Comments of New Jersey Conservation Foundation on 2022 Progress Report on New Jersey's Resource Adequacy Alternatives Docket # EO20030203

New Jersey Conservation Foundation (NJCF) respectfully submits the following comments on the above Progress Report (Report). These comments are based in part on the attached policy analysis, which is included as part of these comments, of the Clean Capacity Credit Purchase Obligation recommended in the Report. The policy analysis was prepared at the request of NJCF by Steven Corneli. Mr. Corneli has broad experience and academic training in markets and market design options for electricity, environmental commodities, and both mandatory and voluntary carbon markets, and in applied policy analysis of such markets. He has previously participated in this docket, commenting on the merits of the FRR, the FCEM concept and potential problems with the more complex ICCM concept.

NJCF deeply appreciates the BPU and its staff's efforts to advance clean energy and support the more rapid achievement of deeply decarbonizing New Jersey's use of electricity and the expansion of that use to displace other fossil fuels in buildings and transportation. In particular, NJCF welcomes the Report's recommendations in part III. B. that New Jersey should develop a regional voluntary clean energy market. NJCF supports a well-designed regional procurement market for Clean Energy Attribute Credits (CEAC), that represent one megawatt hour of generation from any generating resource that emits zero greenhouse gases (GHGs) from its generation of energy, and that settles its generation in the PJM energy market.

Such a procurement market, however, only would makes sense if New Jersey has a mandate that a growing share of the electricity sold to final users in the state must be purchased from such resources, as demonstrated through the retirement of one CEAC by each load-serving entity for every megawatt hour sold in the state, above and beyond the amounts currently represented by various credits representing zero emission generation of one megawatt hour, purchased by or paid for by the LSE, such as SRECs, ORECs, TRECs and ZECs, that are required by current law. NJCF's view is that such a mandate should be for 100 percent of retail sales, grossed up for transmission and storage losses, to be from zero-emitting generation sources by 2035, as demonstrated through the retirement of one CEAC or one of the above other existing state-mandated credits.

We also firmly agree with the reasoning put forth in Section III. B. of the Report, namely that such a mandate and procurement market would provide significant additional benefits – most notably, greater affordability of clean electricity -- to both New Jersey and the entire region, not interfere with PJM's assurance of significant reliability while growing the clean energy economy, and will lead to greater reductions in the GHG emissions responsible for the rapidly intensifying climate crisis. In addition, NJCF remains broadly supportive of the general Forward Clean Energy Market (FCEM) concept, provided it is not balkanized to the point of inefficiency by various one-off local or technology preferences and other restrictions by various participating states.

The Report also suggests, in part III. E. 3, that existing New Jersey law gives the BPU ample authority to create a regional FCEM and to promulgate a more aggressive mandate than the RPS specified in the Clean Energy Act of 2018 and its various modifications in the past four years. NJCF supports efforts to provide even clearer legal authority and a firm mandate for 100% clean retail sales by 2035 via legislation. The legislature is at this time considering establishing a Clean Energy Standard that may have many of the features identified above and that could be supported by an FCEM, similar in key features to that broadly outlined in the Report. Accordingly, we urge the BPU to weigh in favorably on this legislation to create a mandate with the general features above and authorizing the Board to develop a regional clean energy attribute procurement market, consistent with proven and well-considered market design principles.

NJCF is confident that such a CES and associated clean energy attribute market can succeed, in large part because of the demonstrated track record and established accounting and compliance infrastructure of the regional REC market. Confidence also is merited because of the growing commercial deployment of wind and solar resources across much of the PJM footprint, and indeed around the world, which amply demonstrates that many of the resources that must be deployed to meet a CES have low costs and will readily respond to the opportunity to meet a higher CES mandate in New Jersey. In the technical terms of Mr. Corneli's attached analysis, which also addresses this expected low-cost response to a growing RPS or CES, the supply of resources capable to meet a higher mandate for clean electric energy is "highly elastic." This characteristic helps ensure that such a forward clean energy attribute market will be able to provide compliance credits for even an aggressive CES in New Jersey at a low and reasonable overall cost.

The same confidence in a low cost, affordable and ready to build supply, however, is unwarranted for the other major new idea in the Report, namely the recommendation that New Jersey favor, and mandate, procurement of "clean capacity attributes" to meet a substantial and growing share of the capacity obligation PJM allocates to New Jersey's LSEs. For example, unlike with renewable energy credits (RECs), there is no track record of a "clean capacity attribute credit" ever being successfully created, accounted for, or traded, and no track record of an obligation to cover a share of PJM-cleared capacity with such credits working to increase investment in clean capacity resources. Instead, as Mr. Corneli's analysis shows, there are a number of potentially serious design problems with the proposal, which are likely to prevent it from working as intended.

Chief among them is that, as the amount of wind and solar on the PJM system grows, the amount of capacity PJM will certify for each nameplate megawatt of wind and solar capacity will decrease dramatically, due to the declining contribution these resources will be able to make to avoid reliability threats associated with high demand and low renewable supply during extended periods of extreme weather. The decline in the amount of capacity available from offshore wind, solar and charged batteries at such critical times will become increasing evident through PJM's recent tariff revision requiring the use of an effective load carrying capability (ELCC) methodology to determine the actual UCAP provided by each additional megawatt of such resources. A 2021 study by PJM of the impact of ELCC ratings suggests solar real capacity contributions may decline, relative to current ratings, by 74% for solar, and by 60% for offshore wind, when fifty percent of PJM's energy comes from renewable sources. (See the Corneli Policy Analysis at footnote 11.) Future modifications to PJM's ELCC methodology, to make it more accurate, would very likely result in even larger decreases in the rated capacity of such resources.

Accordingly, the relatively large amounts of offshore wind and solar power that that might today appear to be good candidates for meeting the Report's proposed Clean Capacity Credit Obligation (CCCO), will see the amount of capacity they can really provide shrink dramatically over the coming decade or two.

This problem, plus the inherent difficulty and high cost of developing a significant amount of any kind of capacity, much less non-emitting but firm capacity, in the constrained Locational Delivery Areas (LDAs) -- as would be required under the CCCO proposal, combine to make the future supply of new resources to meet the proposed clean capacity obligation very uncertain.

