Specifically, FERC held that PJM's Tariff was unjust and unreasonable because:[16]

> It fails to protect the integrity of competition in the wholesale capacity market against unreasonable price distortions and cost shifts caused by out-of-market support to keep existing uneconomic resources in operation, or to support the uneconomic entry of new resources, regardless of the generation type or quantity of the resources supported by such out-of-market support. The resulting price distortions compromise the capacity market's integrity. In addition, these price distortions create significant uncertainty, which may further compromise the market, because investors cannot predict whether their capital will be competing against resources that are offering into the market based on actual costs or on state subsidies.

FERC has not yet ruled on the PJM proposal to address the impacts of out-of-market subsidies on the capacity market. If New York were to eliminate its capacity markets as a reaction to the PJM docket out of fear that subsidized resources in New York may be subject to a rule that applies a higher price floor and decreases their chances of clearing and receiving any capacity revenue, such action would be akin to throwing out the baby with the bath water. *First*, as reflected in other jurisdictions new market structures must be implemented to ensure adequate resources are available and even still those jurisdictions, like California, face persistent shortfalls in future generation projections. *Second*, reflecting environmental attributes in the market need not rely on

[13] Stoddard Affidavit at 21.
[14] *See* FERC Dockets EL16-49-000, ER18-1314 and EL18-178 (consolidated).
[15] *Calpine Corp. v. PJM Interconnection, L.L.C.,* 163 FERC 61,236 at P 5 (June 2018).
[16] *Id.* at P 150.

capacity markets exclusively. There are many competitive mechanisms that can be considered to achieve the balance between implementing State goals, maintaining reliability and retaining and incenting economic generation. But as Mr. Stoddard recognizes, "[a]s New York transitions to a low-carbon economy, capacity markets will continue to serve a vital role of ensuring grid reliability."[17]

A. Economy Wide Carbon Pricing

Economy wide carbon pricing would be the optimal approach to reflect the cost of carbon reductions across all sectors of the economy. As recognized by Mr. Stoddard, "[b]etween the modest RGGI price and a dynamic clean energy market, New York's power sector would have clear, economic signals to decarbonize. Without a carbon price in other sectors, however, inter-sector leakages will occur."[18] Although the arguably optimal solution, the Commission no doubt recognizes that this would require action of the legislature.

B. Forward Clean Energy Market

In lieu of legislative action on economy wide carbon pricing, to reflect the cost of carbon in the markets, there should be an explicit mechanism in the market to value the actions taken to provide New Yorkers with carbon free electricity. Capacity markets themselves do not create carbon emissions and the desire for reduced carbon or carbon-free electricity should be accounted for where it exists, either in the energy market or through the implementation of a new market such as the FCEM.

Clean energy resources can be procured faster and cheaper through market mechanisms than through out-of-market approaches. Contracts awarded in state-led procurements substantially increase the costs to consumers, shift the risks to consumers, and limit or slow innovation. Through a concept like the FCEM, New York could procure clean resources at the lowest possible cost and

[17] Stoddard Affidavit at 6.
[18] Stoddard Affidavit at 54.

encourage the innovation and development of new technology.

The FCEM is further detailed in the attached white paper prepared by The Brattle Group.[19] The concept would be tailored to New York, but generally, it is a market-based solution that can value carbon-free resources in a resource neutral way through reliance on a competitive market to ultimately decrease greenhouse gas emissions. In addition to the capacity, energy and ancillary service markets that already exist in the NYISO, an additional market would be created for "clean energy attribute credits." These credits would be procured in an annual auction held three years in advance of when the energy is needed. The FCEM would foster actual competition among existing carbon free resources and new entrants. Winning bidders would receive a single clearing price for credits, and, if desired, contracts for *new* resources could be extended for seven years to provide long-term price certainty to support financing. The goal of the auction would be to procure credits equal to a certain percentage of the state's electricity demand in the year implemented and the percentage would increase annually through 2040 when the credits purchased on behalf of New York utilities would equal 100% of electricity use. Renewable Energy Standards would evolve to Clean Energy Standards and RECs would evolve to Clean Energy Attribute Credits and the REC market would become a FCEM. Such an approach represents the lowest cost path to decarbonization through reliance on innovation and broad competition among all types of resources and industry players and across locations with different solar and wind patterns. The use of a smooth downward-sloping demand curve to express a State's willingness to pay for clean energy attributes has a number of benefits, including creating stable pricing and achieving faster carbon

[19] "How States, Cities and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals Through a Forward Market for Clean Energy Attributes," prepared by The Brattle Group (Sept. 2019). *available at*: https://brattlefiles.blob.core.windows.net/files/17063_how_states_cities_and_customers_can_harness_competitive_markets_to_meet_ambitious_carbon_goals_-_through_a_forward_market_for_clean_energy_attributes.pdf.

abatement than other non-market mechanisms. Specifically, with the sloping demand curve if larger amount of clean energy attributes are available at lower than expected costs, the auction would automatically clear more supply at a lower price to allow an accelerated decarbonization trajectory.

As Mr. Stoddard explains, FCEM is "more efficient and effective at reducing carbon emissions than existing programs because it harnesses market forces more effectively."[20] In short, clean energy resources could be procured faster and cheaper through market mechanisms than through out-of-market alternatives. Through the FCEM, New York could procure clean resources at the lowest possible cost and encourage innovation and the development of new technology. While the FCEM would help attract new resources, the capacity market would work has it has for 20 years to assure reliability in New York.

C. Other Alternatives

If the State is not inclined to pursue a concept akin to the FCEM, there is a suite of other approaches the State could take to better reflect environmental attributes in the market, as discussed in the Affidavit of Robert Stoddard attached hereto. Such as changes to the existing market structure could include:

- developing a program akin to ISO-NE's Competitive Auctions with Sponsored Policy Resources ("CASPR") program for New York, under which the entry of new publicly-sponsored resources in the capacity market is coordinated with the exit of older existing capacity resources willing to permanently leave the market;
- improving scarcity pricing through an operating reserve demand curve;
- expanding the range of ancillary services to include such products as regulation up and regulations down and a ramping product to better reflect the pricing of services needed to support the grid; and
- increasing the penetration of smart meters and smart tariffs to match will be important to provide customers and their load-serving entities the opportunity to plan power use more wisely and to support investments in energy efficiency and energy controls.

[20] Stoddard Affidavit at 39.

In short, there are a variety of productive steps the State could take to foster its environmental goals while ensuring the reliability of the power system.

V. **Responses to Questions**

Below are responses to questions posed in the Notice.

1) Are the State's energy policies and mandates, such as those related to Offshore Wind, photovoltaics, other renewables, and energy storage compatible with the NYISO's resource adequacy mechanisms? If not, what issues are manifested? Also, if not, how could they be aligned?

- When the State's energy policies provide subsidies for favored resources that participate in the capacity market, and the capacity market does not have a specific way to price those resources, those resources will suppress capacity prices and harm economic generation that the state has traditionally relied upon to maintain resource adequacy. As discussed in Section IV above, this issue is pending before FERC in the PJM capacity docket. There are two avenues available to address the issue: (i) to revise the capacity market to remedy the impact of the subsidized resources, or (ii) refrain from subsidizing resources to advance environmental goals and establish a competitive market structure, like the FCEM to compensate and incent the development of such resources.

2) Does the interaction of policies and market structure mechanisms result in safe and adequate service at just and reasonable rates for customers?

- No. When competitive market mechanisms are side stepped to advance the State's environmental policies, consumers pay substantially more than if those resources or their attributes were acquired through a competitive market. See Section IV above.

3) Is an ICAP product an effective long-term solution for resource adequacy given the required future generating resource mix, which may have lower marginal costs or different availability profiles than many current generation resources in operation? What are the salient attributes of such long-term solutions?

- Yes. An ICAP product is a necessary long-term solution to maintain the reliability that New York has experienced for the last 20 years. Other regions have experienced similar results. See Section III above. To achieve the necessary resource mix to achieve New York's environmental goals there are other mechanisms the State can adapt like the FCEM and the approaches discussed in Section IV.

4) Is there a preferred mechanism(s) for ensuring resource adequacy? What are the cost impacts and benefits to consumers under the various potential resource adequacy mechanisms?

- As discussed herein, ICAP is the preferred mechanism for ensuring resource adequacy.

5) Should alternative approaches be considered to ensure the procurement of generation resources is aligned with State policy goals. If so, which ones? Are there existing or proposed models

which might be instructive, such as the State overseeing LSEs' resource adequacy portfolios (e.g., an approach similar to the one used by California) or restructuring NYISO rules to accommodate State public policies (e.g., a Fixed Resource Requirement Alternative, as proposed by FERC Order issued on June 29, 2018 in Docket No. EL16-49, ¶160 et seq.)?

- Alternative approaches should be considered, but not a California like approach. See Sections III and IV.

6) What is the State role with respect to resource adequacy matters that best serves New York's electricity customers with safe, adequate, and reliable service at just and reasonable rates in the context of state policies?

- NYISO should maintain responsibility for the capacity construct.

7) What, if any, next steps should the Commission take with respect to resource adequacy matters?

- See Section IV.

VI. Conclusion

Thank you for considering these comments in formulating a path forward that would allow the State to maintain a reliable electric system while advancing its environmental goals.

Respectfully submitted,

/s/ Cortney Slager
Cortney Slager
Assistant General Counsel, Regulatory
NRG Energy, Inc.

Attachment A

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission to Consider Resource Adequacy Matters	Case 19-E-0530

STATEMENT OF ROBERT B. STODDARD
ON BEHALF OF NRG ENERGY, INC.

I. QUALIFICATIONS

1. My name is Robert B. Stoddard. I am an economist and principal of Power Market Economics LLC at 28 Monument Square, Portland, Maine 04101. I am also the president and chief executive of GWave LLC, an ocean wave energy technology firm. As CEO of GWave, I provide executive leadership for a technology startup developing a new generation of ocean wave energy converters. Prior to joining GWave, I led the energy practice at Charles River Associates, a global consultancy, where I remain a senior consultant. Maine Governor Mills appointed me to a three-year term to the Energy Working Group of the Maine Climate Council, which is charged with establishing strategies and initiatives to help the state meet its greenhouse gas reductions and renewable energy generation targets as it works to combat climate change, and to make sure Maine communities, industries and people are resilient to the changes the region is facing.

2. My consulting work focuses on electricity industry restructuring, capital investment in power markets, and providing both strategic analyses and testimony for utilities, generation owners, and governments regarding the practical implications of market design. I have frequently testified to the Federal Energy Regulatory Commission (FERC) as well as to state utility commissions and legislatures on competitive market design, rates, and market power issues, particularly in the regions managed by the northeastern Regional Transmission Organizations. Related to this docket, I was closely involved in the original proceedings to implement modern capacity market designs in both the PJM Interconnection, L.L.C. (PJM) and ISO New England, Inc. (ISO-NE) markets, and I have worked on capacity and other issues in New York for Con Edison, several generation owners, and the New York City Economic Development Corporation, among others. I was an invited speaker at the 2017 FERC technical conference on state policies and wholesale

markets, presenting a paper "RTO Markets Must Change to Accommodate State Policies,"[1] and the at the recent Massachusetts Office of the Attorney General Symposium "Wholesale Market Design in a Low/No-Carbon Electricity System."[2] I hold degrees in economics from Amherst College and Yale University. My complete *curriculum vita* is attached as Exhibit RBS-1.

II. PURPOSE AND SUMMARY

3. I have been asked by NRG Energy, Inc. to provide my perspectives on the questions raised by the Commission in this case, with particular focus on the role of a capacity market as a component in the overall New York power market structure. I begin by reviewing the historical role of the capacity market and the relationship between capacity markets, the primary product markets—energy and reserves—and the markets for environmental attributes. Section IV then provides a survey of the design of resource adequacy markets in other jurisdictions. I conclude in Section V with five recommendations for how to evolve New York's markets to better accommodate state policy resources and to achieve state environmental policies while assuring reliable electric service at reasonable cost:

    a. Provide transparent market prices for all clean energy through a Forward Clean Energy Market;

    b. Implement an all-sector carbon price;

    c. Reform scarcity pricing of energy and reserves;

    d. Expand the range of locational ancillary services; and

    e. Better engage demand-side participation.

4. Capacity markets serve a central role in New York's electricity market. A reliable, resilient bulk power system is a core state policy. The capacity market is the primary means to ensure that the system operator, the New York Independent System Operator (NYISO), will have enough resources, located strategically on the grid, to meet expected peak loads with a sufficient reserve margin. The market provides a revenue stream, supplemental to

[1] *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., And PJM Interconnection, L.L.C.,* FERC Docket No. AD17-11-000. Prefiled comments "RTO Markets Must Change to Accommodate State Policies", April 2017, and invited remarks at FERC Technical Conference, May 2017.

[2] Office of Attorney General Maura Healey (https://www.mass.gov/lists/energy-market-symposium-2019-wholesale-market-design-in-a-lowno-carbon-electricity-system. My paper is available at https://www.mass.gov/doc/stoddard-paper-panel-2/download.

expected earnings from the sale of energy and other products, that is competitively determined, location specific, and just sufficient to secure capacity commitments from enough suppliers to support reliable grid operations. Payments are subject to performance requirements, better to ensure that resources being paid to be available are in fact operating when needed.

5. The capacity market has performed this core role admirably over its twenty years of operation. New York has maintained adequate planning reserves throughout, both statewide and in constrained zones, as was the goal of the capacity market design. State policies have moved beyond just providing reliable power at least cost, though; New York has adopted the Climate Leadership and Community Protection Act ("CLCPA"), the most comprehensive and ambitious clean energy goal in the State's history. One element of the CLCPA is a transition of the grid so that 70 percent of New York's electricity comes from renewable energy sources by 2030 and 100 percent by 2040. The concern is whether the capacity market is systematically and irretrievably biased towards low-capital resources, such as gas-fired combustion turbines and combined cycle plants, and consequently pushes against the CLCPA targets. This same question is being faced throughout the northeast.

6. As New York transitions to a low-carbon economy, capacity markets will continue to serve a vital role of ensuring grid reliability. I agree though, that the full suite of New York's energy markets, including energy, reserves, and capacity, requires thoughtful review and potential reformations. Capacity markets hold a mirror to those primary markets: robust earnings in the primary markets gives a resource a competitive advantage in clearing the capacity market. Conversely, if primary market earnings look weak going forward for a particular resource class, those resources won't be picked up in capacity auctions and will likely retire. I would suggest, therefore, that if the Commission is dissatisfied with the results of the New York capacity markets, then the focus should be on improving the primary markets. Improve those markets to enhance earnings potentials for clean energy sources and the resources needed to integrate those reliably, and the capacity market outcomes will follow suit.

7. Many economists, including me, have spent much of the past 20 years working to refine and improve capacity markets with the goal of ensuring that they meet the grid's reliability needs as cost-effectively and efficiently as possible. Likewise, the energy markets are also designed to minimize costs of delivering electricity reliably. To achieve the CLCPA goals, the markets need to evolve to reflect the *societal* costs of the energy sector, not just private costs. Moreover, the reliability needs of a grid composed principally of conventional

generators, able to start and operate on controllable schedules, are very different than reliability needs when intermittent resources like wind turbines and solar arrays account for a large portion of energy generation. Once we transparently align product definitions and payment streams with state policies, capacity and energy markets will continue to serve in their core function of facilitating efficient investment in a reliable power grid that simultaneously meet the state's energy policies.

III. THE EVOLUTION OF CAPACITY RESOURCES IS DRIVEN BY PRIMARY MARKETS

8. Capacity markets are, as Professor Bill Hogan quipped, the suspenders of a belt-and-suspenders approach to power market design. In theory, expected revenue from sales of energy, ancillary services and (when applicable) environmental attributes should ensure sufficient investment in generation to meet grid needs. Why? Because energy and reserves prices run very high when supplies are scarce, ranging above $1,000/MWh to as high as $9,000/MWh in some markets. If investors see the potential for frequent shortfalls, they should build new resources to capture that scarcity premium. Conversely, in a market with oversupply, generation owners will retire unprofitable resources. This ebb and flow of investment based on market expectations of future scarcity premiums should lead the market to a natural equilibrium of supply and demand—the "belt" of the belt-and-suspenders.

9. While it is certainly possible to rely solely on the primary markets to provide the market signals for investment, it requires exceptional political and regulatory will to let these markets work—including tolerating very high prices and capacity shortfalls, particularly in the context of the highly interconnected grids of the northeast, where reliability issues in one RTO can easily spill over into another. From an economics point of view, three factors support including the "suspenders" of a capacity market in addition to robust price formation in the primary markets:

    a. First, various factors may artificially suppress the frequency of realized high prices, such as bid mitigation by market monitors, units dispatched for reliability that are disallowed from setting the clearing price, and *ex post* litigation clawing back supposedly excess earnings.

    b. Second, this "natural equilibrium" level of capacity reserves may be lower than the installed capacity reserve level that is judged prudent by market operators and regulators. While purely market-driven allocation of investment in other sectors-say, strawberries or hotel rooms-works well, a shortfall of strawberries or hotel rooms has limited impacts on the rest of economy. By contrast, major shortages on the power grid can be highly disruptive and costly.

c. Third, investing large sums in a generation facility to chase uncertain scarcity pricing is risky business, and high risk increases the cost of money. One could imagine, in response to the second problem, shifting the "natural equilibrium" reserve margin up by raising the price cap in a market. While this would raise the expected earnings (assuming the first issue above is addressed), the economic returns are still concentrated in a just a few hours per year. Spreading payments into more hours reduce generators' risk and, therefore, the required rate of return on investment. This reduction, in turn, lowers consumer costs.[3]

10. Capacity markets were created to address these three problems while (largely) preserving the incentive effects created by locational marginal prices for energy and reserves. From the 30,000-foot level, capacity markets are fairly straightforward. The market operator determines a target for the quantity of capacity resources for an upcoming year, based on expected peak loads and detailed engineering studies. When there are major transmission constraints in the region, the operator may also specify targets for locational reserve margins. For example, the NYISO targets having enough resources within New York City's peak load to meet 82.8% of the city's expected peak usage. The market operator then conducts an auction to procure capacity commitments from qualified resources to meet these overall and local requirements.[4] The auction clears at a capacity price (or prices, if locational constraints bind) set by the bid of the marginal supplier(s), which in turn should equal that supplier's expected shortfall between the resource's avoidable costs and expected revenues earned in the primary markets (energy, ancillary services, and environmental attributes). Capacity resources have certain obligations, including bidding energy into the market and delivering that energy when called on by the system operator. Failure to perform incurs financial penalties, helping to ensure that, by design and

[3] A counter-argument is that consumers can contract with suppliers to reduce the risk that they each face in a volatile energy market. In New York, as in most retail-choice states, however, consumers have the right to change suppliers at least annually and few have the interest or incentive to shop for electricity suppliers, leaving a substantial fraction of customers on default service. Moreover, there is no obligation for competitive retail suppliers to contract forward, and indeed many of these companies do not have the credit capacity to do so. These factors lead to incomplete contracting between load and resources.

[4] The NYISO, like its neighbors PJM and ISO-NE, procures capacity with a downward-sloping demand curve, so they may under-procure resources if price is high or over-procure if price is low. This mechanism reduces the temporal volatility of capacity prices, which both reduces risk (and therefore costs) to suppliers and rate volatility for consumers.

maintenance, capacity resources will have high availability when needed most to serve peak demand.

11. Without a capacity market or some other resource adequacy (RA) mechanism, the primary markets would result in *some* level of installed resources, but there is no reason to believe that the resulting IRM would achieve the reliability standards set by the New York State Reliability Council (NYSRC). Adding a capacity market or other RA mechanism provides extra revenue, if needed, to top up the available resources to comply with those reliability standards. The capacity market transforms the IRM from an *output* to an *input* linked directly to the NYSRC's standards.

12. Although the capacity market secures resources in the market, which resources *clear* in the capacity market is driven by demand for the ability of those resources to earn revenues in the other NYISO markets (energy and ancillary services) or from their environmental attributes (RECs and ZECs). As noted above, resources that have high expected earnings from these products will deduct those earnings from their capacity market bids. The capacity market, therefore, is a mirror of the condition in those other markets: if the mix of resources clearing the capacity market does not match the regulators' ideal, the first place to look is at the primary markets. How can these primary markets be improved or augmented so that the resources with the highest value from a *policy* and *operational* perspective also have high enough earnings to have the lowest revenue gap that needs filling in the capacity market?

13. The argument that capacity markets favor conventional generation and, therefore, slow needed transitions is countered by recent experience. Capacity markets in the northeastern RTOs have allowed for a rapid evolution of the power grid. In 2000 coal-fired generation accounted for 11 percent of New York's installed capacity, while today it accounts for 2 percent of installed capacity but only 0.5% of energy.[5] Coal is succumbing to three market forces.

    a. Innovation in unconventional gas crushed natural gas prices and had a profound negative impact on the earnings potential of coal-fired plants in the energy markets.