Mr. Corneli's analysis suggests that supply is likely to be "highly inelastic", meaning that even very high prices in the proposed CCCO market would fail to attract significant investments needed to meet the mandated clean share of capacity. The combination of a mandate to purchase attributes from resources that are difficult or impossible to develop enough of to meet the mandate is a recipe for persistent high prices for consumers, windfall revenues for existing resources, and little or no additional investment that results in real, additional or cost-effective incremental reductions in GHGs or improvements in reliability.

For these reasons, as well as the additional risks and problems with the CCCO concept identified in Mr. Corneli's attached analysis, NJCF does not support either implementation or further development of the concept of mandating the purchase of clean capacity credits. Instead, NJCF would point out that the potential use of dynamic credits in a CES market, where the quantity of credits assigned to each clean resources is a function of its marginal displacement of fossil generation over time, could achieve many of the goals of the CCCO program with much less risk, and without the need to create an entirely different market that poses as many risks of failure as the CCCO idea may inherently entail. In addition, more targeted incentives, focused on incremental clean energy production and displacement of fossil emissions in constrained delivery zones of New Jersey, could achieve many of the locational and technology goals of the CCCO at a much lower cost to consumers, without the risks of a CCCO market creating substantial windfalls for existing resources without attracting new resources.

Regarding the Reports update on the ICCM and FRR concepts, NJCF appreciates and supports the recommendation to not pursue either at the state level, in the absence of the MOPR restriction on state-sponsored clean capacity resources. An ICCM or FCEM implemented by PJM as part of its market authority would, in our view, entail unwarranted and unacceptable risks of federal jurisdiction over the participating states' clean energy procurement and mandates, and should not be pursued. The only alternative to such jurisdictional capitulation that we see for implementing the ICCM would be an FRR, and we continue to not support an FRR due to its inherently higher costs and the risk of even higher costs due to unleashed market power. An FRR should only be considered if a future FERC misuses the MOPR by FERC to materially undercut state achievement of clean energy goals.

A policy and economic analysis of the proposed Clean Capacity Obligation

Prepared for New Jersey Conservation Foundation
by
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Strategies for Clean Energy Innovation

1. Overview. The 2022 Progress Report on New Jersey's Resource Adequacy Alternatives ("Staff Report"), of September, 2022 includes the recommendation that "New Jersey should adopt a formal policy requirement for purchasing capacity from clean resources over capacity produced by fossil resources."[1]

The Report goes on to specify that this policy should consist of a required purchase obligation on state Load Serving Entities (LSEs) to purchase and retire enough Clean Capacity Credits (CCCs) to meet a specified percentage of the capacity requirement allocated to each LSE in the PJM capacity market. The "clean capacity" percentage requirement would apply to both RTO-wide capacity and any locational capacity requirement that must be located within a constrained LDA in New Jersey.[2]

Staff proposes to define a CCC as the representation of "one UCAP megawatt of capacity, *as certified by PJM, for a particular delivery year or season, and particular PJM capacity zone* that is produced by a resource that does not directly emit GHGs […]" (emphasis added).[3] These CCCs would be differentiated by their eligibility to meet any locational capacity requirements imposed by PJM, to facilitate LSE compliance with the proposed proportionate requirement for clean locational capacity discussed above. CCCs needed for compliance with the clean capacity obligation would be purchased by LSEs and by other voluntary buyers, including those from outside of New Jersey, from eligible producers, either bilaterally or through a future centrally operated market such as the FCEM or a version of the ICCM.[4] However, the Report also suggests that the clean capacity obligation be implemented through either an ICCM or an FCEM, and generally appears to contemplate and favor a centrally operated market for meeting the clean capacity obligation.[5]

The proposed features above would create the demand, supply and structure of the bilateral or centrally operated market Staff recommends. These three components also provide sufficient detail for a preliminary diagnostic policy analysis of the proposal. In what follows, we first look at the economic implications of the proposed CCC market, and then discuss some additional policy-relevant aspects of the proposal.

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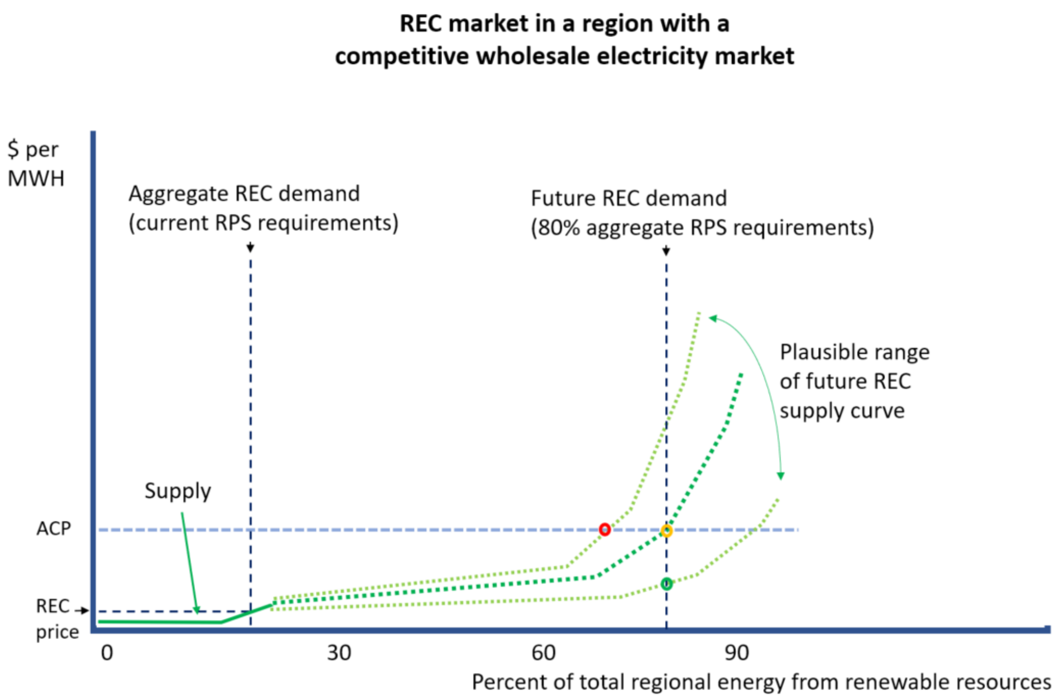
[1] Staff Report at p. 35.
[2] Id. at p. 40
[3] Id. I understand the italicized portion of this definition to require that CCCs can only be awarded to, or sold by, non-emitting resources whose capacity has cleared in PJM's Base Residual Auction for UCAP, which is generally held three years in advance of the delivery year for that capacity. Capacity resources that do not clear in the BRA are not assigned to a particular delivery year or season, do not have a capacity obligation in PJM, and are not able to provide capacity to PJM. This definition also means that any resources whose PJM UCAP is adjusted by PJM's version of the Effective Load Carrying Capability (ELCC) will only be able to sell the fraction of their nameplate capacity that is certified under the ELCC methodology, as discussed below.
[4] Id. at p. 42.
[5] Id. at p. 37. ("The purchase obligation in a Forward Clean Energy Market will also assist in creating both a promising participation level of both Clean Capacity Credits and clean energy attribute buyers […]").

2. Basic analytical framework and insights. Insights into the performance of a market for environmental attributes can generally be gained by carefully considering the basic elements of product definition, supply and demand. A graphical representation of these elements, reflecting power system dynamics as well as economic factors, is useful to gain general insights. For example, renewable energy credits (RECs) are a familiar, well-understood product, with one REC representing the environmental or renewable attributes of one megawatt-hour of renewable energy. The market for generic RECs from wind and solar resources, located in a large regional competitive wholesale power market such as PJM, can be graphically represented as shown in Figure 1.

FIGURE 1



The supply side of the REC market. Figure 1 represents the current and future supply function for RECs in a large regional market with low-cost wind and solar sites and the ability for such resources to recover their unavoidable or "going-forward" costs, and potentially at least a portion of their fixed costs, in energy, capacity and ancillary service markets. Competitive bids from such resources will reflect the zero out-of-pocket marginal costs of remaining in operation, plus the marginal costs of any risks or opportunity costs associated with selling, or committing to sell, a REC. However, if such resources become unable to recover their going forward costs through revenues from wholesale energy, capacity, ancillary service markets and from any state or federal incentive programs, their competitive bids into the REC market would also include the expected unrecovered portion of their going forward costs. For new resources to enter the market under such revenue conditions, the developers would need sufficient certainty regarding their potential to recover the unavoidable costs of developing and capitalizing a new resource, which could be provided by hedges or contracted REC sales at a sufficient price level.

The solid green supply curve assumes competitive bids from existing resources or broker-dealers who provide liquidity by buying RECs from resources and selling them to compliance entities. The dotted green lines project possible future marginal costs of providing the quantities of RECs demanded by higher RPS mandates. Note that all the illustrated REC supply curves show REC production increasing rapidly as REC prices increase, at least until renewable energy production provides sixty percent or more of total energy production. This large response of the quantity produced to increases in price means the supply of RECs currently is, and should continue to be, highly elastic, which is an economic term describing situations where the quantity of a good or service produced or consumed changes dramatically in response to higher or lower prices.[6]

As shown in Figure 1, the marginal costs of providing increased quantities of RECs could range from comparable to current levels to appreciably higher. This range of possible supply curves is indicated by the lighter green dotted lines, with the darker green dotted line representing a median path between the higher and lower curves. Several key factors will determine the actual supply curve for RECs, including the capital cost of new renewable resources, the capacity factor and cost of available sites, and the interconnection and transmission costs associated with delivering the power to the grid and ultimately to load. Some of these factors are likely to put upward pressure on the supply curve, others may provide countervailing downward pressure. Factors creating downward pressure on marginal costs include:

- Increased technical efficiency in wind and solar equipment, i.e., the ability to produce more electric energy from a resource of a given nameplate capacity at a given location.
- Lower capital costs for wind and solar plant components, due to continued innovation, competition and scale economies in manufacturing, shipping and installation.
- Increased demand for intermittent wind and solar energy production, which would reduce or eliminate curtailment and exposure to the zero or negative wholesale market energy prices that will otherwise increase in frequency and scope as deployment of wind and solar grow. For example, widespread use of wind and solar power to produce green hydrogen (a key component of several promising zero-carbon fuel technologies) during periods of otherwise excess production would counter the formation of negative or zero prices.[7]

Factors creating upward pressure on marginal costs include:

- Increasing capital costs for wind and solar resources, due to increasing demand for key materials and inputs needed to manufacture and deploy clean energy equipment.
- Increased siting and permitting costs associated due to dramatic increases in demand for land needed for high levels of wind and solar development, coupled with a fixed supply of land and increased competition for conflicting land uses.

[6] Elastic demand means consumption increases as price falls and decreases as price rises. Elastic supply means production increases as price rises and decreases as price falls. The opposite of “elastic” is “inelastic”, which means consumption and production do not change materially despite significant changes in price.

[7] A break-through in such clean fuels could potentially supply a highly cost-effective way to achieve full decarbonization of power, aviation, heavy transportation, and the production of cement and steel. In addition, it could provide an affordable approach to long-term storage of clean energy and thus maintain the essential reliability benefits of combustion turbine technologies, while eliminating the GHG emissions those technologies currently produce by combusting fossil-based methane gas.

- Increased transmission interconnection and deliverability costs, as growing amounts of wind and solar production require substantial additions to the transmission system in order to deliver the clean energy to load centers.
- Declining availability of sites with better quality wind and solar resources and a shift of wind and solar development to sites and regions with lower quality resources. This will drive down capacity factors (i.e., result in fewer MWH per nameplate MW of equipment) and thus increase the total project cost per MWH and per REC.
- Growing levels of curtailment of wind and solar resources when their production exceeds aggregate demand, further reducing capacity factors and spreading fixed costs over fewer MWH.
- Increased amounts of wind and solar will displace production by resources with higher marginal costs of generation in increasing numbers of hours, shifting the marginal price-setting resources in the energy market increasingly to resources whose marginal costs of production are lower than current price setters, zero, or even negative (due to the opportunity cost many resources will face of not receiving a REC, PPA payment, or output-based tax credit if they are not dispatched to operate). This trend towards lower and negative (i.e., pay to generate) wholesale market energy prices will drive down energy market revenues, leading to the need to recover more fixed costs in the capacity and REC market.
- Growing penetration of wind and solar will also lead to falling ELCC capacity ratings for these resources, reducing the amount of fixed costs they can recover in the capacity market, and thus pushing an even larger share of fixed cost recovery into the REC market.