[5] NYISO, *Power Trends 2019*, Figures 15-16. (available at https://www.nyiso.com/documents/20142/2223020/2019-Power-Trends-Report.pdf/0e8d65ee-820c-a718-452c-6c59b2d4818b?t=1563799464629)

b. The growing penetration of wind and solar generation is reinforcing the downward slide in energy market prices, further squeezing coal margins.

c. Carbon pricing under the Regional Greenhouse Gas Initiative (RGGI) places high-carbon generators like coal at a cost disadvantage in the energy market to cleaner technologies, and this cost is programmed to rise over time.

As rational investors, owners of coal-fired generation look less to prompt pricing and more to future conditions to make investment decisions, it doesn't take a crystal ball to see a lake of red ink for coal units as these twin market forces continue. Consequently, 23.6 GW of coal-fired generation have either retired or been placed in reserve shutdown in the three northeast RTO/ISOs since 2013, and another 5.9 GWs have announced retirements.[6] The point is that this radical reshaping of the capital stock in these three regions has occurred because of changes in the *energy* markets, which in turn caused these coal plants to be uneconomic in the *capacity* market. Capacity prices are driven by the earnings of other resource types—resources that are able to earn more of their revenues in the energy market. Consequently, capacity payments aren't sufficient to keep the uneconomic coal units in the market.[7]

Coal-Fired Generators Retired or Mothballed Since 2013 By RTO[8]

RTO	Retired (GW)	Announced (GW)
PJM	21.2	4.7
NYISO[9]	0.8	0.8
ISO-NE	1.5	0.4

Sources: PJM Generator Deactivation data (https://pjm.com/planning/services-requests/gen-deactivations.aspx); NYISO "NY Power System Information and Outlook" (https://www.nyiso.com/ny-power-system-information-outlook) and "Generator Status Update 10-09-2019" (https://www.nyiso.com/documents/20142/6480500/Generator-Status-Update-10-09-2019.xls/7ac6c46e-2f84-19b9-ccff-40a300e2d239); ISO-NE "Retirement Tracker External" updated 8/27/2019 (https://www.iso-ne.com/static-assets/documents/2016/08/retirement_tracker_external.xlsx). *Hartford Courant* "Connecticut's Last Coal-Fired Power Plant to be Closed" 2/12/16 (https://www.courant.com/community/bridgeport/hc-last-ct-coal-plant-20160211-story.html). NYISO

[6] Of the 23.6 GW, 23.3 GW has retired and an additional 347 MW have been placed in reserve shutdown ("mothballed").

[7] New York's pending NO_x regulations will effect a similarly dramatic change in the composition of the state's generation fleet, forcing out older peaking units by fiat rather than market forces.

[8] Numbers have been rounded.

[9] Data includes units on mothball and ICAP Ineligible Forced Outage status.

future retirements assume that regulatory changes will require the closure of the remaining coal plants in the state.

14. Conversely, entry of new generating resources in New York and New England broadly aligns with state goals of reducing carbon emissions. "Generation additions [in New York] were primarily natural gas-fueled or wind-powered. Since 2000, nearly 3,000 MW of generation fueled by coal have retired or suspended operation."[10] Shifting from coal to natural gas, however, will not achieve the CLCPA goals; renewable resources need to increase their market shares dramatically and swiftly. Driving the expansion of renewable generation in these states are state policy vehicles which, in New York, are principally the REC contracts issued by NYSERDA, which augment expected energy market earnings enough to make these resources cost-competitive in the capacity markets, displacing inefficient or costly fossil-fueled resources. The continued, healthy growth of renewables in response to markets created to support state policy goals shows that markets can and do work.

15. In summary, if the Commission wants the NYISO to continue to achieve these reliability standards with a high level of confidence, then it follows that some RA mechanism remains necessary. That RA mechanism should complement the primary markets, which are the primary source of the market signals that drive generation entry and exit Two questions flow from these conclusions:

    a. Are there improvements to the existing capacity market design to *accommodate* New York State policy more effectively?

    b. Are there improvements to the primary markets that can help to *achieve* policy goals?

    I take up these questions in the remaining sections of this document.

IV. Markets Serve Customers Better than More Proscriptive Approaches

16. For most of the history of New York power markets, the decision of what generation to build, and what to retire, was made from the top down. The straightforward business decisions by Thomas Edison evolved into the detailed integrated resource planning (IRP) process that created the master plans for statewide transmission and generation expansion. While these plans were largely effective at maintaining grid reliability at reasonable cost, this top-down approach had numerous drawbacks.

[10] NYISO, *Power Trends 2019,* p. 18.

a. The rate-regulated utilities had the lead in developing the plans, and utilities profited by deploying capital, leading to concerns that the utilities were over-investing in plant to increase their profits.

b. Those same utilities employed most of the technical experts, and controlled most of the technical data, that would have been needed to assess alternatives that could be brought forward to challenge the utilities' proposed capital spending.

c. Planners had a strongly conservative bias, avoiding risky innovation. For example, although the combined cycle power plant was introduce in the mid-1960s, with improvements to the technology in every decade thereafter,[11] and with the 1987 repeal of sections of the Fuel Use Act that restricted the use of natural gas by electric utilities, widespread adoption of this efficient combined-cycle technology only occurred in New York after the state's electric industry restructuring in 1998.

d. When new technology was deployed, such as nuclear power plants, utility staff had little to no experience with planning, building or operating the technology. It is instructive, by contrast, that most of the U.S. nuclear plants today are operated by one of the small number of companies that specializes in operating and maintaining nuclear stations, suggesting an economy of scope that utilities, managing their own nukes, could not achieve.

e. The cost of sub-optimal decisions was borne by consumers, not those utilities that made the decisions—except in unusual cases, when an investment might be declared imprudent and full rate recover denied on the asset. Even in an extreme case, like the Shoreham Nuclear Power Plant which never actually reached commercial operation, most of the $6 billion cost of this unused plant was passed on to the utility's customers.

17. A fundamental problem with any central planning exercise such as a utility IRP is that the planners have incomplete information. Even if a utility knows every detail of its own physical systems, it cannot know with certainty the future in which it must operate: how will electricity demand, fuel costs, and technology evolve over the planning horizon? Ironically, as the timetable for an IRP expands to give planners more time to gather and evaluate information to inform these risks, and to give the public and regulators time to

[11] The American Society of Mechanical Engineers, "Forty Years of Combined Cycle Power Plants," ASME Power Division Special Section, October 2002, available at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.800.1755&rep=rep1&type=pdf

evaluate the IRP and supporting studies, the more out-of-date the underlying forecasts become.

18. Competitive markets, properly designed, can help address these issues more efficiently. Open markets bring far more information to the table. Each potential investor works to find opportunities to gain a competitive advantage in the market, whether that be through enhanced efficiency, lowered costs, innovative financial structures, or new technologies.

19. In 1996, this Commission issued its landmark *Opinion and Order Regarding Competitive Opportunities for Electric Service* that restructured the state's electric power sector, replacing the traditional integrated resource planning model with an open and market-based design.[12] The order required vertically integrated utilities exit the power generation business entirely, divesting their existing generation assets and leaving future development to independent power producers. With the formation of NYISO in 1998, transmission planning responsibility also moved from the utilities to the NYISO. The NYISO also was given the responsibility for assuring resource adequacy, as determined by the NYSRC and, from day 1 of its markets, used a capacity market to secure and price capacity commitments—the first ISO to do so.

20. This shift to a competitive generation sector has clearly benefited the state. State-of-the-art generation is being built, displacing less efficient, more polluting equipment, resulting in lower energy prices and a cleaner environment. Investment risks are borne by investors. Market participants have deployed cost-reducing, innovative solutions to generation and transmission bottlenecks, such as the Neptune Regional Transmission System. Novel generation, such as thousands of megawatts of off-shore wind proposals, is being designed and planned using private capital. One innovation can spawn new innovations, not imagined by planners. For example, the NYISO estimates that growing adoption of electric vehicles (EVs) will add 410 MW to the 2030 peak summer load.[13] This estimate appears to discount the potential for EVs to *discharge* during peak periods based on market price signals, turning what could be a liability to grid reliability into an asset.

21. As New York drives towards a strongly decarbonized generation sector, it should renew its commitment to relying on markets to achieve these goals. As discussed above, markets have already delivered substantial changes in the mix of resources in New York. These markets are the foundation for further changes and refinements that will better enable a rapid yet cost-effective move towards cleaner resources, consistent with the CLCPA.

[12] Case 94-E-0952 *et al.*, issued and effective May 20, 1996.

[13] NYISO, *Power Trends,* p. 15.

Conversely, the Commission should resist the temptation to adopt proscriptive, command-and-control approaches to meeting these important policy goals. As I noted above, there are significant risks and costs associated with central planning—even in a relatively stable market. The next decade in the power industry, though, needs to be dynamic and innovative. New technologies and new ideas will be essential if we are to achieve the ambitious CLCPA goals quickly and at reasonable cost. Markets can deliver such innovation most effectively.

V. *EXPERIENCE IN OTHER MARKETS SUPPORTS REFINEMENTS OF NYISO CAPACITY MARKETS TO ACHIEVE NY'S POLICY GOALS*

22. While NYISO was the first system operator to implement a capacity market, the design has changed relatively little since inception. Other markets have subsequently developed alternative resource adequacy mechanisms that, I believe, offer some models for evolving the NYISO markets to help achieve state policy goals more effectively. In this section I summarize some potentially relevant aspects of the resource adequacy mechanisms of PJM, ISO New England, the California Independent System Operator (CAISO), and the United Kingdom. The successes in these markets arise from the same source: enhancements to the primary markets drive investment in resources to meet policy goals, with a sound reliability assurance mechanism to meet reliability requirements.

V.1 PJM

23. PJM stakeholders have been working on a number of issues that are relevant to the Commission in this case. As noted earlier, the PJM market has successfully navigated and enabled substantial retirement in its coal-fired generation fleet, with 21.2 GW of coal-fired capacity retiring or slated for retirement since 2013. While these retirements were driven in large part by the sharp decline in natural gas prices, the impact of RGGI and other state policies are shifting the PJM generation mix towards low- or zero-emission resources. Importantly, PJM's energy and capacity markets have enabled, rather than impeded, this transformation. There are two areas of particular interest for the question of how New York might adapt its markets to enable state policy goals: capacity market mitigation and enhanced reserves scarcity pricing.

V.I.a. PJM's Capacity Market and MOPR

24. PJM's capacity market, the Reliability Pricing Model (RPM), has been successful in maintaining resource adequacy to support reliable grid operations across PJM's footprint, spanning all or parts of 13 states and serving over 65 million people. This success came during a period of rapid transition in the PJM generation fleet. "Last year, 5,605 MW of

generation, mostly coal, retired, while 10,847 MW of new generation, mostly natural gas, came on line. In the last three years, [PJM has] seen 8,081 MW of retirements and 22,818 [MW] of new generation."[14] This transition away from coal has resulted in a 30 percent reduction in emissions since 2005 and annual savings of more than $1.4 billion, even as the capacity reserve margins have remained comfortably above minimum requirements in nearly all PJM zones.[15]

25. As more PJM states adopt policies to increase the role of renewable resources, the state support that such resources receive threatens to erode necessary price signals in the RPM. That there should be a tension at all is perhaps surprising at first; after all, most markets clear substantial volumes through bilateral contracts without disrupting the ability of the spot markets from clearing robustly and establishing a market price for the commodity. Indeed, this is the way that the PJM energy markets work, with a large fraction of energy coming from self-scheduled units. Such self-scheduled energy, though, typically has costs *below* the market price and self-schedules to reduce operational and market risks. Their self-schedules, therefore, typically do not impact energy market prices. In capacity markets, however, new renewables typically have a higher cost, net of expected *market* earnings, than much of the competing capacity offers. Taking into account state subsidies such as above-market long-term contracts, these resources are able to offer at a below-market rate into the RPM, thus lowering the clearing price and crowding out economic resources, including nuclear units and older renewables without state subsidies. Moreover, state policies that have the effect of suppressing prices in a federal-jurisdiction market raises issues of market power and the shift of the costs of renewables support from the states to generation owners.

26. Unfortunately, after years of stakeholder discussions and a series of rejected filings, PJM has yet to resolve this tension between state policies and federal markets. In 2018 FERC rejected both market reform proposals that PJM filed under its Section 205 authority. In April 2018, PJM filed two new proposals[16] that attempt to square the circle of maintaining robust markets while accommodating state policy resources. FERC has not yet issued an

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[14] PJM, *2018 PJM Annual Report*, p. 4.

[15] *Ibid.* p. 16.

[16] *PJM Interconnection, L.L.C.,* "Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market," Docket No. ER18-1314 (filed April 9, 2018) ("PJM Filing").

order in this matter. As I testified in that matter, both approaches raise substantive economic issues.[17]

PJM's Energy Market Reforms

27. PJM has filed a sweeping proposal to reform price formation in its reserve markets.[18] Because PJM co-optimizes its reserve and energy markets, the proposal will also have broad-ranging effects on the energy markets. These changes will have clear impacts on a number of issues relevant for state policy resources of the PJM States.

28. To summarize the core of the reform proposal, PJM proposes to replace its Operating Reserve Demand Curve (ORDC). Currently the ORDC is a stepwise function so that, as the available reserves are drawn down below two thresholds, the synchronized reserve (and energy) prices are bumped up, though fairly modestly, by $300 and then an additional $550 per megawatt. Under PJM's proposal, all reserve products, both in day-ahead and real-time, will have a demand curve, and these curves will affect prices in many more hours and have the potential to increase prices to much higher levels.

29. While the details of the PJM filing are important, they are not relevant here. What is relevant is the idea that increasing available payments during times of relative scarcity in the primary markets—energy and reserves—is important for guiding the development of a reliable, cost-effect power system. As I argued in the previous section, centralized planning cannot possibly foresee all the possibilities and contingencies that may arise during the future planning period, but sound markets will give a strong financial incentive for market participants to seek out these possibilities and address contingencies as they arise. Improved reserves pricing is central in creating these incentives.

30. While the design of NYISO's energy markets are not directly under the Commission's jurisdiction, the state has a clear interest in urging the NYISO to develop an advanced reserves scarcity pricing mechanism similar to PJM's proposed design. Such a shift would:

    a. Increase the proportion of revenues earned in the primary markets and decrease the importance of capacity market revenues;

    b. Provide strong financial incentives to develop and site resources that best support grid reliability;

[17] *PJM Interconnection. L.L.C.* Docket No. ER18-1314, Reply Brief of NRG Power Marketing LLC, 11/6/2018.

[18] *PJM Interconnection, L.L.C.*, FERC Docket No. ER19-1486-000, filed March 29, 2019.

c. Create a better price signal for energy storage and transmission investment; and

d. Enhance the value of energy efficiency and demand response.

Each of these benefits directly contributes to achieving New York's transition to a zero-emissions economy.

V.2. New England

31. New England offers some perspectives on two aspects of market design: forward procurement of reliability resources that incorporates an explicit mechanism to match the entry of new state policy resources with the exit of incumbent resources; and extensive stakeholder development of a new regional market to value clean energy in a more sophisticated and market-based framework than existing state support mechanisms.

New England's Solution to the MOPR Issue

32. New England offers a potential solution for how capacity markets can accommodate state policy resources. Beginning in 2016, the New England Power Pool and ISO-NE began a focused stakeholder process, Integrating Markets and Public Policy (IMAPP), to identify and explore potential changes to the wholesale power markets that could be implemented to advance state public policy objectives in New England.[19] The concerns that prompted this process were chiefly around the Forward Capacity Market (FCM) and, in particular, how state policy resources can and should participate in the FCM.

33. The IMAPP participants proposed a wide range of ideas to address the problem. Broadly speaking, these ideas could be sorted into two categories: those that could help *accommodate* state policy resources within competitive markets with minimal disruption to the economic operation of those markets, and those that could help *achieve* the state policies. The latter focused mostly on changes to the underlying energy and reserves markets by creating a Forward (or Dynamic) Clean Energy Market, which I will discuss in Section VI below. Discussions on accommodations eventually focused on the idea that evolved into the Competitive Auction for State Policy Resources (CASPR), which was subsequently filed with and approved by FERC.[20]

34. In a nutshell, CASPR works as follows: The Forward Capacity Auction (FCA) occurs under the current rules, procuring capacity supply obligations from sufficient resources

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[19] I participated in this process, working with the Conservation Law Foundation initially and, later, a larger coalition including NextEra, Brookfield Renewables and National Grid.

[20] *ISO New England Inc.* 162 FERC ¶61,205 (Issued March 9, 2018).

approximately three years forward, with the MOPR enforced. Consequently, as discussed above, new state policy resources may not clear. ISO-NE then immediately runs a second auction, the CASPR. In this auction, state policy resources that did not clear the FCA may seek to buy out the capacity supply obligation from an existing resource that did clear but was seeking to retire. CASPR, therefore, creates a clear mechanism for a one-for-one megawatt replacement of an existing generator by a new state policy resource.

35. While there were several competing proposals along similar lines, CASPR explicit inducement of exit put it ahead of other proposals in the IMAPP process. CASPR is, in effect, a buy-out of some existing resources—a "cash for clunkers" approach. It therefore not only enables the *entry* of state policy resources but also the *exit* of incumbent resources, most likely an older fossil-fueled generator. The exit of high-emitting resources is itself consistent with New England states' policies, so CASPR kills two birds with one proverbial stone. The MOPR is included in the FCM design to guard against capacity buyers exercising market power by inducing surplus entry in the market and crashing the price—a strategy that several states actively discussed. Because CASPR substitutes megawatts on a one-for-one basis, the entry of the state policy resources does not change the supply balance in the market. CASPR also has the distinct advantage of having been approved by FERC, thus eliminating regulatory risk in proposing this as a design feature in New York. As with any "accommodate" mechanism, however, CASPR creates market distortions. It is likely to suppress prices in both the energy and capacity markets going forward, though, because the incoming state policy resources that clear in the substitution auctions typically have lower marginal costs than the outgoing incumbents. Moreover, the true competitive cost of state policy resources is never bid into the market, removing an important cost signal that could inform state policy decisions.

36. I strongly urge the Commission to endorse markets and market structures that will help *achieve* state policy objectives—such as the Forward Clean Energy Market—rather than merely *accommodate* them. Deep changes to market structures will likely take time to develop, though, and in the meantime finding a suitable accommodative approach as a stopgap may be needed. CASPR would require some customization to the New York capacity market, given the difference in market timing—with New England's market clearing three years ahead of the capacity commitment year, while New York's clears much closer to delivery. CASPR relies on explicit retirement bids into the FCA—that is, offers from resources that are willing to serve as capacity for another year but will retire if the capacity market price is not sufficient.[21] New York's capacity market does not have a

[21] Such retirement bids are subject to a laxer bid mitigation standard in the FCA.

parallel bid type, and it may be more challenging to accommodate short-notice retirement of resources. Nonetheless, CASPR is a reasonably balanced approach that uses markets to guide which resources should be displaced to accommodate new policy resources.

The Forward Clean Energy Market

37. The second important idea incubated during the IMAPP process is the concept of a Forward Clean Energy Market (FCEM). Brattle Group economists and I have proposed two similar ideas for a FCEM or its close cousin, the Dynamic Clean Energy Market.[22] FCEM is designed to *achieve* state policy goals, rather than merely accommodate them, by harnessing competition in a multi-year forward market. The FCEM would replace existing RECs and ZECs with a Clean Energy Attribute Credit (CEAC). The FCEM would operate as follows:

    a. First, states would submit offers to buy CEACs (possibly using a price-quantity schedule), and qualified suppliers would submit offers to sell CEACs. Offers and bids are for an annual quantity in the future, e.g. three years forward. Qualified suppliers would be any resource that contributes to the state's CLCPA.

    b. Next, an independent entity (e.g. NYSERDA or NYISO) would conduct an auction to match supply and demand. This auction sets a reference price. New resources could secure a multi-year commitment to help reduce their risk and, therefore, their cost of money.

38. This FCEM has properties similar to a carbon price, but it differs in certain respects. First, the FCEM is built on a *quantity* target; the price is determined competitively. In comparison to a carbon price, therefore, better aligned with state policy goals, which are also based on quantities.[23] Second, payments are focused solely on preferred policy resources, whereas a carbon pricing system will provide financial benefits to all technologies with emissions rates below the marginal resource's emission rate. While it is economically more efficient to support the use of all carbon-reducing technologies, from a policy perspective some prefer not to provide additional payments to fossil-fueled generators, regardless of their relative emissions rate. Third, the multi-year contracts of

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[22] Spees/Chang/Stoddard, "A Dynamic Clean Energy Market" presentation to IMAPP, May 17. 2017 (http://nepool.com/uploads/IMAPP_20170517_LT_Straw_Dynam_Clean_Energy_Market.pdf); Kathleen Spees *et al.* "How States, Cities and Customers Can Harness Markets to Meet Ambitious Carbon Goals" white paper prepared for NRG, September 2091 (https://www.brattle.com/news-and-knowledge/publications/how-states-cities-and-customers-can-harness-competitive-markets-to-meet-ambitious-carbon-goals-through-a-forward-market-for-clean-energy-attributes-expanded-report).