The upward pressure factors appear likely to outweigh the downward pressure factors, but even so the future price path of wind and solar energy, along with the marginal cost of RECs, is substantially uncertain. The wide cone of uncertainty around future REC marginal costs in Figure 1 illustrates this uncertainty, and the potential for substantial movement in either direction, in the future supply of RECs. However, even a relatively pessimistic view of the cost of RECs in a future with high regional demand for them still entails a relatively elastic supply of wind and solar, and hence of RECs, with continued rapid deployment of renewable energy up to well over 50 percent of the regional supply of electricity.[8] as a cost-effective approach to achieve rapid early reductions in power sector GHG emissions.

The demand side of the REC market. The demand function for RECs is much simpler than their complex supply, and really has only two factors. One is the aggregate demand for RECs, based on the sum of state level RPS or similar mandates and any added demand in the voluntary REC market. The other is the existence and level of an Alternative Compliance Payment (ACP) in the various RPS mandates in the region. For clarity, Figure 1 shows a single ACP level across the regional REC requirements and assumes no RECs from this region are purchased in a voluntary REC market.

The demand function in Figure 1 is typical of demand in policy-driven programs with a single mandatory compliance level and a price cap such as an alternative compliance payment or other "safety valve" triggered by a set high price. Such demand functions are completely inelastic (vertical) when the price is below the ACP, and completely elastic (horizontal) when price reaches the ACP. Recall that

[8] Numerous well considered decarbonization pathways studies suggest that wind and solar can provide at least 50% of the region's electricity production without dramatically increasing costs. Figure 1 is drawn to be generally directionally consistent with the results of existing studies. See, e.g.,

completely inelastic demand means a higher or lower price makes no difference to anyone's decision to purchase, so below the ACP, higher prices will not reduce REC sales and lower prices will not increase them. Completely elastic demand means no one will buy a single additional REC if the price is any higher that the ACP, regardless of whether the mandate has been met.

Price formation in the REC market. The interaction of the supply curve for RECs and the demand function for them in Figure 1 determines the price of RECs. Specifically, since the supply curve shows the marginal cost of each REC, in ascending order, the price of RECs is equal to the marginal cost of the supply curve where it crosses the aggregate demand function, which is the marginal cost of the last REC needed to just meet aggregate demand. When the supply curve crosses the demand function below the ACP (for example, at the green dots on the current or future REC requirement levels in Figure 1), the full quantity of mandated RECs will be purchased by LSEs, and the REC market will clear at the price indicated by the supply curve at the point where it crosses the aggregate demand function. If, however, the supply curve crosses the aggregate demand function at the ACP level, the market will clear at a price equal to the ACP. If the supply curve crosses the aggregate demand function where the ACP and the mandated REC level intersect (e.g., the yellow dot in Figure 1), the mandate will be met and the REC market will clear at or just below the ACP level. However, if the supply curve crosses the aggregate demand function at the ACP level, before the mandate has been met (e.g., the red dot in Figure 1), the REC market will clear at the ACP level and no additional RECs will be purchased by LSEs, leaving the full mandated purchase unmet.

Relatively elastic supply, prior to high levels of renewable deployment, indicates REC prices are likely to remain reasonable while achieving aggressive increases in renewable deployment. The conceptual analysis embodied in Figure 1 indicates that a REC market could expand considerably in PJM, from its current levels, without reaching excessive costs, primarily because wind and solar technologies are already being deployed at low cost and at scale in the PJM market place. Accordingly, it is a relatively safe bet to assume that the future supply of RECs will not be excessively expensive or impossible to realize, at least until they reach some much larger share of the market than they currently provide. The conceptual analysis of Figure 1 cannot predict the threshold at which REC prices will rise dramatically, but it can show the potential directional risks associated with substantial growth in aggregate REC requirements, relative to current requirements. It suggests those risks and costs are both likely to be low until substantially higher levels of renewable energy deployment are reached.

A much more sophisticated analysis, with clear assumptions and appropriate sensitivity scenarios around those assumptions, is needed to even begin to predict or understand all the implications of an RPS requirement for very high shares of an entire region's electricity. Fortunately, there are ample such studies available to the BPU and interested parties, including those referenced at footnote __.

Two other observations are relevant to the analysis of the likely price and clean energy deployment impacts of a high RPS goal. First, the analysis depicted in Figure 1 considers the supply and aggregate demand for RECs within the entire footprint of a large, regional wholesale market such as PJM's. PJM reports that current RPS goals of states within PJM add up to about twenty two percent of total projected energy demand for all of PJM in 2035.[9] However, only about 4.2% of PJM's generation came

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[9] *Energy Transition in PJM: Frameworks for Analysis Addendum,* page 2. Available at https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211215-energy-transition-in-pjm-frameworks-for-analysis.ashx. Accessed October 23, 2022.

from wind and solar in 2021.[10] Thus it is clear that, to meet the aggregate demand for RECs under existing RPS goals, substantial new wind and solar development in PJM will be required. This means that the most RECs used to meet either New Jersey's current 50% RPS target for 2030, or an even more aggressive CES requirement would be from new resources, provided they are required to be sourced from resources that settle their energy transactions in PJM's market.

3. Applying this basic framework to a CCC obligation and market. It is straightforward to apply the same analytical framework to a New Jersey specific market based on an increasing percentage compliance obligation for CCCs with an ACP to limit high prices.

The demand side of such a market would be comparable to that of a regional REC market, with two key exceptions. First, the analysis of Figure 1 addressed the aggregate demand and supply for RECs in an entire regional market such as that spanned by PJM. By contrast, the proposed clean capacity obligation (CCO) would include PJM's locational capacity requirement for constrained locational deliverability areas (LDAs) that include New Jersey or portions of it. The proposed CCO would thus require meeting PJM's locational requirement for any constrained New Jersey LDAs with clean capacity resources physically located within the constrained LDA.

Second, the proposed CCO would be unique to New Jersey, such that there would be no demand from other states for capacity from clean resources; all the demand in the market would comprise New Jersey's capacity obligation, and all of that except any New Jersey locational requirements could be met by any non-emitting capacity resource in PJM. The net effect of these two unique demand features is that (a) the supply of existing non-emitting capacity resources in PJM, primarily nuclear capacity, would vastly exceed the demand for it in New Jersey, while the demand for non-emitting capacity resources to meet the locational requirements of constrained LDAs in New Jersey would, in all likelihood, substantially exceed the supply of such resources.

The supply side of the proposed CCO market, however, would be significantly different from that of the REC market. As an initial matter, under the proposed CCC product definition, the amount of capacity actually provided by many non-emitting resources would be dictated by PJM's use of a variant of the Effective Load Carrying Capability (ELCC) approach to determining the actual contribution to meeting a given standard for the acceptable amount of voluntary load-shedding due to an inability to generate enough electricity to meet demand at any critical times.

The critical importance of marginal ELCC ratings in a rapidly decarbonizing electric system. In any system with aggressive deployment of currently available clean energy resources, accurate ratings of the actual capacity contribution to meeting load during critical periods, through an appropriate ELCC or related methodology, will be critical for avoiding widespread power failures at times when people rely on electricity the most. Such power systems face a growing correlation between the down-times of wind, solar and battery storage, on the one hand, and high levels of electricity use, on the other.

For example, in a power system with high amounts of electrified buildings and transportation, electric demand will be highest on cold winter nights, when there normally is no solar. A concurrent bomb cyclone or winter hurricane with a prolonged period of cloudy days will reduce the availability of other clean energy resources. Offshore wind production would fall due to turbine shut-down when winds

[10] 2021 State of the Market Report for PJM, page 55. Monitoring Analytics, LLC.

exceed turbine specifications; solar production would fall during subsequent cloudy and snowy days; battery technologies will be discharged within hours and, without additional firm stand-by or reserve capacity available, unable to recharge; and demand response will have been largely used up.

To avoid these problems in a power system that has substantial and growing amounts of clean energy resources, it is necessary to evaluate the ability of various mixes of technologies to be able to meet load during such periods of correlation between unavailable energy inputs and high levels of demand. The marginal ELCC approach is a preferred methodologies for making this evaluation, because it accurately assesses the marginal or incremental contribution of specific types of technologies, given the resulting overall resource mix, to the ability to meet load during various such correlated events.

Resources whose addition to the system make only a small contribution to this ability receive a low ELCC rating, which has two implications. First, they sell a smaller amount of capacity (i.e., UCAP), and get paid for only that smaller contribution to avoiding load shedding, rather than selling their full "nameplate" capacity, which they cannot produce or deliver during such correlated events. Second, with all resources receiving an accurate marginal ELCC rating, a system that procures the amount of capacity (UCAP) needed to meet the system's reliability standard for an acceptable level of load shedding, will really be able to achieve that standard.

By contrast, rating UCAP of all resources at either the full nameplate rating or at an inflated, "average" ELCC rating, will result in an inability to meet the load shedding standard, without also inflating the total required amount of UCAP. This will increase costs relative to achieving a similar level of GHG emission reductions and reliability by using a more accurate, marginal capacity rating. Even the average ELCC approach, however, will create dramatic reductions in the amount of UCAP that is provided by a "nameplate" megawatt of renewable capacity as the power system decarbonizes in the coming decade, though the actual reduction depends on the overall system resource mix and specific resource locations. However, the more accurate and economic marginal approach will result in even greater reductions in the rated capacity provided by an incremental megawatt of wind or solar resources, especially as renewable penetration in New Jersey and throughout PJM increases in the coming decade. PJM is likely to shift to a marginal ELCC methodology for all resource types in the future, as its overall reserve margin falls and it faces increasing reliability risks as a result.

PJM's initial analysis for its energy transition studies projected that, in moving from the current system to one with 50 percent of energy from renewables, ELCC capacity ratings per MW of nameplate capacity could decline by 60 percent from today's ratings for offshore wind, and by 74 percent from today's ratings for solar. [11] These effects would likely be amplified by high levels of electrification of heating and transportation. Further, PJM is under pressure to better safeguard reliability by modifying its current "average ELCC" methodology to a marginal ELCC methodology, and to limit capacity ratings to the actual capacity injection rights of each resource. Both of these more accurate modifications would result in

[11] This result should be anticipated in PJM, which has already adopted an initial ELCC methodology based on average ELCCs. See, e.g., *Energy Transition in PJM: Frameworks for Analysis*. December 15, 2021 at pages 7-8. Available at: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwjg2f26t_f6AhUjlYkEHQtSCcwQFnoECBIQAQ&url=https%3A%2F%2Fpjm.com%2F-%2Fmedia%2Fcommittees-groups%2Fcommittees%2Fmrc%2F2021%2F20211215%2F20211215-item-09-energy-transition-in-pjm-whitepaper.ashx&usg=AOvVaw086G58f_ksFHt0eUlUldo_. Accessed October 23, 2022.

even lower ELCC ratings for variable resources. [12] Because of all these factors, potentially dramatic reductions in the rated capacity per nameplate megawatt should be anticipated for non-firm, variable resources that cannot produce their full output on demand during extended periods of high electricity use and low availability of wind and solar energy.