[23] Compared to a carbon cap-and-trade system, the effects are similar.

the FCEM will better enable long-term, low-cost financing, particularly if there is political risk around the future levels—or even existence—of a carbon price.[24]

39. This FCEM approach is more efficient and effective at reducing carbon emissions than existing programs because it harnesses market forces more effectively. All clean-energy resources compete on equal footing, regardless of vintage or technology.[25] This equal footing lets market forces decide, for example, whether refurbishment of an older wind farm is more cost-effective than building new. Because the market is non-discriminatory, expected earnings from the auction can be factored into capacity offer prices without risk of mitigation. By contrast, the contracts most states (including New York) use today are unlikely to pass muster as non-discriminatory because of restrictions on vintage or technology type.

V.3 California

40. CAISO operates markets that differ in some fundamental ways from those of the NYISO that are relevant for the case at hand. First, industry restructuring is much less advanced, with the three investor-owned utilities (IOUs) and several large municipal utilities still acting as the monopoly retail service provider for most customers and, with that, retaining substantial roles in resource planning and scheduling. Second, the state is much further down the path of decarbonization, and the resulting high penetration of intermittent renewables is having more impact on system operations than elsewhere in the country, including New York. There are some lessons to be learned from the experience, which I will summarize.

Resource adequacy in California

41. Resource adequacy in California is an exemplar—of what New York ought *not* do. The California model is severely broken in many regards. It relies on incomplete contracting by the IOUs and other load-serving entities, a market model for locational constraints that does not align with the operational requirements, and undergirds the whole system with emergency short-term procurements of capacity at non-compensatory prices. In short, it's

[24] It would be possible—and in my estimate beneficial—to scale the payments for a CEAC to the marginal carbon emissions at the time and location of the clean energy injection. This concept featured prominently in the Dynamic Clean Energy Market I proposed in the NEPOOL IMAPP process, after ISO-NE determined that it was technically feasible. Just as there are clear benefits from location-based pricing of energy, using LBMPs rather than a poolwide price, locational CEAC payments create appropriate incentives to match location and technologies of clean energy resources to minimize carbon emissions most cost-effectively.

[25] It is possible to introduce tranches to support, for example, an emerging technology that has not yet achieved the economies of scale that well-established renewable technology enjoy. Doing so, however, risks entangling preferred tranches in the MOPR issue.

a mess that provides some instruction on how *not* to overlay clean energy policies onto wholesale markets.

42. California had an abortive run at restructuring in the early 2000s, leaving a hodge-podge of traditional monopoly functions and competition attempting to coexist—not always easily.[26] The three IOUs divested substantially all of their fossil-fired generation plants to independent power producers, while retaining their nuclear and hydroelectric plants. While the power markets are operated by the CAISO, it was originally designed to operate more as an imbalance energy market, with each Scheduling Coordinator (principally the utilities) submitting balanced schedules from which deviations occur.[27] Load-serving entities have to demonstrate sufficient resources, by location, to meet load, but the locational requirements set for resource adequacy evaluation are misaligned with the operational needs of the grid; to offset this and other issues in the resource adequacy approach, CAISO has, and uses, substantial short-term backstop procurement to ensure the availability of resources it deems necessary. Retail tariff design has led to the installation of large quantities of roof-top solar, so much so as to strongly affect wholesale market operations and design. While I certainly would not advocate that any jurisdiction copy this mélange of design elements, there are three points of interest with respect to resource adequacy.

43. First, a positive aspect of the CAISO resource adequacy model is a strong focus on contracting. Bilateral contracts substantially reduce risk and, therefore, the cost of capital for new projects. In order to meet their Renewable Portfolio Standard (RPS) requirements, the three IOUs conduct periodic solicitations for renewables, as do several of the large customers who are not served by their utility. These contracts, as well as the market activity of the large municipal utilities, have served to underpin a large build-out of grid-scale renewables in the state. California's utilities are focused on meeting their RPS requirements, but they do not focus on securing the necessary, complementary capacity resources to integrate those grid-scale renewables (and the extensive behind-the-meter distributed renewables). Moreover, the timing of contracting requirements for California load-serving entities leaves the CAISO in suspense as to whether the resources it needs for operational reliability will be picked up in a load's portfolio. When they do not, the CAISO

[26] See, *e.g.*, *CXA La Paloma, LLC v. California Independent System Operator Corporation*, FERC Docket No. EL18-177-000 (complaint filed June 19, 2018).

[27] In recent years the market has relaxed some requirements on the balanced schedules and allow more bid-based dispatch.

has to pay for that capacity separately, which is both risky and more costly than an orderly market structure could provide.

44. The second point is a weakness of the contracting approach to RPS compliance—credit risk. Following court findings of liability regarding wildfires, in January Pacific Gas & Electric declared bankruptcy—the second time it has done so, with the previous bankruptcy in 2001. The bankruptcy left in question whether and how PG&E, the courts, and regulators would cancel or amend approximately $42 billion in power purchase agreements it has, principally for renewable resources.[28] While no contracting situation is without counterparty risk, this incident does highlight the importance of adequate credit assurance for load-serving entities entering long-term contracts.

45. Third, and most positively, are the market design improvements CAISO has made, and is making, to respond to the large and increasing share of intermittent renewables on the grid. Many of these improvements could serve as a template for the NYISO as the share of renewables in the state—both grid-scale and distributed—increases. CAISO has invested heavily in improved data systems for tracking not only resource output but also weather, to improve near- and mid-term forecasting. CAISO is also innovative in its reserve markets. In NYISO's reserves markets, regulation can only be carried by resources that can generate above or below their generation set point, which effectively excludes wind or solar resources (which can ramp down but not up) and conventional resources operating at their minimum generation (which can ramp up but not down). CAISO separates the product into Regulation Up and Regulation Down, enabling more market participation and eliminating artificial scarcity. CAISO also developed a parallel construct, the Flexible Ramping Reserve (Up and Down) that provides additional upward and downward flexible ramping capability to account for uncertainty due to demand and renewable forecasting errors. This ancillary service creates a transparent price on what had formerly been accomplished through operator actions that perversely lowered market prices when key resource attributes were in short supply.

V.4 United Kingdom

46. Looking overseas, the United Kingdom has tried several different approaches to market design and, in particular, how to structure incentives for renewable energy. The reason for the relative success of the current design, the Electricity Market Reform (EMR), may

[28] "PG&E's Bankruptcy Judge Leaves Door Open to Shedding Renewables Contracts" Greentech Media, June 10, 2019, available at https://www.greentechmedia.com/articles/read/pge-bankruptcy-judge-leaves-door-open-to-severing-renewable-energy-contract.

inform the Commission in two regards. First, market reforms need to look at all elements of the market structure and design. EMR replaced an earlier market structure largely because of dissatisfaction over the earlier support for renewables, Renewable Obligation Credits (ROCs, functionally equivalent to RECs), but led to a complete overhaul of the energy, capacity, and renewables markets. Second, even following a thoughtful restructuring of the market structure and design, a formal capacity market was included. The suite of reforms has functioned well, enabling an extensive shift to renewables, a marked reduction in coal burn, limited entry by new gas-fired generation, and low and stable prices.

47. The EMR has four core market elements:

    a. Contracts for Differences (CfDs) to support renewables. These contracts are banded by technology maturity, thus allowing the government to have differential levels of support for mature technologies (such as on-shore wind and solar), for developing technologies (such as off-shore wind), and for emerging technologies (such as ocean energy systems);

    b. Carbon pricing, using a competitive cap-and-trade system akin to the U.S. SO_2 allowance trading, with a robust and increasing floor price;

    c. Emissions performance standards, that set hard caps on the emissions rate at any individual generator, thereby effectively forcing retirement or major refurbishment of uncontrolled coal-fired generators; and

    d. Forward capacity auctions, securing sufficient resources four years ahead of the delivery year, and offering 15-year contracts for both major refurbishment and new plant. The term of these contracts was hotly debated, recognizing that longer contracts create more certainty (and therefore lower financing costs) for capital investment, while on the other hand that same certainty shifts risk to consumers and may slow the pace of technology displacement.

48. The results to date are broadly positive. Auction prices for CfDs for of every renewable technology class came in at or below the administrative strike price. This savings was due, at least in part, to the substantial risk reduction renewable resources see with an all-in CfD compared to the previous Renewable Obligations Credit (ROC) system, which was directly analogous to New York's REC system. By eliminating the risk of volatile energy clearing prices over the contract duration, the estimated capital cost was reduced by 3 percentage

points.[29] This decrease in capital costs for renewable energy projects is estimated to save UK consumers about £2.25 billion annually. Capacity prices over the first three auctions were low and stable, with relatively little new fossil-fueled generation clearing, principally to replace coal-fired generation that was rapidly exiting the market either with efficient gas-fired combined cycle plants or peakers that provide system security but little energy.

VI. Recommendations for Changes to New York Markets to Advance State Policy Goals

49. Considering the experience in these other markets, I return to two questions:

    a. Are there improvements to the existing capacity market design to *accommodate* New York State policy more effectively?

    b. Are there improvements to the primary markets that can help to *achieve* policy goals?

50. I recommend that the Commission and NYISO pursue several particular areas of market reform to both accommodate and achieve the state's renewable energy goals reliably and at reasonable cost:

    a. Provide transparent market prices for all clean energy;

    b. Implement an all-sector carbon price;

    c. Reform scarcity pricing;

    d. Expand the range of locational ancillary services;

    e. Engage demand;

VI.1 Designing a market for clean energy

51. New York currently relies principally on RECs and ZECs to provide additional funds to state policy resources. These products are very blunt instruments, however, and are already resulting in costly operational issues in New York. Unlike energy, RECs and ZECs are neither locational nor time-specific. Consequently, a solar farm on Long Island and a wind farm in the Adirondacks receive the same REC value, despite clear differences in the impact of the two resources on carbon emissions. Although both are zero-carbon

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[29] Newbery, D.M. "Towards a green energy economy? The EU Energy Union's transition to a low-carbon zero subsidy electricity system—lessons from the UK's Electricity Market Reform," *Applied Energy*, 179, 1321-1330, available at http://dx.doi.org/10.1016/j.apenergy.2016.01.046

generators, the resources they displace have very different carbon intensities. As the NYISO has documented, the New York power grid west of Central East is principally zero-emission sources, while east of Central East is fossil-fuel heavy, especially after Indian Point's retirement.[30] Likewise, the varying time pattern of generation determines what fossil-fueled generators it displaces and, therefore, how much carbon it is reducing. But RECs and ZECs do not capture these important distinctions.

52. The FCEM design, or its close relative, the Dynamic Clean Energy Market, provide a superior alternative to RECs and ZECs. All clean energy markets resources are paid a premium reflecting their value in achieving the state's CLCPA goals. Because these earnings are from a competitive, non-discriminatory market, expected earnings would not be subject to mitigation in any NYISO market, thus eliminating potential conflicts between state and federal regulators.

53. The FCEM framework would create other important benefits, including:

    a. Faster and cheaper decarbonization alternatives by including a sloped demand curve and including a banking provision, both of which create more price stability (which is good for both consumers and suppliers) and allow feedback between technological costs and state policy objectives;

    b. Aggregation of demand and supply, reducing counterparty risk, enabling broader participation by both suppliers and load-serving entities, and reducing lumpiness of supply.

    c. A level playing field between new and existing resources, thereby avoiding unnecessary spending on new renewables to replace older vintages of renewable resources that, with some investment, could continue to provide valuable clean energy.

VI.2 Economy-wide carbon pricing

54. Between the modest RGGI price and a dynamic clean energy market, New York's power sector would have clear, economic signals to decarbonize.[31] Without a carbon price in

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[30] NYISO, "Reliability and a Greener Grid: Power Trends 2019" at p.10 (https://www.nyiso.com/documents/20142/2223020/2019-Power-Trends-Report.pdf/0e8d65ee-820c-a718-452c-6c59b2d4818b?t=1563799464629).

[31] I assume that any New York policy would be an overlay to its existing RGGI participation. Clearing prices for CEACs in the FCEM would be lower because of the carbon charges from RGGI, thus providing a complementary rather than competing set of policies.

other sectors, however, inter-sector leakages will occur. When electricity prices reflect the carbon externality but the prices of, say, home heating oil or gasoline do not, the incentive for homeowners to shift to heat pumps and electric vehicles is blunted or even reversed. The best way to stop these leakages is for carbon pricing to be as pervasive as possible. The most economically efficient carbon tax would be a common global tax on all fossil fuels, imposed at the source. If not global, then national, with import and export adjustments. If not global, then statewide. Although pricing carbon will surely lead to certain dislocations, it also raises funds that can, at least in part, be used to help offset those impacts.

VI.3 Reform scarcity pricing

55. At a recent conference organized by the Massachusetts Office of the Attorney General, the widely respected energy economist and Harvard professor, William Hogan, was emphatic: "whatever else you do, do this," where "this" is to adopt a reserve scarcity pricing model along the lines now used in the Electricity Reliability Council of Texas (ERCOT) and has been proposed by PJM. As I discussed above in Section V.2, improved scarcity pricing through an operating reserve demand curve has many desirable properties that make everything else in the market work better—capacity markets, transmission planning, resource siting, *etc*. A thoughtful implementation requires substantial work by the NYISO and stakeholders, but the intellectual groundwork has been thoroughly laid out in the writings of Dr. Hogan and his colleagues,[32] as well as in the work of ERCOT and PJM.

VI.4 Expand the range of ancillary services

56. In a grid where most resources are dispatchable, operating reserves is a fairly tame subject. Indeed, market designers did not give it much thought initially. But as we move towards a world where intermittent generation is a large and growing part of supply, and behind-the-meter solar is adding to load forecast uncertainty, both the need for and supply of operating reserves is contracting. Furthermore, some essential grid support services, such as inertia, never needed to be priced in a world where nearly all generating resources provided the service by their engineering design.

57. As the world changes, the Commission and the NYISO will need to be thoughtful about how these essential reliability products are defined and obtained. California's fractured approach to resource adequacy fails at many levels and shows the risks and costs of relying

[32] See, *e.g.*, Hogan & Pope, "PJM Reserve Markets: Operating Reserve Demand Curve Enhancements" (March 21, 2019) (https://sites.hks.harvard.edu/fs/whogan/Hogan_Pope_PJM_Report_032119.pdf); Hogan, "Electricity Scarcity Pricing Through Operating Reserves", *Economics of Energy and Environmental Policy*, April 2013 (https://sites.hks.harvard.edu/fs/whogan/Hogan_ORDC_042513.pdf).

on contracting alone to achieve resource adequacy. In its ancillary services markets, however, the CAISO has provided leadership that includes products that may be helpful for NYISO as the share of renewables increases. Specifically, the New York markets would be well served by the introduction of a day-ahead imbalance reserve product and separate regulation-up and regulation-down products. Dividing regulation into distinct regulation up and regulation down markets removes an artificial limit on what resources are able to provide regulation. Adding a ramping product, as California has done, will likely be needed as New York's installed solar based increases to avoid the ramping issues created by high mid-day solar generation (the "duck curve" problem), but at present is not needed.[33] The NYISO is already looking at opportunities for improving its ancillary services markets, and these are areas that should be given attention.

VI.5 Engage demand

58. Managing the power system entirely from the supply side will become increasingly difficult and costly as we decarbonize the generation sector. In the extreme, in a world with only renewables resources and storage, the *only* meaningful energy prices must come from demand, providing the financial incentives to defer or reduce consumption. Increasing the penetration of smart meters and smart tariffs to match will be important to provide customers and their load-serving entities the opportunity to plan power use more wisely and to support investments in energy efficiency and energy controls.

59. Part and parcel with this change needs to be a hard look at competitive retail access in New York. Simply shutting down competitive retail access will also shut down the innovation needed to transform New York's power sector. The state's utilities are good at what they do—manage complex transmission and distribution systems—but no amount of incentive rate-making or administrative prodding will transform them into the creative retailers that a competitive retail sector both needs and will create.

60. The Commission should ask for more—not less—from competitive retailers. The Commission should require robust consumer protections and credit-worthy, well-capitalized retailers, to ensure consumer confidence. Engaging demand will necessarily mean linking wholesale and retail prices more directly, but it will not go well if customers are shifted to a time-of-use or real-time rate without the services of an energy retailer to help manage their cost exposure through a combination of energy management and contracts. A more robust retail supply sector, combined with more and higher scarcity

[33] CAISO, "What the duck curve tells us about managing a green grid" 2016 (https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf).

pricing with reformed reserves pricing, would also increase long-term contracting between retailers and power suppliers, which would reduce the importance of the NYISO administrative capacity markets. With a clear value chain between wholesale markets and customer-focused innovation, a vibrant retail market will create the flexible, clean resources on the demand side that will be essential for New York to achieve its environmental goals.

61. This concludes my comments at this time.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission to Consider Resource Adequacy Matters	Case 19-E-0530

AFFIDAVIT OF ROBERT B. STODDARD
ON BEHALF OF THE NRG ENERGY, INC.

I, Robert B. Stoddard, being duly sworn, depose and state that the contents of the foregoing Affidavit on behalf of NRG Energy, Inc. is true, correct, accurate and complete to the best of my knowledge, information and belief.

____
Robert B. Stoddard

SUBSCRIBED AND SWORN
before me this 8 day of November, 2019

____
Notary Public

My commission expires: 10/13/22 HANNA DANIEL
Notary Public, Maine
My Commission Expires October 13, 2022

Attachment B

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

PREPARED FOR

nrg

PREPARED BY

Kathleen Spees
Samuel A. Newell
Walter Graf
Emily Shorin

September 2019

THE Brattle GROUP

Notice

This market design proposal was prepared by authors from The Brattle Group for NRG. The views presented are those of the authors and do not represent the opinion of The Brattle Group or its clients. Any errors are the sole responsibility of the authors.

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Executive Summary

Across the U.S., over 100 cities and multiple states have already made the commitment to transition to 100% clean or renewable energy in the coming years.[1] In the past year, Xcel Energy became the first large utility to commit to 100% renewable energy, and the University of California system committed to 100% clean energy on a short timeline by 2025.[2] Nearly three-quarters of the Fortune 100 companies have adopted sustainability and renewable energy goals.[3]

Achieving these ambitious public and private goals will eventually require replacing much of the current fleet of generation that relies heavily on carbon-emitting coal and natural gas. But such an ambitious transition to clean energy is unlikely to happen on its own, and it is unlikely to be achieved cost-effectively using traditional policy instruments. What's needed now is to acknowledge that transitioning to 50% or 100% carbon-free energy will require some fundamentally different and better policy tools. In this whitepaper, we propose a new forward clean energy market (FCEM) in order to harness technology-neutral, broad-source competition and innovation. The FCEM would provide a competitive, regional market for clean electricity attributes. It would enable states, cities, and customers to achieve their ambitious carbon targets at lower costs. Furthermore, it would complement existing competitive wholesale electricity markets.

The transition to clean energy is unlikely to happen on its own because, at least in restructured states, investment and operating decisions are driven by competitive market forces that do not adequately account for the cost of carbon emissions. Thus the markets underprovide clean energy relative to states' carbon targets. This shortfall has led many states to intervene in the electricity markets to achieve their policy goals. One approach is to procure and subsidize certain non-emitting resources directly. Such an approach may appear expeditious but does not necessarily identify the lowest-cost solutions among the diverse and evolving set of possibilities. The lowest cost path to decarbonization will be discovered only through innovation and broad competition among all types of resources and industry players, and across locations with different natural solar and wind patterns. Only market-oriented approaches will do that. But how can markets incorporate environmental values and find the least-cost solution?

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1 Sierra Club, "100% Commitments in Cities, Counties, and States," 2019.

2 David Roberts, "For the first time, a major US utility has committed to 100% clean energy," December 14, 2018, published in Vox.

Robyn Schelenz, "UC makes bold commitment to 100 percent clean electricity," October 29, 2018, published by the University of California.

3 Advanced Energy Economy, "2016 Corporate Advance Energy Commitments," December 2016.

The classic economists' approach is to internalize emissions costs into markets by charging for emissions, through either taxes or cap-and-trade. Economy-wide carbon pricing is the most efficient approach because it creates the broadest possible competition for abating carbon across all economic sectors and technologies. In the electricity sector, carbon pricing can achieve carbon abatement by making carbon-free sources more competitive, as well as by incentivizing fuel switching from high-emitting coal generation toward more efficient gas-fired generation. Electric sector carbon pricing has proven challenging to implement effectively, however, if applied to only a subset of states, cities, and customers that wish to decarbonize within a highly interconnected interstate market. The main challenge is that electricity production and associated emissions can shift or "leak" from the areas that price carbon to those that do not, unless complicated border adjustments are applied.