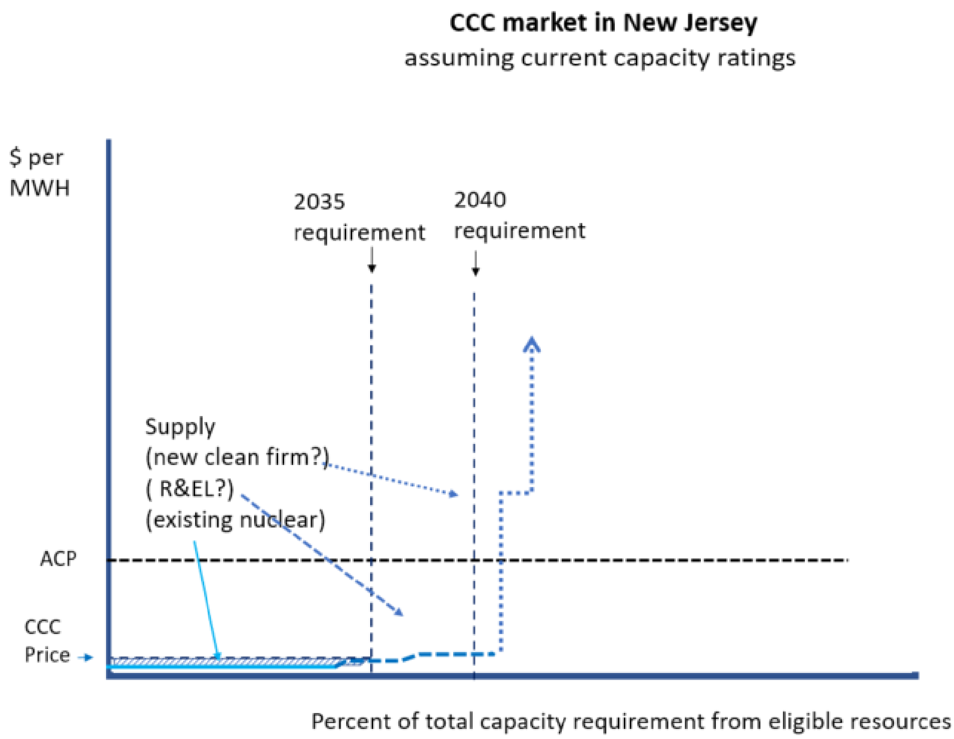
The quantity of CCCs supplied in a CCO market would shrink over time, along with their ELCC rating. Such dramatic reductions in the credited capacity of key existing clean resources would effectively shrink the supply curve, relative to its size under current UCAP rating methodologies used by PJM. The effects of such an "incredible shrinking supply function" are examined below. First, however, we discuss other aspects of the proposed supply of capacity credits.

The supply curve itself would consist of the marginal costs of offering a CCC for sale by existing eligible resources, which should effectively be zero for any resource that has already cleared the RPM market or that anticipates clearing the RPM market as a price taker, since any such resource will incur minimal incremental costs in offering its capacity, and will be recovering its avoidable costs and will therefore find a zero or price-taking competitive offer to be profit maximizing. It appears from the Staff Report that only clean projects that have cleared in the BRA, would be able to sell CCCs to meet the CCC obligation. Such projects, provided they have bid their avoidable costs -which, for developing projects, can be considerable -- into the PJM market and cleared, should also bid, under adequate competitive pressure, into the CCC market at very low bid levels.

Because the Staff Report does not mention or consider the impact of ELCC ratings, the analysis of the CCC market here begins with a scenario that assumes away the ELCC effect of shrinking the quantity of capacity provided by many clean technologies over time. This will allow us to better separate the effects of ELCC shrinkage of the supply curve from the more basic supply characteristics of the proposed CCC market. Figure 2, below, illustrates what a competitive CCC market would look like, assuming current capacity ratings for offshore wind, solar and battery storage resources. With fixed capacity ratings, these same quantities of resources would be expected to bid in future auctions, and to clear in those auctions, provided their bids do not exceed those of new entrants or the ACP.

[12] See, e.g., the *2021 State of the Market Report for PJM* by PJM's Independent Market Monitor, volume 1, at page 4. The market monitor concludes that "PJM's approach to calculating ELCC approach … is badly flawed" and should change to a marginal approach for all resource types, and reflect the capacity injection right limits of each resource.

FIGURE 2



In Figure 2, the supply curve consists of existing nuclear (solid blue portion of supply curve), existing or cleared new renewable and energy limited resources --i.e., qualifying storage and flexible load – (dashed blue portion of supply curve). All existing resources are assumed to bid as price takers, both because they have already cleared in the PJM capacity market and hence are presumably recovering avoidable costs, and because the marginal cost of selling a "clean capacity attribute" is zero. New resources meeting the LDA requirement may, however, face execution risk that justifies a slightly higher competitive bid. Finally, the conjectural future supply represents hypothetical bid levels from currently unavailable clean firm resources (dotted blue portion of supply curve). We assume the initial clean capacity obligation is set a level above that of existing nuclear and renewable units, since a mandate covering only those resources would not result in any new resources being developed, which appears to be a primary objective of the Staff proposal.

Under these assumptions, the initial CCC market clears at the slightly higher bids of renewable and energy-limited resources in congested LDAs, which creates additional revenues and margins, above and beyond their revenues from PJM's capacity and energy markets, for all resources that clear the CCC market. This result is clearly of dubious value to consumers and to clean resource deployment. Because CCCs can only come from a resource that has already cleared in the PJM capacity market, the only capacity attributes sold in the CCC market are non-additional or "anyway" credits, in that they come from resources that are already in operation or committed to development. Further, clearing in the RPM, where competitive bids are at the level of avoidable costs, implies all these resources have already met any financial hurdles for either continued operation or development in the PJM energy, ancillary services and RPM markets. As such, any such CCC revenues would be a pure, and gratuitous, transfer of income from New Jersey consumers to the resource owners.

It is clear from the Staff Report that staff views the ICCM as potentially pushing other fossil emitting resources out of the clearing portion of the BRA supply curve, and the Report tends to view the CCO as somehow equivalent to the ICCM. So perhaps the Staff Report recommendation is based on a belief that a clean capacity obligation in New Jersey would have the same effect. However, the ICCM would clear capacity bids from clean resources in the BRA, net of their clean energy attribute revenues in the FCEM, potentially resulting in a slightly lower *capacity* bids from capacity resources that are also able to sell clean *energy* attributes. The entry of more such bidders at the bottom of the BRA bid curve could potentially help push existing resources with higher avoidable costs out of the market.