For regions that are not able to implement carbon pricing due to political constraints, our proposed FCEM is an alternative approach that can efficiently guide the transformation to a clean electricity sector. The FCEM differs from carbon cap-and-trade in that it will pay clean energy resources for producing energy and displacing fossil generation (rather than charging carbon emitters for their pollution). We view both approaches as economically efficient, but view the FCEM approach as more feasible to implement in some jurisdictions.

The FCEM proposal is built around three core ideas: the first is *competition*, which is critical for identifying the least-cost solutions to a problem this big and with such varied possible solutions; this proposal ensures broad competition across carbon-free energy sources (although it does not incorporate substitution of relatively low-emitting natural gas generation for higher-emitting coal generation, as a carbon price would). The second is *smart product design*, where the marketable product is a clean energy attribute credit (CEAC), which is a certificate for 1 MWh of *clean energy attributes*, not including the energy itself. A marketable product reflecting just the clean energy attributes perfectly complements existing wholesale electricity markets. This allows the combined markets to find the least cost combination of technologies to meet traditional system needs while decarbonizing the grid. Traditional system needs are already rewarded through existing wholesale markets (for energy, capacity, and ancillary services), while the policy requirement to decarbonize will be rewarded through the new market (for clean energy attributes). Together, the wholesale markets and the FCEM can ensure that both system reliability and decarbonization targets are achieved at the lowest possible cost. The third core idea is *multi-year forward procurement,* using an auction design with a three-year forward period and the opportunity for multi-year price lock-in for new resources. This approach has proven successful in supporting financing for new power sector investments. Moreover, the moderate commitment and forward periods are short enough to respond to changes in market conditions and leave the burden of technology and market fundamental risks with developers and investors, who are best equipped to assess fundamentals and risks and invest accordingly.

The FCEM would be administered by a state agency, a multi-state organization, or even an independent system operator. States and cities could submit demand bids for CEACs, consistent with their clean energy goals. Companies or retail electricity suppliers that wish to procure additional clean energy to meet private customers' sustainability goals could also submit demand bids.

Supply offers could be submitted by any resources that are qualified as contributing to the state's clean energy objectives, which could include nuclear plants, renewable generation, and any other resource that does not directly emit carbon and thus helps displace emissions. The market would clear only the lowest-cost supply offers to meet demand, and establish a competitive clearing price at which all transactions settle.[4] Cleared offers would be paid that price for a delivery term of one year (for most resources) or for a multi-year period of approximately seven years (for new resources, in order to provide developers with sufficient long-term price certainty to support financing new projects).

To pursue a market-oriented, cost-reducing approach, a single state or group of states could collaborate to develop and implement the clean energy market through an appropriate agency, possibly with a governance model similar to that used in the Regional Greenhouse Gas Initiative (RGGI). The proven success and low costs achieved through such a design would likely attract additional future participation from more producers, states, cities, and customers over time.

4 It is also be possible to establish technology-specific "carve outs" to ensure a minimum share of the procurements would achieved from nascent technologies that may be higher cost. For example, see the "targeted resources" provision described in a proposal by The Brattle Group and several coalition partners, "A Dynamic Clean Energy Market for New England," November 2017.

I. Why Use A Competitive Market Approach to Achieve Clean Electricity Goals?

The next years and decades will see massive investment in clean energy. Many states, cities, and corporations have pledged to meet most or all of their energy needs from non-emitting resources. This means not only replacing current emitting generation, but also building enough to electrify transportation, heating, and many industrial applications. Electrification is currently the most promising opportunity to cost-effectively decarbonize much of these sectors. The cost of this ambitious investment program could be very high. To minimize the cost, it will be essential to utilize competitive, market-based approaches.

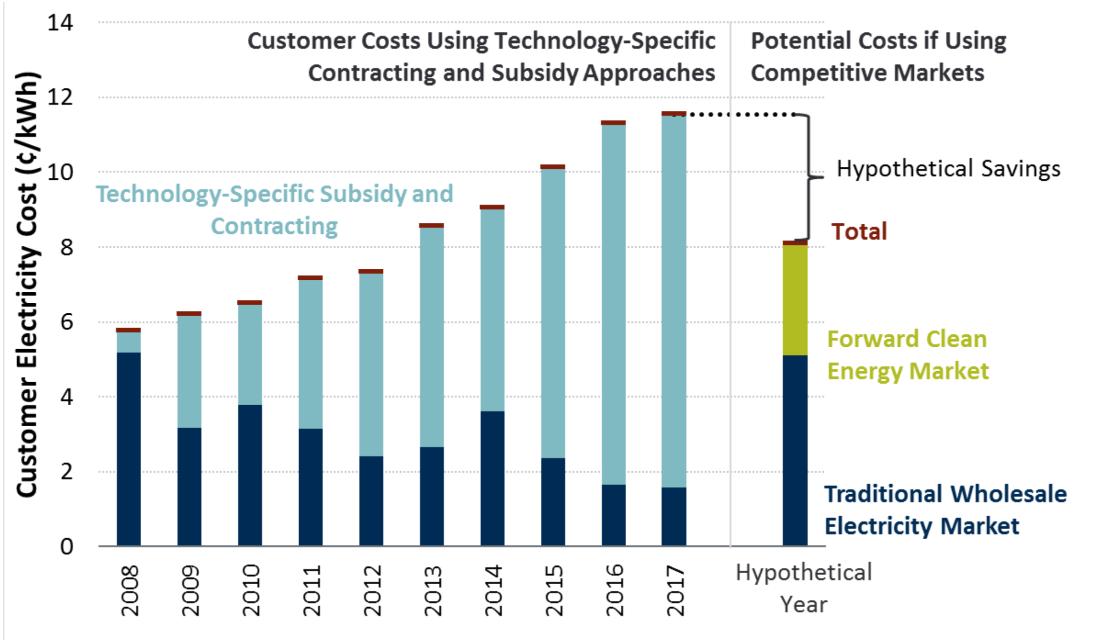
A. Traditional Approaches Will Become Too Costly if Scaled Up to Meet Policy Goals

Although traditional technology-specific subsidies and contracts have succeeded in driving clean energy investment in some jurisdictions, these approaches are expensive, at are odds with existing wholesale electricity markets, and may transfer risks from producers to customers. In many places, total customer bill impacts have been modest so far, but only because the associated goals have been modest as well. The costs of current approaches could rapidly increase as aspirations for a low-carbon electricity system rise.

These concerns have already been borne out in other jurisdictions, where more ambitious objectives met through traditional policy approaches have often led to significant cost problems that have sometimes eventually triggered customer or policy backlash. For instance, over the last decade, the Ontario government signed 20-year contracts with many solar, wind, and other non-emitting resources as part of the overall goal to achieve its current 90 percent clean electricity grid. However, this momentous achievement has come at a high cost: residents there have seen their electric bills nearly double since 2008 even as solar and wind prices have come down every year, as shown in Figure 1. This illustrates the additional costs that can be imposed if policymakers lock in too many inflexible contracts at high prices, even if they are expected to be the lowest-cost alternative at the time those resources are procured.

Looking forward, Ontario is pursuing the opportunity to save customers billions of dollars by transitioning away from their traditional technology-specific contracting approaches and toward a market-oriented, resource neutral market.[5] Figure 1 illustrates the costs reductions that could be achieved if Ontario were to use a set of unbundled, resource-neutral markets for maintaining the 90% clean energy fleet as well as for meeting traditional wholesale electricity market needs.

Figure 1
Ontario Electricity Customer Costs While Achieving a 90% Clean Energy System Compared to Illustrative Costs of Achieving 90% Clean Electricity via a Competitive Market



Sources and Notes:
Values represent wholesale commodity costs, excluding transmission and distribution. Historical traditional electricity market costs represent the weighted-average Ontario Energy price (dark blue), and the Global Adjustment (aqua), which includes resource-specific subsidy and contracting costs. Hypothetical future year costs if using a competitive clean energy market are adapted from a Brattle modeling assessment of the future Ontario market (not intended to reflect a "but-for" estimate of historical costs). Source: "The Future of Ontario's Electricity Markets: Preliminary Study Results," November 30, 2018. The Brattle Group.

B. Broad Competition Will Minimize the Costs of Achieving Carbon Goals

Using a broad market-based approach will focus the industry's incentives toward meeting current and future carbon goals at the lowest possible cost to customers. A truly market-based approach will spur:

- Competition among different developers of the same technology type, who may be able to innovate on more cost-effective ways to design, manufacture, install, or operate assets;

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[5] The Brattle Group, "The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project," April 20, 2017, prepared for Ontario Independent Electricity System Operator.

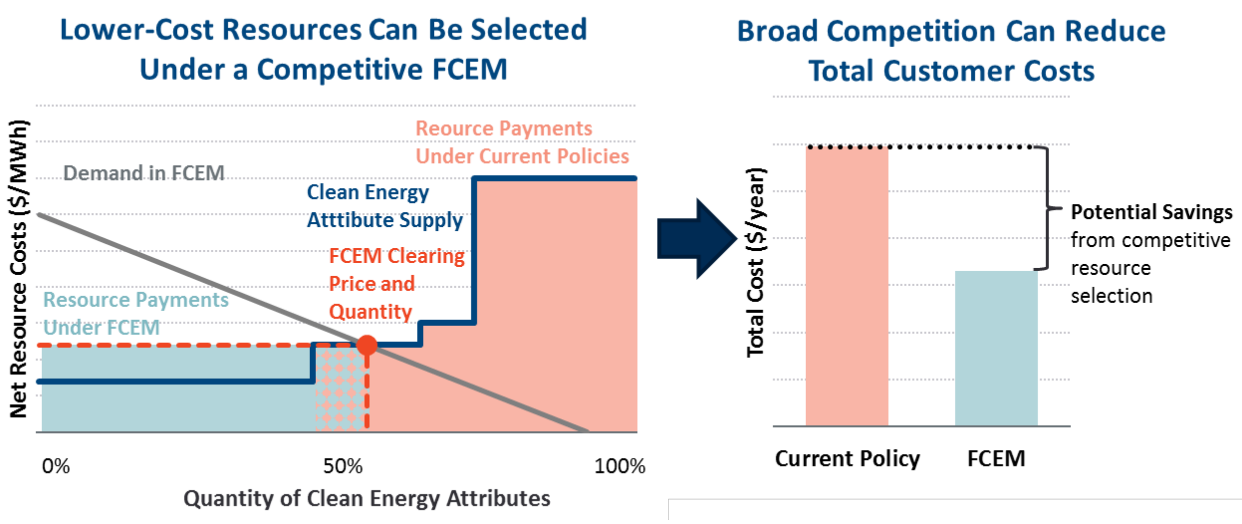
- Competition among different resource types with varying costs and operating characteristics (this is especially valuable as the costs of these technologies are rapidly changing and declining at differing rates);
- Competition among resources across disparate locations (because greenhouse gasses are global pollutants, the specific location of emissions—and the specific location of abatement—does not affect the value of carbon abatement);
- Competition between existing and new resources; and
- Competition among different clean energy resources that provide a variety of grid services, which are compensated via existing wholesale markets for energy, ancillary services, and capacity.

The cost-saving effects of resource-neutral competition are demonstrated in Figure 2, which compares the costs of achieving state clean energy goals if using a system of targeted subsidies (in red) to the costs if using a competitive FCEM (in blue). The left-hand side of Figure 2 shows illustrative costs of a variety of different resources and technologies that could be used to achieve carbon or clean energy goals, with resources sorted in order of increasing costs. The resources highlighted in red would be those selected under traditional policy approaches using technology-specific subsidies and bundled contract procurements. The resources developed under a suite of traditional policy approaches would likely support the development of both high-cost and low-cost clean resources, resulting in relatively high total costs (red bar on the right-hand chart).

The left-hand chart also illustrates the cost-savings that can be achieved with a competitive market. Under a resource-neutral FCEM auction, all sellers will offer in at the minimum price they need in order to develop a clean energy project.[6] The auction can then select only the lowest-cost resources regardless of technology, age, location, or other non-price attributes (resources highlighted in blue). This approach may result in procuring an entirely different mix of resources than would have been supported under traditional policy approaches, including some very low-cost resources that may not have been eligible to participate. As shown on the right-hand chart, the overall costs of such a program can therefore be much lower to achieve the same decarbonization goals (alternatively, the same program budgets can be used to achieve much more ambitious carbon reductions).

[6] This discussion assumes a uniform price auction format; pay-as-bid auction formats incentivize different (strategic) bidding behavior and may result in somewhat less efficient outcomes.

Figure 2
Competitive Markets Drive a Lower Cost Procurement of Clean Resources



This market-based approach can also greatly benefit (primarily corporate) customers wishing to privately exceed state-level targets. These individual customers can benefit from a centralized market platform that would help them purchase their desired clean energy resources at lower costs. This platform would enable private buyers to procure large or small quantities of clean electricity supply at a competitive price with minimal transactions costs, counterparty risks, and or other complexities that arise when contracting individually with developers. Developers, too, will benefit from a platform that offers a predictable opportunity to sell clean energy under standardized terms and under a level playing field. Thus, having a centralized competitive market can improve economic efficiency and lower costs by connecting suppliers with customers who want to set their own targets, goals, and commitments.

C. Technology-Neutral Approaches Maximize Efficiency and Reward Innovation

Another benefit of this proposed market is that it would allow competitive forces to identify the least-cost mix of resource technologies to reach carbon policy goals, and incentivize suppliers to find ways to deliver cleaner energy at lower prices. This market design rewards innovation in carbon abatement technologies and provides revenues for potential developers, new entrants, entrepreneurs, and existing generators alike as they seek to reduce carbon emissions. Competition across technologies avoids relying on policymakers to accurately predict the future of costs and innovation, or to pick “winners” and “losers.” Instead, the market determines how the best mix changes over time to meet increasing decarbonization targets.[7]

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7 As described in our prior work in New England, there are also variations of the FCEM that could introduce technology-specific carve-outs to support a preferred technology. Such a mechanism would

For example, the most cost-effective mix of clean resources could evolve over time. At first, the lowest-cost existing supply might come from older nuclear and hydro resources that need refurbishment to continue operating. Next, high-quality wind resources could provide the lowest-cost clean energy. This may transition to solar resources as the best wind sites become saturated and peaking needs make consistent daytime production most important; this shift to solar would be incentivized based on the combined incentives of the FCEM and the unbundled value for other grid services. Finally, the most valuable technologies may transition to storage and demand response after intermittent supply displaces most fossil generation. Our proposed FCEM will facilitate and encourage this industry evolution. Continuing advances in unbundled energy, ancillary service, and capacity market designs will provide a strong complement to the FCEM to ensure appropriate incentives to avoid curtailments and incentivize flexible resources such as storage.[8]

The central benefit of this markets-based approach is that it incentivizes creative market participants to identify new solutions and technologies that policymakers cannot hope to think of. The ability to attract on that creative potential will be essential to meeting aggressive targets quickly and at the lowest cost.

D. A Market Solution Can Better Align with Wholesale Electricity Markets

A market-based approach such as the FCEM has additional benefits beyond efficiency and cost-effectiveness. One key benefit is improved alignment with existing wholesale capacity, energy, and ancillary service markets. Most importantly, a marketable product reflecting just the non-emitting attributes of qualifying sources perfectly complements existing wholesale electricity markets for energy and reliability attributes. This allows the combined market forces to identify the least cost bundle of multi-attribute resources to meet multi-attribute system needs. This concept is grounded in a mechanism that has been proven to be effective: electricity generators already produce multiple marketable attributes, including energy, capacity, and various ancillary services products. The existing markets incent entities pursuing private profits to make investment and operating decisions that maximize the system value they provide across these multiple products. Adding a non-emitting resource attribute to the bundle of products that can be sold will

increase costs as compared to a fully resource-neutral approach. For more information, see The Brattle Group and several coalition partners, "A Dynamic Clean Energy Market for New England," November 2017.

8 Note that the full carbon abatement value of flexible resources including demand response and storage can also be incentivized under an FCEM on a resource-neutral basis with other clean technologies, but only if there is a mechanism for accurately tracking their carbon value (which traditional renewable energy credit markets have not previously done). For additional discussion of an FCEM approach that fully enables storage and demand response see The Brattle Group, "A Dynamic Clean Energy Market for New England," November 2017.

incentivize all market participants to identify the best resources to jointly supply both traditional grid services and the demand for non-emitting supply.

One important issue in several electricity markets today is the "out-of-market" treatment of resources that receive payments for clean energy attributes. In ISO-NE and PJM, such resources are not allowed to directly participate in capacity markets without being subject to the so called "minimum offer price rules" (MOPR).[9] These rules limit the ability of resources receiving out-of-market clean attribute payments to offer and clear in the capacity market. This can result in two unsustainably detrimental outcomes from a state policy perspective: first, the resource adequacy value of these resources may not be fully reflected, leading to more capacity on the system than needed to meet reliability requirements; second, that customers that are paying for the "out-of-market" resources end up having to pay twice for capacity.

Our proposed approach is that clean resources receiving payments through the clean energy market should be considered "in-market" for purposes of interfacing with the wholesale capacity market, including for purposes of market power mitigation, such as the MOPR. Our design thus bridges the divide between state carbon goals and wholesale market reliability and least-cost planning criteria.[10]

II. What Would a Competitive Clean Attributes Market Look Like?

Our proposal centers on a regional forward auction for the clean attribute of electricity production, known as clean energy attribute credits (CEACs). The FCEM differs from carbon cap-and-trade in that it will pay clean energy resources for producing energy and displacing fossil generation (rather than charging carbon emitters for their pollution). We provide a high-level overview of this FCEM in this section, with substantially more detail included in the Appendix.

In the most basic implementation of this approach as we describe in this paper, the clean attribute product would be similar to unbundled renewable energy credits (RECs) that are used to track renewable energy generation today. A REC represents the clean attribute of energy generation, and unbundled RECs are often sold separately from the original electricity production that generated it. Each REC is tied to a specific delivery year when it is generated. The CEAC product procured in the FCEM would have these same characteristics. Thus, the FCEM can be viewed as a

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9 For a more comprehensive discussion of this issue, see a recent discussion paper by Kathleen Spees, Johannes Pfeifenberger, Samuel Newell, Judy Chang, "Harmonizing Environmental Policies with Competitive Markets," July 2018.

10 The economic rationale for removing the MOPR on such competitively-procured clean energy resources is that a state non-emitting attribute program that is competitively administered and open to all qualifying resources on a non-discriminatory basis that satisfies the principles of competition underpinning the competitive wholesale electricity markets.

natural successor to existing REC markets. However, the proposed market would incorporate several advantages over existing markets.

In the FCEM, state policymakers would mandate a quantity of carbon-free power that they wish to procure for all customers by a given delivery year. The state's mandated Clean Energy Standard becomes the minimum quantity of carbon-free electricity, while allowing for easy and cost-effective over-achievement. At the state level, policymakers can express a desire to accelerate emissions reductions by utilizing this market design that procures more carbon-free power when prices are more attractive (but moderating goals in alignment with budget caps if prices are high).

The FCEM also creates a platform that allows private parties to buy additional carbon-free power. This allows companies, municipalities, public power entities, retail electric providers, and others to exceed the clean energy standard in a cost-effective manner and with minimal overhead costs. Each participant would translate its policy or corporate sustainability goals into a quantity of clean energy, and bid for this quantity in the FCEM. This allows states and customers to control their future and to procure the quantity clean energy resources that matches their policy goals to phase out fossil-fired carbon emitting resources over time.

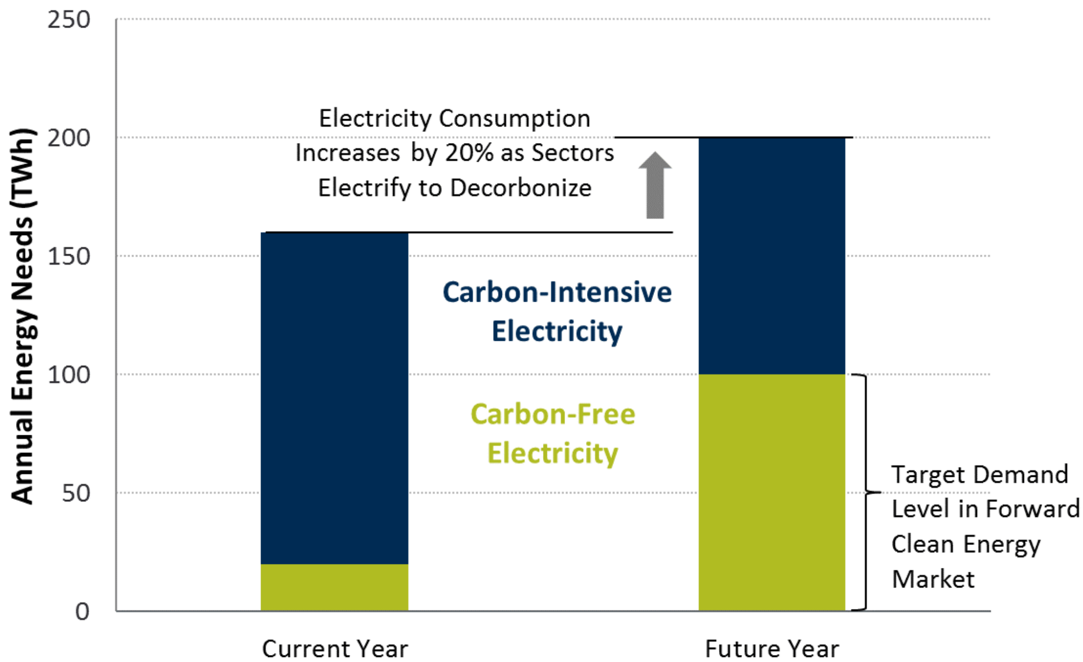
On the supply side, generators who own or are developing resources that produce carbon-free electricity would offer to sell CEACs in the delivery year at a price they choose. The forward auction would set the quantity and price of the CEACs procured for the given delivery year.[11] By procuring carbon-free energy for a future year, the new market would incentivize investment in non-emitting resources. It would provide renewable developers access to a predictable source of revenues, including multi-year commitments for new resources that help to mitigate investor risk and reduce financing costs. Overall, this approach assigns regulatory risk to the states/customers, while leaving technology and cost risk primarily with market participants and investors, who are best able to manage that type of risk.

A. Translating Policy Goals into Market-Based Demand for Clean Electricity

For states that have policy commitments to serve a certain share of demand with clean resources such as through a Clean Energy Standard, these targets would be straightforward to translate into demand in the forward auction, as shown in Figure 3. In this example, the state currently has a small share of clean generation but has a target to meet 50% of demand with non-emitting supply by a certain year. Demand is forecasted to grow to 200 TWh by that future year, so the state target demand level for the clean energy attribute would be 100 TWh. Any willingness to procure more CEACs at low prices, or desire to procure less at high prices, would be represented through the specific shape of each states' demand curve for CEACs.

[11] The delivery year is the period for which resources are committing to produce clean energy in the forward auction.

Figure 3
Example: Translating State Goals into Forward Clean Energy Market Demand



State-offered demand would also be submitted within the context of a commitment to sustained participation over many years in order to mitigate regulatory risks that may be introduced by uncertainties in the total auction demand levels over time. For example, states could be required to commit to a certain minimum demand for a ten-year period, with adjustments allowed as consistent with changes to total load.[12]

Cities, companies, public power, and retail providers might develop their own targets to meet internal sustainability or green energy goals or offer cleaner energy to their customers. These may be in excess of what the state will already procure on their behalf, or instead of it, if located in a state that is not participating in the auction. Thus, each potential market participant has full control of its level of demand for clean energy attributes. Each state or individual buyer would submit its demand for clean energy and the maximum willingness to pay for a specific quantity of CEACs.[13] The demand from each state and individual buyer would be summed into an aggregate market-wide market demand curve, representing to total quantity of CEACs desired by the market at each price, as illustrated in Figure 4.

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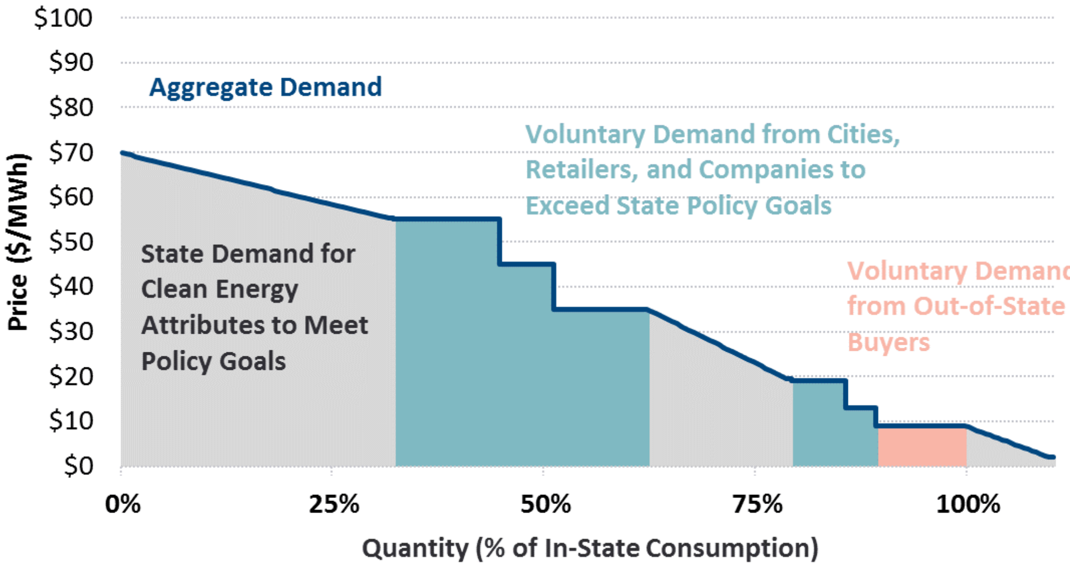
12 Though states could commit to procuring that quantity in repeat auctions over the ten-year period, individual sellers would not be guaranteed ten-year contracts. Instead, sellers would have an opportunity to sell into the auction on a year-by-year basis, but would have to compete each year to sell at the lowest price.

13 Buyers could also use more complex demand curves to represent their willingness to purchase CEACs as a function of price. This would allow them to represent higher willingness to purchase CEACs at low market prices if desired.

Figure 4
Aggregate Demand for Clean Energy Attribute Credits



Notes:
The figure represents the aggregate demand from states (here represented using downward-sloping demand curves) and other independent retailers, companies, and other entities (here represented as discrete price/quantity pairs).

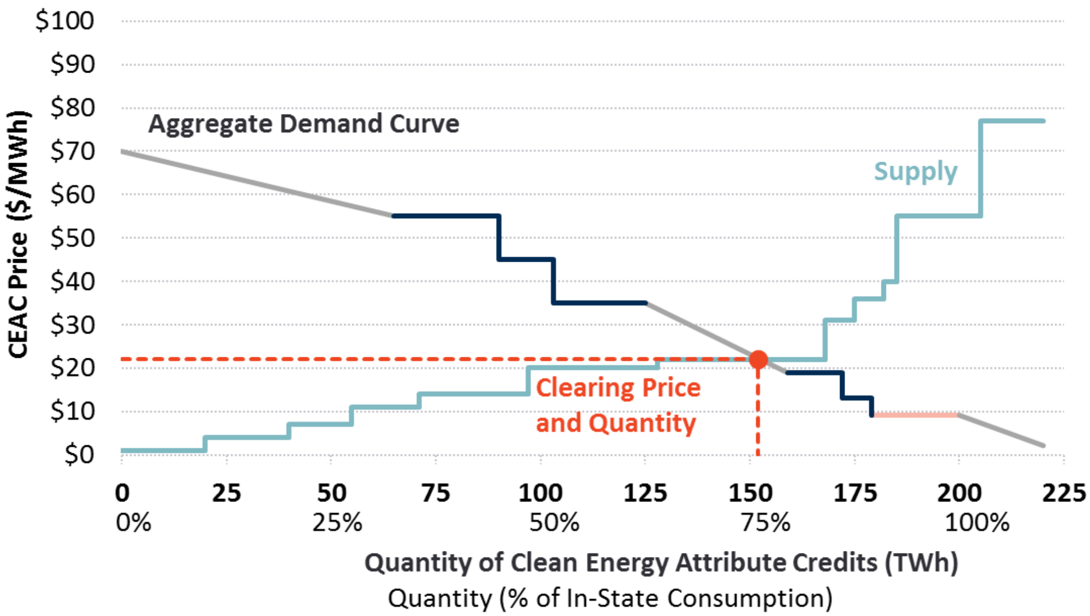
B. Procuring the Most Cost-Effective Clean Electricity in a Competitive Forward Market

A forward auction, which occurs three years in advance of the delivery period, brings together market participants on the supply and demand side of the market. On the supply side, resources would offer in their estimated clean generation capability at a specified price for the delivery period. As the market is designed to be competitive, offer prices should reflect sellers' costs of clean generation, including going-forward costs of being online in the delivery year. Sellers whose resources are also valuable for providing energy, capacity, or ancillary services could offer at low prices into the FCEM because the large majority of the resource's costs will already be paid for by revenues from other wholesale electricity markets. The uniform-price auction would attract and reward the most cost-effective resources. More expensive options would not be selected.

On the demand side, states with mandatory targets for meeting clean electricity goals would make up the majority of bidders. For bids won by state entities, the costs and associated CEACs would be passed through to the retail providers within that state. Other participants including private companies, municipal utilities, electric cooperatives, and retail providers could submit voluntary bids to procure additional clean energy. These participants could use their cleared bids to meet corporate sustainability goals or to offer green energy rates to end use customers.

Aggregate market supply and demand would be cleared in a single-price auction as depicted in Figure 5. The resulting clearing price and quantity would be set at the intersection of these curves, and would determine which resources have an obligation to provide the clean attribute and how much they would be paid for it.

Figure 5
Example: Clearing the Forward Clean Energy Market



C. Features for Advancing Beyond Traditional Clean Attributes Products and Markets

While this proposed FCEM will be similar to existing REC markets as described above, it would also have several important features that will allow it to cost-effectively achieve far more carbon reductions at lower costs than traditional REC markets:

- **Technology-Neutral Participation:** unlike REC markets with tiered participation that segments different types of non-emitting resources and that tend to exclude some clean resource types like nuclear and resources existing prior to established cut-off dates, the FCEM would maximize participation of all non-emitting supply on a uniform basis.
- **Mechanisms to Support Price Stability:** a graduated demand curve for different quantities of CEACs at different prices in the forward market, and a spot auction conducted right before the compliance deadline would mitigate the boom or bust pricing tendencies of existing REC markets.
- **Capability to Support Financing of New Clean Energy Resources:** several design elements would support financing for new resources better than existing RECs, including a multi-year commitment for new resources and a forward auction to support financing of resources with longer development timeframes.

In addition, the proposed market would be flexible and easily tailored to integrate with other enhancements to advance beyond traditional clean energy products and markets. One potential drawback of the market as presented here is its focus on incentivizing non-emitting resources while admittedly not providing incentives for lowering the emissions through fuel switching from coal to gas generation as carbon pricing could.

In an even more efficient but somewhat more complex version of this market, the clean attribute product could be more directly tied to the marginal carbon abatement value of the resources in each year. Thus, resources that are expected to displace more carbon, due to the alignment of their generation profile with carbon emissions on the system, would create more CEACs. In the most advanced version of this approach, the quantity of CEACs created by a non-emitting resource could be dynamically related to the marginal rate of emissions in the market at every location in every real-time market interval. This would incentivize producers to identify opportunities to cost-effectively displace more carbon faster.[14]

III. A Potential Roadmap for Implementation

With sufficient political will, the proposal outlined in this paper could be implemented relatively quickly as a much-needed complement to the existing electricity markets (energy, ancillary services, and capacity). The initiative to create this market could be taken by a single state, a group of states, a group of clean energy buyers, or an RTO.

The market would work best if a state agency such as the Illinois Power Authority (IPA) or an independent organization with a structure such as RGGI or an RTO were to conduct the auction and manage the updating of market rules. If an independent group is chosen to administer the market, a new organization could be created or an existing company specialized in supporting the trade of commodity products could be contracted. If an RTO operates the market, the states could ask the RTO to create the auction and recover any administrative costs from market participants. The responsibilities of this organization would be to administer and update rules, register buyers and sellers, qualify supply, support measurement and tracking, maintain credit requirements, and implement settlements. A state regulatory body would likely maintain regulatory approvals and authority to change market rules, or as in the context of RGGI, the independent entity could develop model rules in collaboration with participants. These rules would then need to be separately ratified by each participating state authority.

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14 The "standardized clean energy attribute credit" would represent 1 MWh of clean energy that displaces a certain quantity of carbon, for example 1,100 lbs of carbon per MWh. Resources would be credited with creating more CEACs if they inject clean energy into the grid at times and places that displace more carbon (and would produce fewer or no CEACs if injecting at times and places that do not displace fossil generation). For more discussion of this idea, see a proposal by The Brattle Group and several coalition partners, "A Dynamic Clean Energy Market for New England," November 2017.

Finally, state utility commissions or environmental agencies would develop state demand bids, in alignment with the commitments to achieve carbon abatement and maintain market sustainability. Large companies, cities, public power, retail providers, and other interested parties could also develop and submit voluntary demand bids.

The competitive marketplace is fit-for-purpose to identify and reward faster, cheaper, and better ways to decarbonize the electricity grid. When developed, the FCEM would allow states, retail providers, end customers, and clean energy suppliers to work in harmony to accomplish the ambitious goals before us.

Appendix: Detailed FCEM Design Proposal

This Appendix lays out a detailed market design that states, cities, regional transmission organizations (RTOs), or others could use for achieving ambitious clean energy goals. This proposal incorporates the demonstrated best practices in competitive market design and offers solutions for the common pitfalls and implementation challenges that many states may face in the transition to a cleaner energy future. This document is intended as a starting point from which additional design refinements could be made; we anticipate that many details will need to be adjusted to match the relevant policy goals and regulatory context in each region.

The FCEM can be administered by a state agency, a multi-state organization, or an RTO. States will submit demand bids for CEACs, consistent with their clean energy goals. The FCEM also allows customers, cities, companies, or retail electricity suppliers to submit voluntary demand bids, if they wish to procure additional clean energy to meet private customers' sustainability goals. FCEM will also accommodate retailers who contract directly with renewable resources and use CEACs from those resources to satisfy their obligation for CEACs for their own customers. Supply offers could be submitted by any resources that are qualified as contributing to the state's clean energy objectives, which could include nuclear plants, renewable generation, and other resources that displace carbon emissions. The FCEM will clear only the lowest-cost supply offers to meet demand and establish a competitive clearing price for CEACs.

The FCEM incorporates a number of design elements that will ensure financeability when new clean energy resources are needed to meet a state's goals. The first is a forward market period as illustrated in Figure 6 below; the auctions and associated financial commitments will occur on a three-year forward basis with payment upon delivery enabling new resources to compete with existing resources. New resources can earn a price lock-in for clean energy payments for a multi-year period of up to seven years, supporting financing arrangements. A spot auction after the end of the delivery period allows for CEAC supply and demand to trade efficiently ahead of deadlines to demonstrate compliance with CEAC procurement targets, for example, if a retail supplier served more load than expected and is thus responsible for procuring more CEACs. Other design elements including a sloping demand curve, CEAC banking, and transparency provisions will further support the stability and price formation features that have proven successful in attracting investments in other competitive markets.

Figure 6
FCEM Auction and Delivery Period Timeline

Table 1 provides a summary of the primary design elements and features of the FCEM, which are described in more detail in the body of this design proposal. Each of these design elements is crafted in a way that draws on the best practices in competitive market design and applies economic first principles. Taken as a whole, this design package can help states, cities, and customers achieve their ambitious decarbonization goals. It will attract innovative players to bring new technologies to the market, drive down costs, and deliver results faster.

Table 1
Overview of the Clean Energy Attributes Market

Design Element	Approach
Product Definition	• The product is an unbundled Clean Energy Attribute Credit (CEAC), similar to an unbundled Renewable Energy Credit (REC) • Optional Enhancement: a "dynamic" CEAC accounting approach can award more CEACs to resources that displace more carbon emissions. This variation can readily enable batteries and focus incentives toward achieving more carbon abatement faster
Demand Participation in the Forward Auction	• State demand will be expressed as a sloping demand curve that will buy higher quantities if supply is available at lower cost • Additional voluntary demand bids can be submitted by cities, public power entities, customers, companies, retail providers, or others. These bids are expressed as price-quantity pairs, representing the willingness to pay for CEACs • Optional Variation: Buyers will have an option to submit a preference for "targeted" resource types, for example to meet carve-outs for preferred technologies such as storage or offshore wind. The auction may procure these resource types even if they are higher cost than "base" resources, although the buyer can specify a limited willingness to pay such a premium.
Technology-Neutral Supply Participation	• Resources are not restricted by type, location, or generation profile; any new or existing clean resources can participate, including hydro, wind, solar, nuclear, storage, or other • Storage resources can participate if their charging and discharging profiles displace system carbon emissions; they offer the value of carbon abatement when discharging, net of any additional carbon emissions they cause when charging
Forward Auction for CEACs	• Forward auction three years in advance of the relevant one-year delivery period to align with development timeline of new clean resources • Up to seven-year commitment period is available to new resources, over which time the price is locked-in to guarantee revenue stability
Bilateral and Spot Markets for CEACs	• Ongoing trading before and during the delivery year, with a final spot auction after the delivery year allow supply and demand participants to continually adjust their positions until the compliance deadline (at which point all load serving entities must demonstrate compliance with the clean energy standard, and resources must have fulfilled their delivery obligations)
Monitoring and Mitigation	• Targeted mitigation measures to prevent large suppliers from exercising market power through physical or economic withholding
Wholesale Market Alignment	• Operates well with existing wholesale markets and maintains incentives to maximize energy, flexibility, and reliability value to the grid • CEAC-based revenues are counted as "in-market" in the capacity market, i.e. not subject to minimum offer price rule (MOPR) provisions that exist in some regions
Competitive Retail Market Alignment	• In states with retail choice, the CEAC is implemented as an obligation on retail providers to meet a certain fraction of their delivered load through clean energy, e.g. 50% by 2030 • Retailers can comply either by making their own CEAC supply arrangements (with self-supply volumes netted out of auction settlements), or by relying on the centralized auctions (passing the costs on to customers) • Retailers compete to offer innovative retail energy options to customers, including additional (up to 100%) clean energy. Retailers can participate in forward, bilateral, and spot markets and develop hedging strategies to minimize cost and risk

A. Clean Energy Attribute Credit Product Definition

The FCEM is a forward auction designed to procure the clean attributes of electricity production, or clean energy attribute credits (CEACs). One CEAC represents one MWh of delivered clean energy supply. By procuring (and then retiring) a given quantity of CEACs that corresponds to the percentage of load to be supplied by clean resources, the state or customer can ensure that the clean electricity goal is achieved.

1. Technology-Neutral, Unbundled Clean Energy Attribute Credits

CEACs are a natural successor to renewable energy credits (RECs), which have been used for many years to track renewable energy generation and compliance with renewable portfolio standards (RPS). Like RECs, the CEACs will be defined as an unbundled attribute, meaning that they are sold separately from the original electricity that produced them. Thus the “brown power” value of the same asset can be separately sold into the wholesale power markets or to a bilateral counterparty. The CEACs represent only the non-carbon-emitting attribute of the energy generation. They do not include other environmental or non-environmental value attributes, such as NO_x emissions or waste disposal.

There are a few main distinctions between RECs and CEACs:

- CEACs are a resource-neutral, uniform product. A CEAC is awarded whenever a resource generates one MWh of non-carbon-emitting electricity regardless of the resource type, resource location, or resource age. This is different from RECs which often represent multiple tiers or technology-specific carve-outs that segment the REC markets into sub-markets that limit competition among technology types and vintages of resources.
- CEACs will be expanded to include more resource types than have been qualified in the REC markets; CEACs will continue to be awarded to renewables, but will also be awarded to nuclear, storage, and carbon capture and sequestration (CCS), and any other new technology sources that could be demonstrated to provide clean electricity.
- In its simplest form, a single CEAC is created for each MWh of clean energy produced, which is the same definition as a REC. However, we also propose a more advanced option for a “dynamic” CEAC product that would award a varying quantity of CEACs in proportion to the volume of carbon displacement achieved by each clean MWh produced (see Appendix H.1 for details).

The importance and value of the unbundled CEAC product will be amplified by the FCEM design as a major advancement beyond traditional approaches relying on bundled power purchase agreement (“PPA”) solicitations or technology-specific subsidies. The FCEM is designed to procure only the CEACs and not the capacity, energy, or ancillary services that may be produced. The procurement of these unbundled attributes will introduce large societal and customer cost savings as compared to traditional approaches relying on bundled long-term contracts that have historically procured RECs alongside the real energy and capacity value that a clean resource might produce. The unbundling of CEAC procurements from these other value streams will require the clean resource seller to separately market their energy, capacity, and ancillary services into the wholesale market or to other buyers. This "value stacking" of revenue streams can guide private investors to shift their investment decisions toward resources that provide the most overall value toward carbon abatement as well as providing essential grid services, while balancing that value against resource costs.

Customers also gain cost savings by limiting their payments to only the clean attribute values they require and avoiding the need to pay for the full investment costs of a new clean resource. This avoids locking customers into a long-term PPAs with clean resources that offer the clean attribute that the customer wants, but in a bundled contract that also includes energy and capacity that the customer does not want (e.g. because the energy or capacity produced does not match term, quantity, location, or temporal profile that best matches the customer's own consumption. Customers and state solicitation agents further avoid the need to apply deeply uncertain administrative judgments in how to appropriately value resources with different energy profiles or capacity values. Customers and suppliers alike will benefit from a standard product format that avoids the significant transactions costs, counterparty risks, and risk allocation challenges associated with bilateral contracting.