By contrast, the CCC market would clear *capacity "*attribute*"* bids that must be made, after the resources have already cleared an equivalent amount of *capacity* in the BRA. There are no additional costs of providing the capacity "attribute," above and beyond all the net avoidable costs bid into, and recovered from, the PJM capacity market, so resources bidding into the CCC market at competitive levels will bid as price takers. Further, uncertainty regarding whether these resources will clear in Figure 2's CCC market, together with the very low expected competitive clearing price in the CCC market (absent the abuse of market power), seem likely to inhibit them from lowering their prior BRA bids.

Market power is not depicted in Figure 2's assumption of competitive bids, but it is a serious risk in a capacity attribute market in a constrained LDA, just as it is in PJM's market for real capacity. Market power, however, would not increase the supply or development of non-emitting capacity resources, it would simply extract a higher – potentially much higher – payment from consumers for existing or already committed new capacity. Thus, CCC market at existing capacity ratings, with or without the exercise of market power, appears likely to fail to accelerate clean resource deployment in New Jersey, and would simply transfer money from consumers to the owners of eligible resources that have already cleared the capacity market.

4. Analysis of a CCC market with ELCC - based capacity ratings that decline over time. The conclusions of the analysis of the CCC market in Figure 2 were that it would create no benefits at moderately low costs, under the assumption of a competitive supply, and at much higher costs with unabated market power in the CCC market itself. Figure 3, below, modifies the analysis to consider the much more relevant real-world case where the capacity ratings of key renewable and energy limited technologies decline dramatically as New Jersey and the PJM region rapidly deploy them. It also assumes substantial growth in the deployment, relative to today's levels, of offshore wind, solar and key energy-limited resources, and substantial declines in their ELCC-based capacity ratings.

FIGURE 3

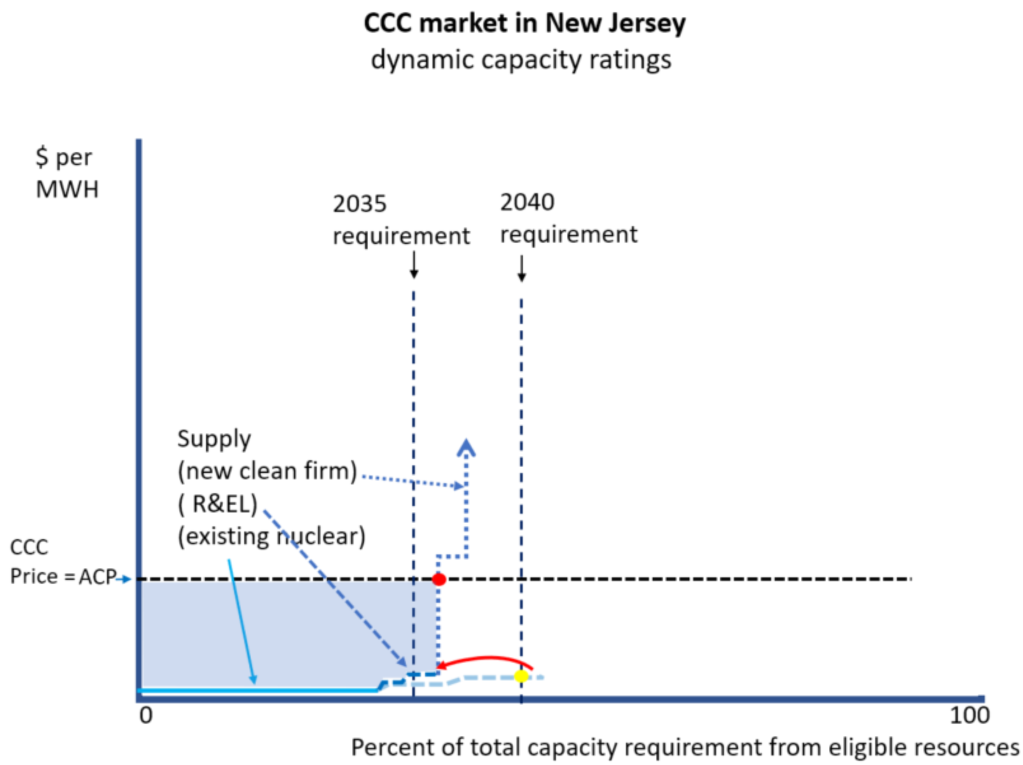


Figure 3 shows the CCC market in 2037, several years after its assumed start date.[13] The red arrow illustrates this decline in the ELCC-based capacity value of existing and committed offshore wind, solar and key energy-limited resources, due to their rapid deployment relative to today's levels. The decline in the quantity of this capacity shifts the price-clearing path between 2035 and 2040 from the prior light blue dashed line to the much shorter dark blue dashed line. Figure 3 includes the assumption that there is not enough eligible capacity available in New Jersey's constrained LDAs in 2037 to provide CCCs above the amount represented by the end of the dark blue dashed line. As a result, the supply curve becomes vertical (completely inelastic) at that point until it reaches the ACP, as designated by the red dot. In 2040, the CCC market then clears at the ACP, while procuring less than the mandated amount of CCCs, and scarcely more than at the program's initiation in 2035.

The result is disastrous from both a consumer and a clean energy perspective. Because the ACP is higher than the competitive bid levels of existing resources, total consumer payments increase dramatically (shaded blue area under and to the left of the ACP. These higher payments still fund only windfalls to existing resources, but at a much higher level. At the same time, the quantity of capacity procured from non-emitting existing or committed resources eligible to serve New Jersey's LDAs fails to increase, and may even decline from earlier cleared levels. Lowering the ACP would reduce the egregious windfall, but would still not attract the needed clean firm resources – even if, as depicted in

[13] Figure 3 assumes a regular annual increase in the mandated percentage of CCCs that must be purchased by LSEs, but to avoid clutter, does not show the nine annual mandate levels in between 2030 and 2040. The unshown demand curve for 2037, however, goes vertically up from the horizontal axis to the red dot in the figure.