An enhanced CEAC product definition would define each credit in proportion to a standard expected quantity of carbon emissions abatement, thus awarding more CEACs to clean energy resources that displace more carbon. This definition would more flexibly and accurately account for the carbon abatement value of different resources, which varies depending on their location and time profile of generation (both of which affect the carbon emissions they can displace). This alternative product definition, which we call a "Dynamic" CEAC, can also reward and incentivize storage and other resources that have carbon abatement value but would not be compensated under the simpler CEAC definition. We discuss the Dynamic CEAC in detail in Appendix H.1.

2. Clean Energy Attribute Credits Qualification, Tracking, and Accounting

The accounting process for CEACs can rely on the same or similar qualification tracking mechanisms as those used for tracking RECs.[15] To enhance the tracking system to align with the

[15] Existing North American REC tracking systems include: Michigan Renewable Energy Certification System (MIRECS), Midwest Renewable Energy Tracking System (M-RETS), New England Power Pool Generation Information System (NEPOOL GIS), Nevada Tracks Renewable Energy Credits (NVTREC), New York Generation Attribution Tracking System (NYGATS), New American Renewables Registry (NAR), North Carolina Renewable Energy Tracking System (NC-RETS), PJM-Generation Attribute

CEAC product definition, states first need to establish qualification criteria for earning CEACs. As is already the case in REC tracking systems, states will need to establish a methodology for verifying the generation of each credit using on-site meter data. After verification, CEACs will be awarded to the registered asset owner. Once the asset owner receives the CEACs, they can then transfer the credits to other parties. These exchanges might include transfers related to bilateral contracts, transfers for the purpose of fulfilling exchange trades, or submissions to the FCEM market administrator in order to fulfill FCEM sales obligations. Buyers, sellers, and traders can also hold the CEACs on account as needed until they retire or resell the credits.

B. Supply and Demand Participation in the Forward Clean Energy Market

The FCEM will enable supply and demand to transact for clean energy. Demand for CEACs will reflect state, city, company, and customers' clean electricity goals. States' policy goals will be translated into a clean energy standard imposed on load serving entities (LSEs) and represented in the auction as a downward sloping demand curve (see Appendix E for details on the mechanics of interactions between the forward auction and retail markets). The supply side will reflect the cost at which resource owners can deliver clean electricity. The centralized marketplace with a standard product design will offer a number of benefits including enhanced liquidity, enhanced transparency, low transactions costs, and low counterparty risk.

1. Demand Participation

States, cities, companies, and LSEs will comprise the demand in the FCEM; buyers specify their demand bids by providing price and quantity pairs that reflect the maximum quantity of CEACs that they will wish to purchase over a range of prices. These individual demand bids reflect each customer's willingness to pay to meet their own goals, ensuring no customers are forced to subsidize other customers' demand for CEACs.

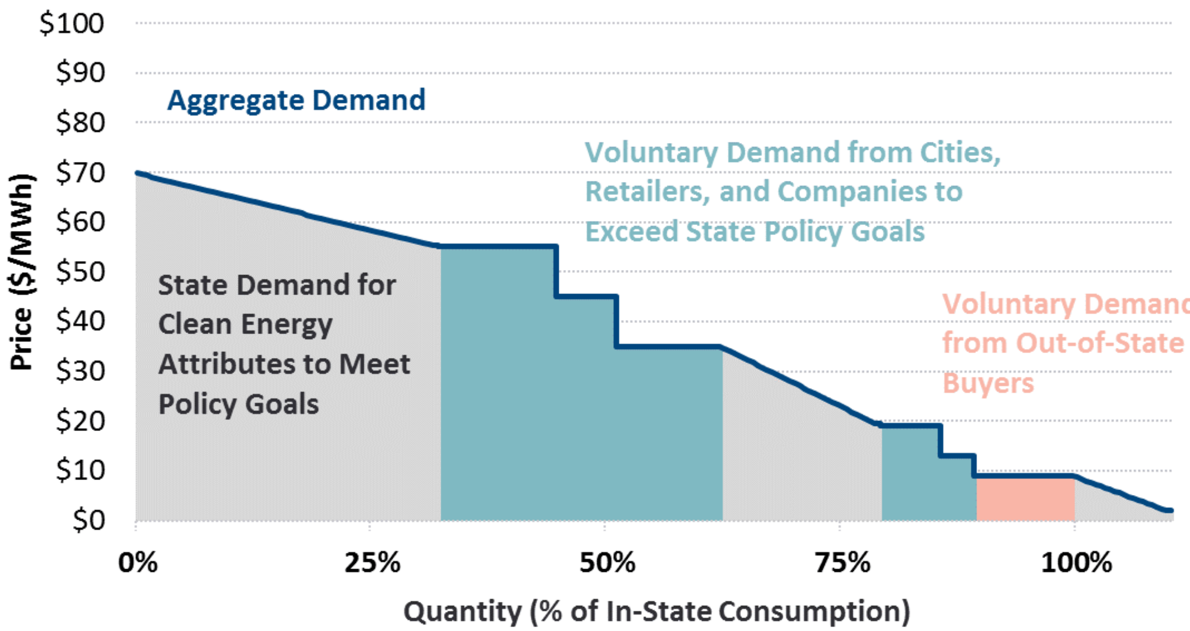
State Demand to Meet Clean Electricity Goals. For states that have policy commitments to serve a certain share of demand with clean resources such as through a Clean Energy Standard, these targets will be straightforward to translate into demand in the forward auction. States that aim to accelerate their clean electricity achievement as long as prices are modest will submit their demand for clean energy as downward-sloping demand curves to purchase higher quantities at lower prices (see Appendix B.2 for a discussion of how to establish demand curve parameters). When the FCEM clears, each state passes on its purchase obligations to LSEs within the state for the delivery period unless those retailers have already made self-supply plans (see Appendix E). States' price points are tied to their level of commitment and maximum program cost tolerance for achieving their clean energy goals. The maximum willingness to pay to displace carbon from the electricity system determines the price cap that states submit.

Tracking System (PJM-GATS), Western Renewable Energy Generation Information System (WREGIS), and Texas Renewable Energy Credit Program (Texas REC).

Voluntary Demand Bids from Cities, Companies, and Retail Providers. Although not required by state law, other entities may want to procure clean energy in addition to state procurements. Companies, retail providers, municipal utilities, and electric co-ops may also participate in the FCEM. These groups are likely motivated by climate commitments, corporate sustainability goals, or providing green energy to end consumers. Voluntary participants submit demand bids solely in the form of price-quantity pairs, reflecting those customers' willingness to pay to purchase each incremental quantity of CEACs.

Total Demand is the horizontal aggregation of all demand bids from states, cities, companies and retailers as illustrated in Figure 4. The demand curve is constructed by calculating the total quantity demanded in aggregate across all customers at each price. The aggregate demand curve would consist of a series of downward-sloping segments (reflecting state procurements under the states' downward-sloping demand curve), intermixed with price-quantity pair segments (reflecting voluntary buyers' demand for CEACs).

Figure 7
Aggregate Demand for Clean Energy Attribute Credits



Note: Demand in this figure is represented as the percentage of a specific state's demand, although the design will maximize benefits if extended to clear supply and demand from multiple states together in the same auction.

2. Expressing State Demand as a Downward Sloping Demand Curve

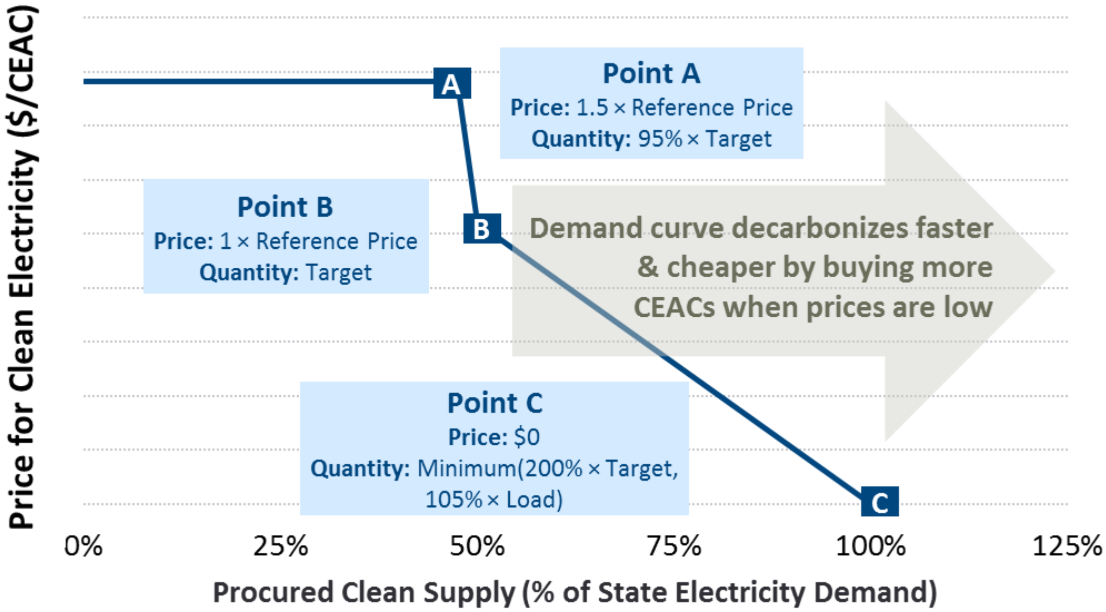
States can use a smooth downward-sloping demand curve to express their willingness to pay for CEACs. There are a number of benefits to using a sloped demand curve. A sloping curve mitigates the year-to-year price volatility as market conditions fluctuate and mitigates potential exercise of market power (see Appendix F). These beneficial price formation properties can stabilize pricing in the FCEM 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. If large amounts of CEACs are available at lower than expected costs, the auction would automatically clear more supply at a lower price to allow an accelerated decarbonization trajectory.

In Figure 8 we provide an example of an illustrative sloping demand curve that a state could bid into the auction. The curve is defined by three price and quantity points that would be updated each year using a formula that reflects a state's willingness to pay to achieve carbon abatement:

- **Point B:** The curve is anchored at "Point B" which is the procurement target at a price equal to the "Reference Price" established based on either the Clean Net CONE, or the Social Cost of Carbon (see additional discussion of these two options below).
- **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 two times the procurement target or 105% of forecasted electricity demand, whichever is lower. 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.
- **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 the Reference Price, at a quantity 5% less than the target. 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 would be 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.

We offer these price and quantity points as 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 never falling 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 Figure 8. 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 the Reference Price, the curve will help meet the carbon objectives while appropriately balancing costs, mitigating price volatility, and supporting a sustainable marketplace.

Figure 8
Illustrative State Demand Curve for CEACs



There are two ways to set the "Reference Price" used to guide price levels in the demand curve: based on the Clean Net CONE or the Social Cost of Carbon. The state or its designated auction administrator would set this price in a predictable fashion and update it periodically. The Clean Net CONE approach is based on the theory that prices in the FCEM should converge to the long-run marginal cost of supply, i.e., the price for CEACs that would be needed to attract additional new clean energy resources into the market. This is the same approach used to set demand curve price levels in wholesale capacity markets. The primary advantage of the Clean Net CONE approach is that it is very likely to achieve the emissions target in each year. The disadvantage is that demand curve may not as accurately represent the social value of carbon abatement. The Clean Net CONE would be calculated as the annualized investment and fixed costs required to build a new clean energy resource, *minus* the revenues that the resource would already expect to earn from the wholesale energy, capacity, and ancillary service markets. The net remaining cost is the CEAC-based payment price needed to attract new clean energy into the market. This cost could be estimated in a bottom-up engineering study every 3-4 years, with formulaic annual updates (as is done in wholesale capacity markets).

An alternative approach for setting the Reference Price would be based on the Social Cost of Carbon, or the state's determination of the value it places on avoiding carbon emissions. Many states have begun to use a Social Cost of Carbon metric for a variety of regulatory and environmental policy purposes in order to provide a common benchmark for establishing which policy measures and investments are (and are not) cost effective to pursue.[16] This approach to setting the CEAC demand curve offers the theoretical benefit of aligning the state's willingness to

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16 Institute for Policy Integrity. States Using the SCC. New York University School of Law. Accessed July 26, 2019.

pay with other policies and with the social benefit of mitigating emissions. The Social Cost of Carbon would be measured in dollars per ton (or dollars per tonne) of carbon dioxide emissions. Table 2 contains the federal estimates for the Social Cost of Carbon that could be used in setting the demand curve and how that value may increase over time. Then the Social Cost of Carbon is translated into a $/MWh rate based on the average marginal emissions rate avoided by a CEAC, and should subtract out any carbon abatement value that clean energy resources are already able to capture under state or federal carbon pricing mechanisms (such as through state cap and trade programs such as the Western Climate Initiative (WCI) or the Regional Greenhouse Gas Initiative (RGGI)). As an example of that calculation, the year 2020 Social Cost of Carbon from Table 2 at $47/ton could translate into approximately $32/CEAC as the Reference Price.[17] This value would be updated each year based on adjustments to the deemed Social Cost of Carbon, the prevailing price in other carbon pricing programs, the most recent data on the average avoided emissions from each CEAC, and inflation.

Table 2
Social Cost of Carbon that Could Be Used in Setting Demand Curve (Real 2019$)

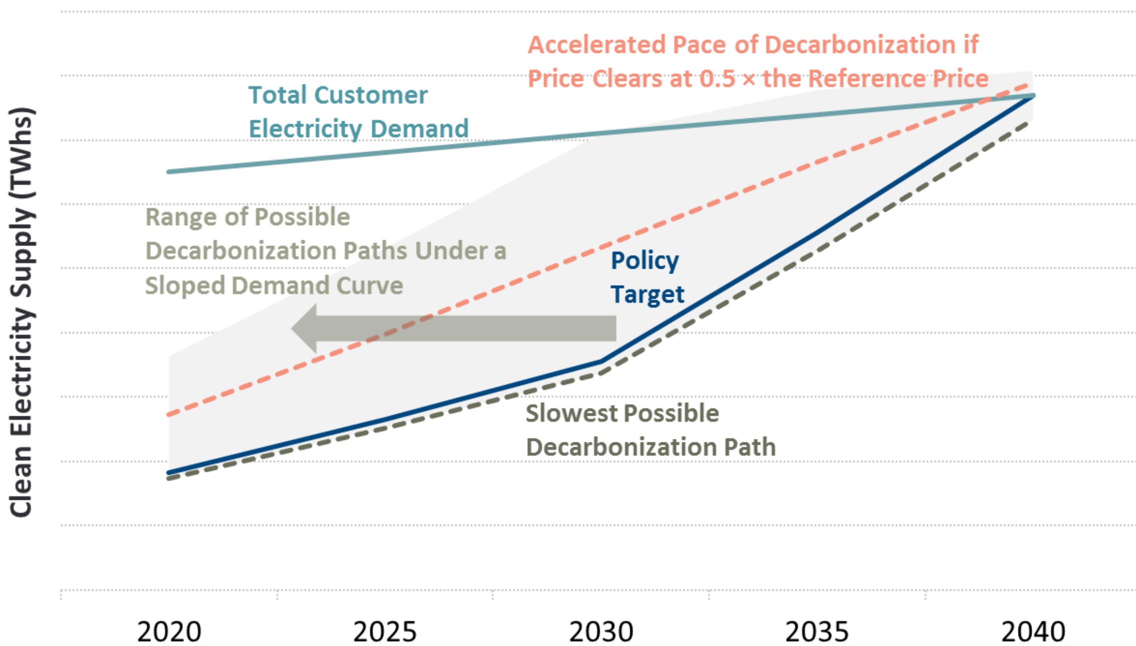
Year	Social Cost of Carbon *($/ton)*
2020	$47.25
2025	$51.75
2030	$56.25
2035	$61.87
2040	$67.49
2045	$71.99
2050	$77.62

Source: Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised August 2016). Table ES-1: 3% Average Discount Rate. Converted from the original 2007$ to 2019$, and from metric tonnes to short tons of carbon dioxide.

The range of possible clearing outcomes from using the above demand curve for CEACs is illustrated as the gray area in Figure 9. If large quantities of CEACs are available at prices lower than the Reference Price, and the market will repeatedly clear to the right of the anchor point and the state will follow an accelerated pace of decarbonization. Under this demand curve shape, there is a significant likelihood of accelerated decarbonization, translating to the possibility of 100% decarbonization as early as 2030 if costs are low enough (even though the state target is 50% by 2030 and 100% by 2040 in this example).

17 Assumes that the cap-and-trade program carbon price is at an illustrative $5/ton and the marginal avoided emissions of 1 CEAC is 1,500 lbs/MWh. The conversion of Social Cost of Carbon from $/ton to $/CEAC is: ($47.25/ton SCC value - $5/ton cap-and-trade price) × 1 ton/2,000 lbs × 1,500 lbs/MWh × 1 MWh/CEAC on average = $31.68/CEAC.

Figure 9
Potential Pathways to Decarbonization with a Sloping Demand Curve
(Example of a State with Clean Energy Targets of 25×2030, 50×2030, and 100×2040)



3. Supply Participation

Suppliers who own or are developing resources that produce carbon-free electricity can offer to sell CEACs in the delivery year at a price they choose. Anyone who can supply carbon-free electricity can participate if they are qualified to do so. Suppliers must provide verification that the resource creates carbon-free electricity, documentation about meeting development milestones, and the ability to meet credit requirements. For existing resources, the quantity of supply the resource is eligible to offer must align with historical output. For new resources, or those with short operational history, the quantity must align with a class average estimated output.

Similar to demand bids, suppliers will submit sell offers in the form of price and quantity pairs representing their willingness to sell CEACs at each price. These offers can be specified as either continuous or discrete offers, allowing for proper treatment of resources with lumpy investment costs (such as an all-or-nothing, go/no-go decision that will apply to an entire asset).

As with demand, the aggregate or system supply curve represents the overall system supply for CEACs at each price, and can be calculated by summing the aggregate quantity available from all suppliers at each price.

C. Centralized Forward Auctions

A centralized auction will bring together demand bids and supply offers into a single market and determine the CEAC price and clearing quantity. This forward auction occurs three years forward, for each one-year delivery period, with FCEM clearing results made available prior to the beginning of the bidding window of the forward capacity auction where applicable. In combination with the capacity and energy markets, the FCEM will support the efficient entry and exit of supply and support financing of new resources.

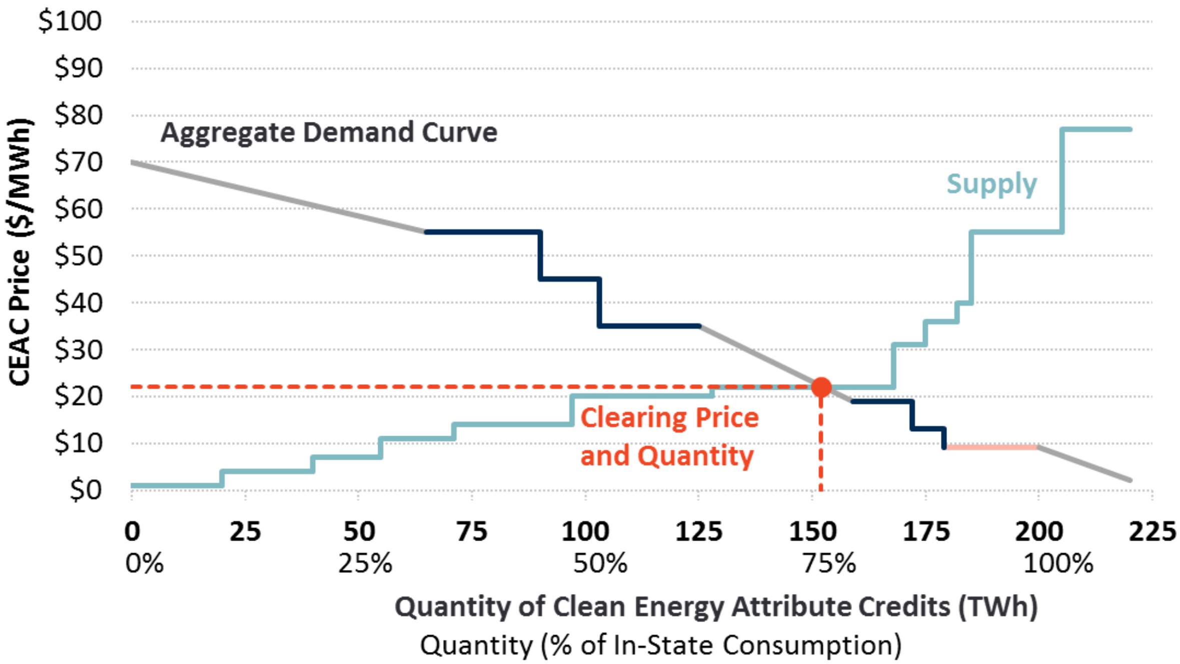
The auction itself could be conducted by an ISO or RTO; a single state (or its designated auction administrator); a multi-state organization; or independent body. The auction administrator would be responsible for collecting demand bids and supply offers, clearing the auction, and tracking CEAC creation, transfers, and retirements. The auction administrator would also be the counterparty for all market activities so as to ensure proper credit requirements and implement settlements.

1. Auction Clearing and Price-Setting

The auction administrator will conduct the forward auction as a single-price, single-round auction. As shown in Figure 10 below, the clearing price will be set at the intersection of the supply curve (comprised of all supply offers arranged in order of increasing price) and demand curve (comprised of all demand bids arranged in order of decreasing price).

The auction administrator will determine which supply offers and demand bids are cleared. All supply that offered below the clearing price will receive an obligation to provide CEACs in the delivery year, and the right to get paid the clearing price for each CEAC. Similarly, all demand bids submitted above the clearing price will be awarded the right to collect a CEAC and the obligation to pay the auction clearing price for their cleared CEACs. Settlements will not be implemented until the delivery year.

Figure 10
Example: Clearing the Forward Clean Energy Market



2. Multi-Year Price Lock-In for New Resources

New resources will have an option to lock-in prices for a pre-specified seven-year term (or some other reasonable pre-specified term). This price lock-in is similar to the new entry price lock-in that is available under the ISO-NE capacity market.[18] Resources that qualify as new and are thus eligible for a lock-in can be awarded the right to the original clearing price for up to seven years.[19] The purpose of such a mechanism is to further support the ability of investors to finance new competitive clean entrants under more attractive terms. These offers will be considered in merit order alongside single-year offers.

Supply and demand that are already matched from prior years' multi-year commitments will be pre-scheduled as cleared into the auction. This is equivalent to having the already-committed supply incorporated as a price taker in the auction (see additional discussion in Appendix H.2). For new lock-in supply offers in each auction, the quantity that is cleared must be no greater than the quantity of state demand in the auction in that year (since voluntary demand bids will not be subject to lock-in terms).

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18 This price lock-in mechanism will tend to reduce competition between new and existing resources, such that it creates an advantage for new and somewhat reduces market competitiveness and efficiency. The primary reason to include a multi-year price lock-in is to ensure financeability of new resources. Over time as the market is demonstrated to be robust and reliable, it may be possible to reduce the term or eliminate the lock in to maximize efficiency.

19 The specific determination of "new" resources that are eligible for the multi-year price lock-in would be determined as part of the detailed market design.

D. Delivery and Performance Obligations for Sellers of Clean Energy Credits

Sellers will be obligated to physically deliver the CEACs that they have sold in the forward auction, either by producing the required quantity of CEACs or by identifying another source of the CEACs. Failure to deliver the CEACs will result in appropriate non-delivery penalties.

1. Physical Delivery and Settlements

Sellers will demonstrate fulfillment of their obligations to produce CEACs by delivering certified CEACs awarded and accrued in their individual accounts from the tracking system to the FCEM administrator on a monthly basis in the delivery year. Excess CEACs produced in any one month will be held in the seller's account to be used for physical delivery in future months or for sale to other entities, through bilateral transactions or in a centralized auction at a later date as described below.

Sellers will be paid monthly at the original auction price based on the quantity of CEACs delivered in each month. As the delivery period is annual, sellers can fulfill their obligation to deliver CEACs in any month of the delivery year; in other words, any monthly deficits in delivered CEACs could be fulfilled and settled in later months in the same delivery year without penalty as long as any shortfall is remedied prior to the compliance deadline (see Appendix D.3).

2. Spot Auction

A final spot auction will be conducted after the end of each delivery period after the final quantity of CEACs created is known, and before the LSE compliance deadline.[20] This spot auction will provide a centralized market for buyers and sellers to transact CEACs after the delivery period. It will help stabilize CEAC prices and provide an opportunity for market participants to meet obligations and manage holdings as needed before the compliance deadline applicable to LSEs. Supply and demand will reflect the following:

- **Supply:** Generators and retail providers ending the year with a surplus of CEACs could sell into the spot auction.
- **Demand:** Generators and retail providers or other customers with a deficit of CEACs could submit buy bids.

This spot auction would be conducted after the delivery year but prior to the LSEs' CEAC compliance deadline. The price cap in the spot auction would be the same as the price cap in the forward auction. This will provide the market a final opportunity to adjust their positions, provide additional price transparency/liquidity prior to the LSE compliance deadline.

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20 The quantity of CEACs created in each year will naturally vary depending on generation from clean resources as associated with factors such as weather conditions.

3. Penalties for Non-Delivery of Clean Energy Attribute Credits

Suppliers that cleared the forward market will have obligations to fulfill CEAC delivery based on their forward sales and will have multiple opportunities to fulfill that obligation. These options include physical delivery through clean generation that results in creation of CEACs, bilateral transactions to purchase CEACs from other entities, and the spot auction.

Any remaining supplier deficiency at the timing of the spot auction will be automatically fulfilled with a mandatory buy-out bid. Such a bid may induce a significant loss or penalty on a supplier in the event that they had cleared at a low price in the forward market but must then buy out of that obligation at a higher price in the spot auction to cover any remaining shortfall. No additional penalty will be assessed on suppliers unable to meet their forward obligations.

4. Banking of Unused CEACs

Excess CEACs can be maintained in account or "banked" one-for-one for use in future years. Any banked CEACs can be used to fulfill future commitments by reducing the quantity that needs to be purchased (by LSEs and other loads) or increasing the quantity that can be sold (by clean energy producers).

This market design component ensures that unused CEACs continue to have value in future years. This helps to stabilize CEAC prices in the FCEM and spot markets, and reflects the underlying long-term societal value from carbon abatement embodied in the CEAC, which is not tied to abatement in any particular year. In this way, we see the FCEM as significantly different from the other wholesale energy and capacity markets they complement. For example, excess energy produced in one year cannot be used to fulfill demand in a following year. This is because the value of energy is tied to the location and time it is produced. In contrast, the value of a CEAC corresponds to a unit of carbon abatement, and atmospheric carbon has a very stable global warming potential over multiple decades. Thus, carbon abated in one year, or an additional CEAC produced in on year, has nearly the same value in the following year, reflected in the one-for-one banking provision.

This provision will apply to market participants on both the supply and demand side:

- Clean energy producers that create CEACs in excess of their forward obligations in a particular delivery year will be allowed to sell them through bilateral transactions or the spot market or bank the credits to sell in subsequent delivery years' forward, spot, or bilateral markets.
- Entities such as LSEs with a customer obligation to purchase and surrender CEACs corresponding to a share of energy consumption may also find themselves with an excess of CEACs if their customers' realized retail energy consumption was lower than expected. These entities will also have the option to roll over CEACs to be used in future years.

E. How Retail Providers Demonstrate Fulfillment of Clean Energy Mandates

Much like with current renewable portfolio standards, states or other policymakers will establish clean energy mandates and require LSEs to fulfill this requirement. In states with retail choice, this means that competitive retail providers will take on the obligation of fulfilling the clean energy mandate. For example in a state that has a 50% clean electricity requirement, retail providers will need to procure approximately 0.5 CEACs for every MWh of retail load the provider serves (plus or minus any adjustment associated with demand curve clearing). Retail suppliers can actively manage their CEAC portfolio on a forward basis or passively accept the outcomes of the centralized FCEM. This approach is analogous to the forward obligations placed on retail providers by centralized forward capacity markets.

On a forward basis, the state will submit demand in the FCEM that represents all energy consumption in the state. The quantity cleared in the FCEM determines the final quantity as a percentage of consumption that all LSEs and competitive retailers must procure on behalf of their customers. For example, if the state target is 50%, but the FCEM clears at a lower price and 52% of the demand curve quantity, then the final obligation on retail providers is 52%. This percent quantity requirement will be held constant through the delivery period. For retailers with a passive approach to fulfilling the clean energy mandate, they will not actively participate in the forward auction (instead allowing the state-developed demand curve to act on their behalf).

During the delivery year, each month a specific quantity and cost obligation from the forward market will be transferred to retail providers, consistent with the clearing outcome from the three-year forward FCEM auction. Because many states have retail choice policies, the quantity of CEACs and obligations applied to each retailer will be adjusted to be consistent with customers that switch providers during the year. This approach reflects the current practice in most capacity markets, where a centralized single buyer allocates costs to retailers or LSEs in a manner that reflects their overall contribution to the need for capacity at the system level. In the same way and using the same daily customer switching data as is used for capacity markets purposes, the FCEM procurement costs will be allocated to individual retail providers and LSEs consistent with their share of customer demand realized in the delivery year.

For retailers who choose to actively participate in the FCEM, there are several options for the retailer to manage their positions and value proposition to customers:

- *Prior to the three-year forward auction*, retailers can choose to engage in a forward contract or self-supply of CEACs. Secured clean energy supply can be pre-scheduled into the FCEM auction and netted out of the retailer's settlement obligations. For example, assume a retailer anticipates 100 MWh of retail load, decides to self-supply 30 CEACs prior to the FCEM, and the FCEM clears with a 52% compliance obligation on retailers. The 30 CEACs of retailer self-supply will be accounted for and netted out of the FCEM cleared quantity; assuming realized retail load in the delivery year remains at 100 MWh, this retailer will be allocated 22 CEACs and the associated costs in the delivery year (the 52 CEACs that would have been procured via the demand curve, minus the 30 CEACs that were self-supplied).

- *After the forward auction, during the delivery year, and before the compliance deadline,* retailers can trade CEAC obligations bilaterally either via short-term contract or through a trading exchange in advance of delivery. The required quantity of CEACs that each retailer is obligated to procure can change up until the end of the delivery year, due to adjustments in customer base (from retail switching), and due to deviations in realized customer demand compared to the three-year forward forecast. However, the percentage of retail load obligated under the clean energy mandate would remain at the same percentage that cleared the forward auction.
- *After the delivery year,* a voluntary spot auction will be conducted to allow retailers and clean energy suppliers to efficiently trade CEACs, as described in Appendix D.2. Retailers can participate on a voluntary basis to offer any excess CEACs held in account for sale into the spot auction, or can hold them to be used in future years. The outcome of the spot auction will not change the retailer's obligated quantity of CEACs.

At the compliance deadline following the spot auction, retail providers and LSEs will need to make a submission to the state demonstrating compliance with the CEAC obligation quantity (possibly via the auction administrator, to simplify the tracking requirements). This deadline will serve the same role as the compliance deadlines applicable under current renewable portfolio standards. The retailer's compliance filing will report total MWh of electricity served, applicable percentage clean energy mandate as established in the forward auction, resulting CEACs submitted for retirement under the mandate, and any additional CEACs submitted for retirement under incremental voluntary green energy offerings. If a retailer submits insufficient CEACs to fulfill its mandate, the remaining shortfall of CEACs will be subject to a penalty defined by the alternative compliance payment (ACP). Unlike in current programs, the ACP will not be defined by a specific pre-determined price. Instead it will be set individually for each retailer or LSE as a function of the size of its shortfall based on the pricing in the demand curve. For example, consider a retailer that is obligated to deliver CEACs to cover 52% of its realized customer demand but only surrenders enough CEACs to cover 48%; the ACP on the retailer's 4% quantity shortfall would be defined by the demand curve price in $/CEAC that would have prevailed if the entire market had cleared at a 48%. This ACP creates a penalty that encourages retailers to fulfill their obligations, with increasingly high penalties (up to the FCEM auction price cap) for anyone that would fall short of their obligation. This mechanism will also support pricing stability in the bilateral and spot markets, and avoid "end price effects" that can sometimes produce price spikes or fallout as the compliance deadline approaches.[21]

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[21] Note that in a market with no banking and a fixed ACP at say $100/CEAC, the market would tend to converge to one of two pricing extremes at either $0 or $100/CEAC as the market came to realize if the aggregate quantity of CEACs is slightly in excess or slightly in shortage. This sort of volatile, bimodal pricing is not helpful in a market intended to value the long-run societal value of displacing carbon emissions, which once emitted will remain in the atmosphere at a relatively stable level for many

F. Market Monitoring and Mitigation

The FCEM will include a framework to mitigate market power and ensure outcomes are as competitive and efficient as possible, similar to other electricity markets.

We anticipate that the FCEM should not be very susceptible to the exercise of market power except in select circumstances. This is primarily because we expect the auction to have relatively flat supply and demand curves, meaning that it would be very challenging for any one large player to gain enough market share to profitably exercise an economic or physical withholding strategy. The demand curve will likely be relatively flat because states may wish to procure large quantities of CEACs beyond the state target if prices are low; voluntary demand bids will further flatten the demand curve. The supply curve will be relatively flat due to the market design with a broadly competitive, open market that can enable many different types of supply resources. Enabling competition from out-of-state clean resources (which is already allowed under most state renewable standards at least for other supply within the same RTO region) will enable a broad range of regional players to compete to identify the least cost projects from a large multi-state region at the lowest cost. Further, the ability to carry over supply of CEACs through banking will create an additional buffer to pricing that will prevent price spikes from the exercise of market power in any one year. Thus, we expect the design of the FCEM combined with a broadly competitive and open market to naturally limit opportunities for the exercise of market power.

Despite these mitigating factors, both buyers and sellers in any auction may have the ability and incentive to exercise market power in select circumstances.[22] In those instances, the FCEM would apply targeted measures that have been demonstrated to mitigate the potential for exercise of market power. In the FCEM, an incentives test would be used to determine how large a net long position an individual firm would need to have before they would be deemed to have the incentive and ability to profitably withhold. Any firm failing that test will be subject to an offer price cap on their existing resources, consistent with net going-forward costs (drawing on methodologies already established in the capacity markets, even if the FCEM is administered by a non-RTO independent body).

Finally, the FCEM auction administrator or market monitor would conduct annual monitoring and mitigation analysis and reporting evaluating the competitiveness of each forward auction, spot auction, and bilateral market activities leading up to the compliance deadline. The report will also

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decades. The introduction of CEAC banking, the variable ACP, and the downward-sloping demand curve together will support more pricing stability across time so as to better support investment decisions and better reflect the stable underlying environmental value of the CEAC attribute.

22 For example, we anticipate this would be most likely in cases where competition is limited or segmented, for example by excluding certain resource types by location, technology, or vintage. Another example would be if one individual company owns a very large share of all existing clean energy within a state (and again, this is mainly a problem only if out of state resources are not enabled to compete).

assess whether there could be any need for additional mitigation measures or other changes to market design to address issues identified.

G. Alignment with Wholesale Electricity Markets

The FCEM would improve alignment with existing wholesale capacity, energy, and ancillary service markets. A marketable product reflecting just the non-emitting attributes of qualifying sources perfectly complements existing wholesale electricity markets for energy and reliability attributes. This allows the combined market forces to identify the least cost bundle of resources to meet multi-attribute system needs. This concept is grounded in a mechanism that has been proven to be effective: electricity generators already produce multiple marketable attributes, including energy, capacity, and various ancillary services. The existing wholesale electricity markets incent entities pursuing private profits to make investment and operating decisions that maximize the system value they provide across these multiple products. Adding a non-emitting resource attribute to the bundle of products that can be sold will incentivize all market participants to identify the best resources to jointly supply both traditional grid services and the demand for non-emitting supply.

1. Energy, Ancillary Service, and Other RTO Markets

The FCEM and unbundled CEAC approach will significantly improve alignment of state polices with wholesale energy and ancillary service markets in several ways. These benefits are primarily achieved by reducing the scope of clean energy policies to pay *only* for the clean value on an unbundled basis (and leaving the wholesale electricity markets to reward other benefits that the resource may offer to the system). As a result, benefits will accrue including:

- Lower clean energy program costs,
- Focusing clean energy program payments through the FCEM on those resources that displace the most carbon (this benefit will be significantly amplified under the "dynamic" CEAC approach discussed in Appendix H.1 below),
- Maintaining full incentives from the energy markets to attract resources with the most advantageous energy output profiles to meet net system peak needs (as well as to operate these resources in ways that maximize energy value),
- Maintaining energy market incentives to locate in the locations where supply is most acutely needed and where transmission congestion can be avoided (thus reducing energy prices and reducing the need for transmission upgrades),
- Maintaining full incentives from the ancillary service market to attract and operate resources that can provide a variety of reliability services to the grid,

- Reducing or eliminating the incentives for resources to offer at negative prices into the energy market.[23] Many types of clean energy payment mechanisms incentivize negative offer prices in the energy market which can be problematic from a customer cost perspective because it implies that a clean resource will be paid to produce power even at times when the supply creates negative value to the grid and when it can only be absorbed by curtailing other clean resources in the same sub-region.

In other words, the unbundled CEAC approach mitigates or eliminates several friction points that have historically existed between markets and bundled all-in procurements and feed-in-tariff (FIT) approaches. The FCEM and unbundled CEAC approach eliminates these challenges by streamlining payments to reward sellers only for their contribution to meeting the defined policy objective. To the extent that the resource can also provide other valuable grid services as well, those can be monetized and rewarded through existing market structures.

2. Centralized Capacity Markets

The FCEM will also be well-aligned with the centralized capacity market construct used in many regions. Similar to the benefits of unbundling the CEAC from energy and ancillary service markets, the CEAC-based revenues will also be unbundled from the capacity market value. This will allow states and customers to pay only for the defined policy objective within the FCEM, and leave the capacity markets to ensure that reliability needs at peak time are served. Clean resources with relatively small capacity value (like wind and solar) can value-stack across these markets but may enter primarily as a play for green value and energy value. Clean resources with significant energy and capacity value (like hydro and nuclear) may earn revenues that are split more evenly across the various markets. Demand response may earn most money from the capacity market; storage may earn most money from energy and capacity (with green value expected more abundantly in future years if many more clean energy curtailments would be expected). Thus, the overall investment incentives for each resource type will be based on how meaningfully that resource contributes to each system need.

Another important issue in several electricity markets today is the "out-of-market" treatment of resources that receive payments for clean energy attributes. The FCEM, with no reliance on carve-outs, would entirely address this issue. The FCEM would be conducted prior to and separately from the capacity market. Then, clean energy payments for resources cleared under the resource-neutral, competitive, market-driven "base" product would be considered "in-market" for purposes of interfacing with the wholesale capacity market. As a result, they should not be subject to any capacity market MOPR provisions.

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23 Note: if the CEAC is designed similar to a traditional REC, the incentive will be reduced in scale to match the size of clean energy payments (rather than the total resource cost). If the CEAC is designed following the "dynamic" approach, then there will be no incentive to offer at negative prices. In both cases however, other programs such as the production tax credit (PTC) could continue to incentivize negative offer prices.

In the long term, the capacity market, energy market, ancillary markets, and FCEM would together drive the most cost-effective investment choices in each region. In regions where a subset of the customers are aiming for deep decarbonization, the capacity markets (as combined with energy and ancillary markets) likely will continue to attract fossil-fuel plants; however the total quantity of fossil plants developed and retained will decline based on the share of capacity needs met by clean supply. In comparison, other regions where most or all customers aim for deep decarbonization, the capacity and energy markets will no longer produce prices that are high enough to attract or retain fossil plants. In those regions, the quantity of clean energy resources developed will be large enough to dominate the energy market (reducing energy prices and displacing fossil plant dispatch) and large enough to meet the majority of capacity needs. In that scenario, the capacity prices required to attract a natural gas plant would be relatively high, so that gas plants would be out-competed by lower-cost resources in the capacity market (such as demand response, efficiency, storage, or clean generation). In the end, capacity prices may be lower than today (especially in the near term before fossil plants retire), or higher than today (if the cost of meeting all capacity needs without fossil plants is relatively high). In either case however, the capacity market can reflect adequacy needs at peak, and work together with the FCEM to guide the market to invest in the most cost-effective portfolio of clean energy resources.

H. Optional Design Elements

As we have discussed throughout this paper, we view this FCEM design proposal as a comprehensive approach to meeting large carbon objectives at the lowest possible cost. However, there are many differences in the regulatory context across different regions that will require various refinements or adjustments to this design. The following appendices describe three design variations that we anticipate may be necessary or useful in certain cases:

- **Dynamic Clean Attribute Credits:** This design option offers an enhanced product definition that awards differentiated quantities of CEACs to different suppliers in proportion to their realized carbon abatement. We would recommend adopting the dynamic CEAC given that it is more economically efficient than the simpler CEAC product definition described above; we offer it as an option mainly because it is more complicated and so may take more time to implement. The concept of a dynamic CEAC will become increasingly important as regions become highly decarbonized, since an increasing share of the incremental clean energy may need to be focused in specific times or locations to have material carbon abatement value.
- **Grandfathering Arrangements for Pre-Existing Contracts:** Most regions aiming for deep decarbonization goals will be starting from a place with some pre-existing commitments and programs. We offer relatively straightforward approach for grandfathering existing programs to ensure pre-existing commitments are honored while still enabling the sector to transition toward the fully competitive, all-source approach under the FCEM.
- **Technology-Specific Carve Outs:** The above design does not yet contemplate the possibility that a state may require carve-outs for specific quantities of targeted resources. This design variation offers a clear way to integrate targeted resource carve-outs into the FCEM design described above (although these will by their nature somewhat reduce the level of cross-technology competition).