Figure 3, the costs of one or several such technologies fall dramatically and they are on the threshold of commercial viability.

It is worth underscoring the key market design elements that lead to the problems in Figures 2 and 3.

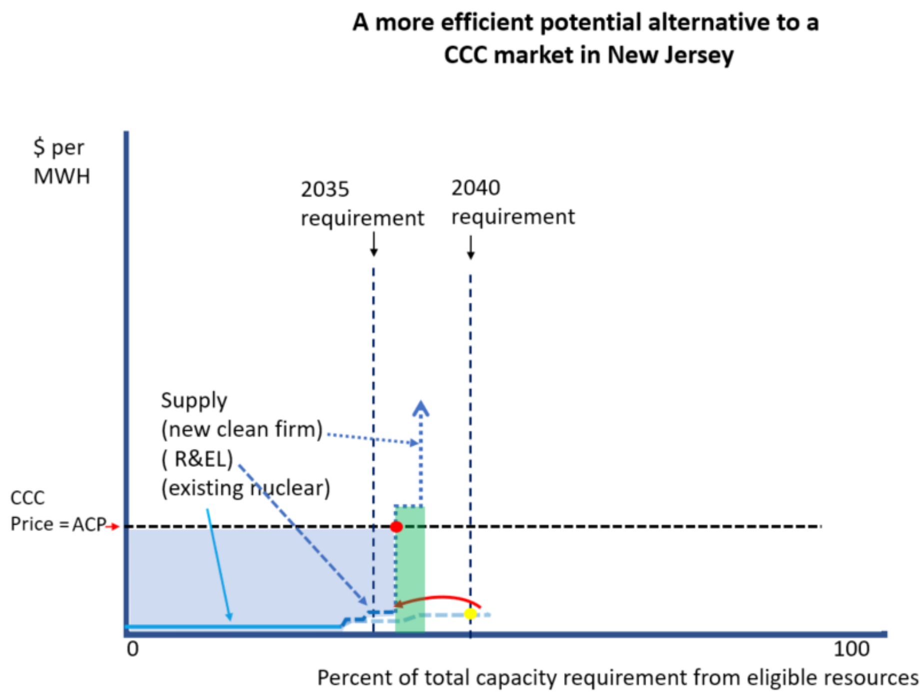
1. Both market scenarios lead to procuring CCCs from resources that already exist or are committed to complete development and begin operation.
2. If only existing or committed new resources can submit CCC bids, then the CCC market is unlikely attract or incent new entry, unless it allows new entrants to exercise market power.
3. Any prices above the competitive level would provide windfalls to existing resources, and any new resources that clear the BRA market.
4. Even if new resources, that have not cleared the BRA, could bid and recover their avoidable costs in the CCC market, the supply of CCCs is unavoidably inelastic, for three reasons.
    - Constrained LDAs are very difficult and expensive places to develop clean resources with high future ELCC capacity ratings.
    - Existing and new offshore wind and solar, along with commercially viable energy limited resources like battery storage and DR, face rapidly declining capacity ratings and provide comparably declining capacity benefits, as their penetration in the PJM region increases.
    - New clean firm technologies, that would not emit but have high and stable capacity ratings, and provide significant reliability benefits are not currently commercially viable and will likely have costs far above any reasonable ACP level well into the 2030s or 2040s.
5. Market power is likely to be an even more serious problem in a CCC market, in light of the locational capacity requirements in constrained LDAs in the Mid-Atlantic region, than it already is in PJM's capacity market.
6. Even without market power concerns, the combination of (a) mandatory purchases of a large and growing amount of CCCs, above and beyond current capacity requirements, and (b) a predictably inelastic (and potentially contracting) supply of those credits, is a surefire and proven recipe for persistently high consumer costs with little or no deployment of new resources. Such design failures can be difficult to correct, once established, since they earn very strong support from the relatively few parties that receive extremely concentrated benefits, and are often unrecognized by the many consumers who bear the much more diffuse costs.[14]

The BPU and Staff are already intimately familiar with the combination of a regulatory mandate with strong political support from its beneficiaries, plus a completely inelastic supply. Those are the key design elements that underlie the persistently high prices in New Jersey's SREC market. It is much

[14] There are numerous, additional design problems in the proposed CCC market. Key problems include: (i) batteries and demand response are unlikely to be truly non-emitting, unless they neither store nor shift consumption to periods of fossil energy production; (ii) the entire concept of "clean capacity" and "clean capacity attributes" are self-contradictory, since capacity is a measure of instantaneous energy output, which does not have emissions regardless of the technology, while all GHGs are emitted by producing MWH of energy, not MW of capacity; and (iii) a number of foreseeable jurisdictional challenges, based on both the *Hughes* case and on the observation that the only "attribute" capacity has is its contribution to resource adequacy (RA). For PJM participants, outside of the FRR alternative, transactions in RA are subject to FERC jurisdiction and the PJM tariff. All of these problems augment the risks and dilute any potential benefits associated with the CCO concept.

better policy, and much easier, to avoid creating such a persistently inefficient market, than it is to start one and then try to unwind it.

FIGURE 4



5. A potentially less costly and more beneficial approach to achieve the core goals of the CCO. Figure 4, above, helps illustrate an alternative to the CCO and market that would avoid the inherent mandatory demand and inelastic supply such a market is likely to entail.

The green rectangle in Figure 4 shows the total cost of achieving the deployment of an assumed new, clean-firm technology that is approaching commercialization in the mid-2030s. Two features stand out. First, the green rectangle is much smaller than the blue rectangle that would result from paying the ACP to existing and committed non-emitting capacity resources for their ACP. This means the clean firm technology's deployment would cost consumers considerably less than the CCC market would. Second, unlike existing and committed UCAP resources, the clean firm technology would not be deployed anyway through the incentives of PJM's wholesale markets. It may not even initially provide UCAP or participate in those markets. But it would be a fully additional resource, and incentive payments to it could be structured to help ensure its development and accelerate its broader commercial deployment. Both lower costs and substantial, real benefits make such a targeted incentive approach much more likely to be in the interest of both consumers and deep electric sector decarbonization.