The following subsections provide additional description of these specific design variations that we anticipate will be desired or needed in certain regions.

1. "Dynamic" Clean Energy Attribute Credits Awarded in Proportion to Delivered Carbon Abatement

If the objective of state clean energy policies is primarily carbon abatement, an enhanced version of the CEAC product definition can be adopted to focus exactly to this objective. As discussed in Appendix A.1, a more economically efficient CEAC product definition would define each credit in proportion to tonnes of carbon emissions abatement rather than one CEAC corresponding to one MWh of clean energy generation. This CEAC would represent a constant and uniform quantity of emissions abatement, based on the quantity of carbon dioxide displaced by each marginal MWh of clean electricity supply injected into the grid at a particular time and place. This definition would more flexibly and accurately account for the carbon abatement value of different resources, which varies depending on their location and time profile of generation (both of which affect the carbon emissions they can displace). This alternative product definition, which we call a "Dynamic" CEAC, can also reward and incentivize storage and other resources that have carbon abatement value but that would not be compensated under the simple CEAC definition described in the body of this proposal.

The quantity of Dynamic CEACs created by each resource would be calculated as:

$$\text{CEACs} = \text{Physical Generation} \times \frac{\text{Realized Abatement Rate}}{\text{Standard Abatement Rate}}$$

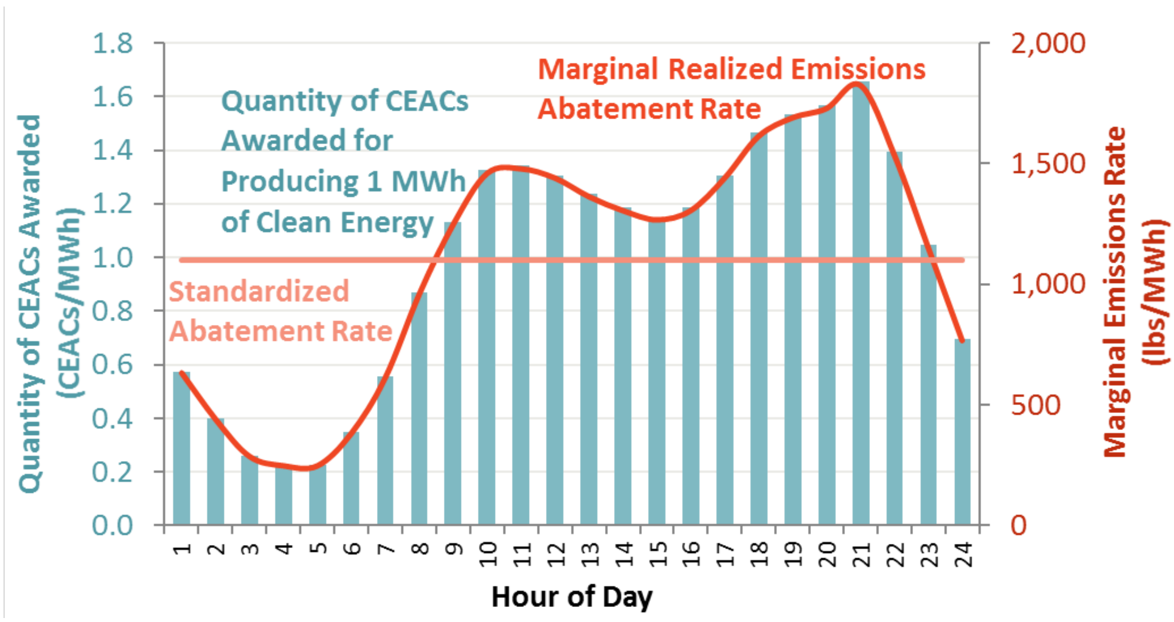
This equation yields the quantity of CEACs created by any particular resource given the resource's physical generation and information about the marginal emissions rate of the system when and where the resource generates electricity (and displaces carbon-emitting resources). The components of the calculation are defined as follows:

- **CEACs** are the total annual quantity of CEACs created by and awarded to the resource owner. The rate of CEACs awarded per physical MWh produced may be greater than the average across all clean suppliers (if the resource displaces primarily coal generation) or less than the average across all clean suppliers (if the resource displaces primarily other clean resources).
- **Physical Generation** is the MWh produced by the clean energy resource as metered and injected to the grid.
- **Standardized Abatement Rate** is the standard quantity of marginal carbon displacement required to produce one CEAC. This standardized abatement rate will be established prior to the forward clean energy auction and known to all participants in advance of submitting any offers. It will be established based on the marginal emissions displacement delivered across the entire fleet of clean energy resources as measured in the tracking system over the past three years, with the parameter updated annually. An example is 1,100 lbs of CO_2/MWh.
- **Realized Abatement Rate** is the measured marginal carbon abatement value by the specific resource in question, based on the time and place where the clean energy was injected into the grid. The realized carbon abatement could be much higher than the standardized rate (e.g. 1,900 lbs/MWh, if the resource is primarily displacing coal generation) or much lower than the standardized rate (e.g. down to 300 lbs/MWh, if the resource is in an export-constrained wind pocket where injecting more supply is primarily displacing other wind generation). The realized abatement rate will be calculated using RTO data on resource-

specific 5-minute injections into the grid at a particular node, and the marginal carbon emissions at each node of the power system in each 5-minute nodal pricing interval.[24]

The CEAC tracking entity will be the one to collect the physical generation and RTO marginal emissions data, and calculate CEACs to be awarded to each clean resource. Figure 11 illustrates how the quantity of CEACs awarded will vary by hour as the marginal emissions rate at a particular location in the system changes, highlighting the direct relationship between the CEACs awarded and the carbon abatement value of that clean generation in all hours. Because more CEACs will be created during high-emissions hours, higher payments (i.e. quantity of CEACs times the price earned from each CEAC) will be earned by resources injecting power during those intervals.

Figure 11
Illustrative Quantities of CEACs Awarded in a Representative Day
For a Resource Producing 1 MW of Power in a Flat Output Profile



This "dynamic" CEAC product design introduces several efficiency advantages relative to the simplest 1 CEAC per physical MWh design described in earlier sections. First, the incentives and

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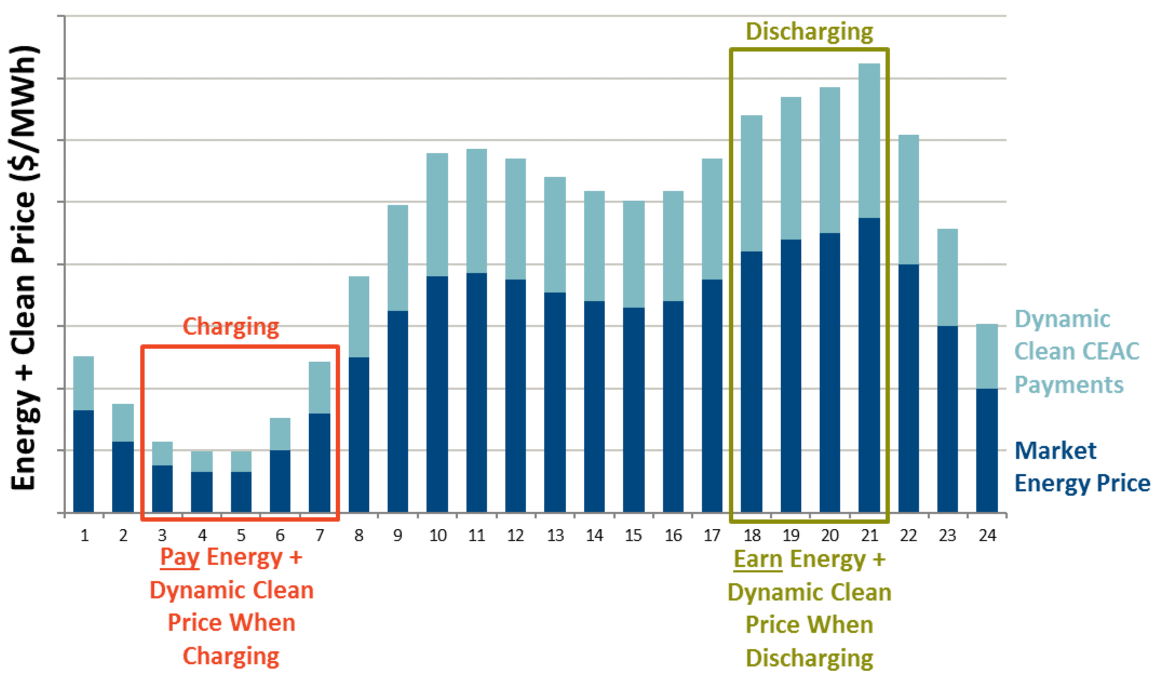
24 In ISO-NE, the marginal carbon dioxide emissions rate across all hours in 2017 was calculated to be 654 lbs/MWh, which was 22% lower than the estimate for 2016. To calculate the marginal emissions rate, ISO-NE starts by identifying the locational marginal unit for each 5-minute interval within its energy market dispatch software. Then, ISO-NE multiplies that generator's average emissions times the percentage of intervals for which it was marginal. The sum of these products is the average marginal emissions rate for the entire system across all pricing intervals. ISO-NE separates out this calculation on a peak and off-peak basis in regular reports, and has separately reported hourly real-time emissions rates. The same method can be extended to calculate the marginal emissions rate at each node in the system alongside the calculation of the locational marginal price (LMP) which is also calculated as a function of the marginal resource at each location. See [2017 ISO New England Electric Generator Air Emissions Report.]

payments to clean resources are proportional to the marginal carbon emissions across both time and location, so this approach rewards resources with greater carbon abatement value and focuses incentives for both investment and operations toward those resources that will achieve more carbon abatement faster. Second, a dynamic CEAC removes the incentives for generators to offer into the energy market at negative prices and to over-saturate wind rich locations, as can occur with traditional REC, feed-in-tariff (FIT), and production tax credit (PTC) incentives. Finally, this will fully enable storage resources to participate and displace carbon emissions if they can store low-carbon electricity and discharge that power when the marginal abatement value is high.

Although storage resources do not generate clean energy, they still have a carbon abatement value that will be recognized through the Dynamic CEAC. Most storage resources will not charge exclusively using carbon-free energy. Thus, every MWh of electricity released from a storage resource has some "embedded" carbon emissions that reflect the incremental carbon emissions from the resources on the margin when the storage was charging. However, it is likely that this embedded carbon is still lower, on a tonne per MWh rate, than the marginal emissions rate when the storage resource is discharging (because higher prices when discharging generally correspond to higher emissions rates). Thus, storage resources can reduce carbon emissions by allowing low-carbon energy generated in one hour to displace high-carbon energy generated in another. Further, incorporating storage resources into a Dynamic CEAC program will create incentives for storage owners to operate their assets in a way that maximizes carbon abatement value. The mechanics of how the dynamic CEAC approach can enable storage to participate on a fully resource-neutral basis with other clean energy resource types is illustrated in Figure 12 and described in detail below.

Figure 12
Illustration of Storage Participation with Dynamic CEACs



In the existing electricity markets, storage resources pay the energy price to charge in low price hours, and earn the energy price to discharge in higher-price hours (dark blue bars). In the dynamic CEAC approach, they will also pay the cost of buying CEACs when charging to cover the incremental carbon emissions that the storage asset has imposed on the grid (aqua bars). If the storage asset charges during a high-carbon hour, the cost of CEACs will be quite high; conversely, if charging during an hour with only solar and wind generation, the storage asset will pay nothing for carbon emissions. When discharging, a storage asset is paid the energy price to inject power into the grid plus it will earn revenues from selling any CEACs it creates. Discharging in hours with very high emissions means that storage will be paid more. A storage asset can maximize its CEAC-derived value by absorbing wind or solar power that would otherwise be curtailed, and reinjecting power at times when displacing coal generation. When deciding on the output profile, the storage resource will consider the best way to maximize its value to the grid considering: (a) energy value, (b) ancillary service/flexibility value, and (c) carbon abatement value. That way, storage can continue to play a major role in providing both essential grid and flexibility services as well as assisting to decarbonize at the same time.

2. Grandfathering Arrangements for Pre-Existing Contracts

Some states or utilities may have already made long-term commitments to clean energy suppliers, and it would be improper to provide additional compensation to these suppliers for clean energy they have already contracted to sell. Providing payments above those specified in the existing contracts would amount to double payment for clean energy attributes, which would increase customer costs. Instead, these contracts can be grandfathered into the new FCEM and continue receiving their contracted payments until the end of the contract term.

For example, a state may have already contracted for 20% of supply under existing long-term commitments to purchase renewable energy. In this case, the quantity of CEACs produced by the already-committed resources would be scheduled in to the FCEM as “self-scheduled” supply. These CEACs will reduce the remaining quantity of supply to be procured through the FCEM to meet policy goals. On the supply side, these resources’ CEAC production would be accounted for as contributing to state needs but the asset owners would not be paid the FCEM clearing price. As existing contracts expire, those resources would be rolled into the broader market and could compete with other existing and new resource to provide CEACs at the most competitive price.

3. Technology-Specific Carve-Outs

In some cases, states may wish to pursue complementary policy objectives and desire to procure a specific type of resource rather than the lowest-cost resources. Incorporating such carve outs will increase the costs of achieving a state’s policy goals, but may be required by policymakers for other reasons.[25] In this case, a variation of the FCEM design can be used to simultaneously achieve both the total clean energy goal and the technology-specific carve out. The same design can be used to achieve multiple carve out targets for multiple types of targeted resources, although we caution against introducing large quantities or many types of carve outs as these will tend to segment the market, limit competition, and increase cost. Thus, if policymakers wish to contain the costs of achieving the clean energy goal, we recommend limiting the quantity, number, and term of carve outs. For example, if policymakers wish to support the local industry for a specific technology, they could do so through a modest-sized carve out designed to incent early investments with a phase-out over a reasonable timeframe (after which the technology would need to be cost-competitive on its own and compete on a level basis with all other supply types).

For a state that wishes to ensure a certain technology carve-out is achieved, the FCEM will be designed to define two types of resources:

- **Base resources** will include all types of supply resources that can produce CEACs (including both targeted and non-targeted resource types). Base resources that clear the auction will be composed of the least cost clean supply, with no restrictions by type, location, or resource age. The clearing price for base resources will be the lowest possible price at which customers can meet their clean energy goals.
- **Targeted resources** allow states to carve out a portion of the demand and ensure that it is met by a specific type of technology such as in-state solar, offshore wind, or batteries. These resources will clear in a separate sub-auction, where price separation will allow for higher prices to be awarded for targeted resources. A higher price will be produced for targeted resources only if that higher price is necessary to bring the preferred resource types online (otherwise, if the targeted resources are cost-competitive with other resources they will clear at the same price as base resources and will clear in a quantity at or above the carve out).

To minimize the cost and less competitive nature of a carve outs approach, we recommend limiting the applicability to only apply to new resources of that technology type, limiting the quantity of carve outs to no more than 5% of total demand in the FCEM if possible, limiting the application to specific situations where there is an expectation that the technology can eventually become cost competitive with other supply types, and phase out the carve outs over a sunset period when the technology is anticipated to become more economically competitive.

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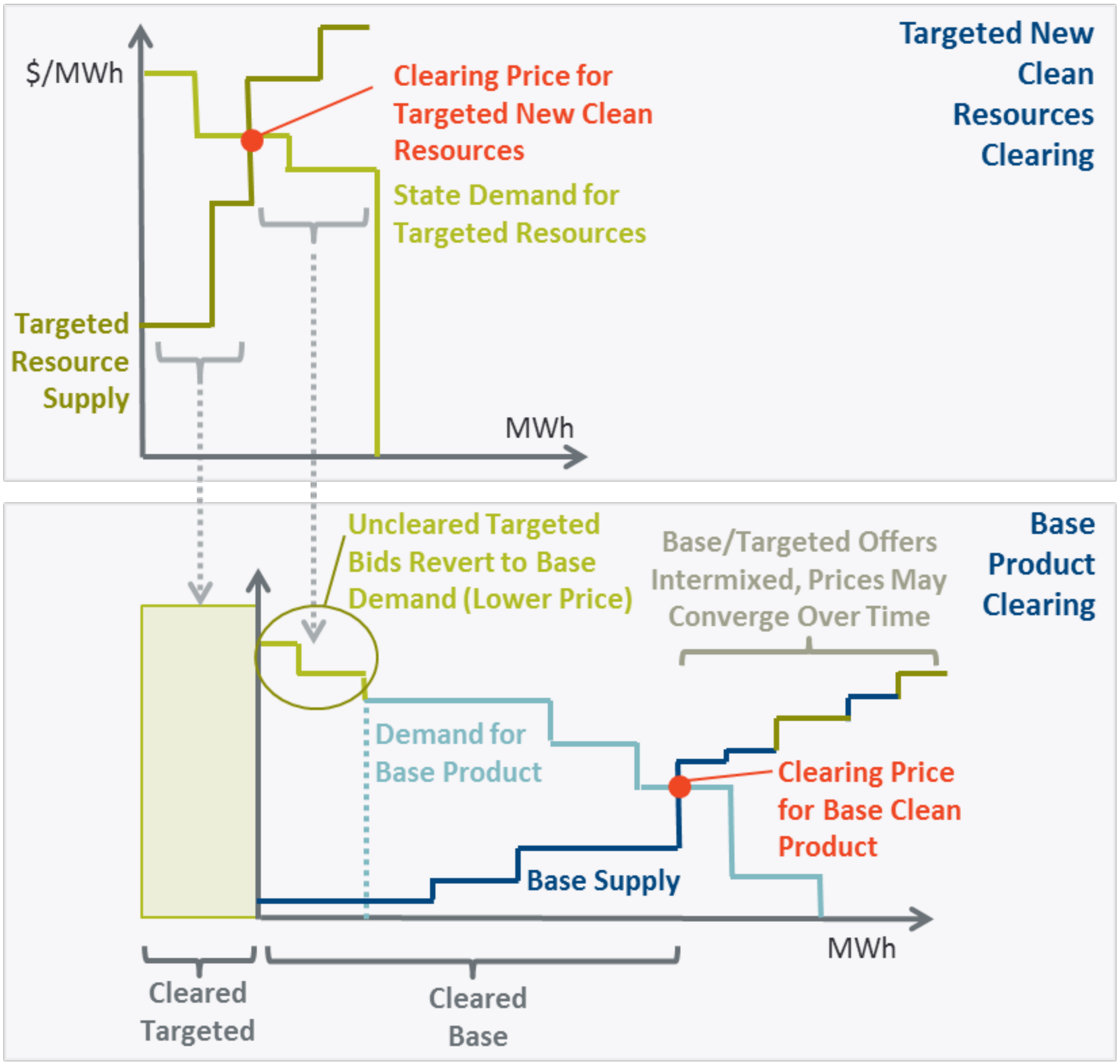
25 Carve outs necessarily increase program costs by requiring that a certain share of the total mix of clean resources come from a specific technology type such as offshore wind, from a specific location such as in-state locations, or class of developments such as small/residential solar. If these resources were among the least-cost projects, they would naturally be developed by the marketplace to meet total demand (and thus no carve-out would be needed). However, carve-outs are usually introduced as a means of supporting a technology that would not otherwise be cost-competitive due to the higher cost as compared to alternatives.

When implementing the carve-out for targeted resources, states or customers would specify this as a preference in their demand bid. For example, a state could submit its demand as a quantity of base and targeted resources (e.g. as 50 TWh of clean supply, of which at least 2 TWh must be from storage). The demand bids can be submitted at different prices if the state is willing to pay more for the targeted resource type. The targeted resource carve-out bid can also be treated as "contingent" in that if no storage is available at or below the maximum willingness to pay, the demand will revert to procuring the same quantity from the "base" product. This contingent bid approach allows a state to support targeted resources as long as the price is reasonable, while also ensuring that the total clean policy goal will be achieved even if the targeted resources are deemed not cost effective enough.

Pricing for targeted resources could be equal to or higher than base resources as illustrated in the clearing example in Figure 13 below. This clearing example shows the state demand for targeted resources (top panel), with the sub-auction for targeted resources clearing half of the demand at a targeted resource price. The uncleared demand for targeted resources reverts to demand for "base" resources (bottom panel). A larger quantity of base resources clears at a different, lower price.

This same mechanism allows targeted resources to exceed their carve out quantities to the extent that those resources are more cost-competitive than other technologies. In that case, the auction would clear a quantity of targeted resources in excess of the carve out, and the targeted resources would clear at the same price as base resources.

Figure 13
Illustration of Auction Clearing with Targeted Resources



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