CAPACITY WATCH

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EXECUTIVE SUMMARY

Third Quarter 2019

After a struggling start, offshore wind is poised for substantial growth in the Northeast power markets. Although challenges remain, state mandates are driving project development, with almost 5 GW in contracts awarded to date and more to come. Our front piece provides an update on offshore wind development in the Northeast, a discussion of how differences in capacity market rules may affect how offshore wind is integrated into the resource mix, and its potential impact on the Northeast capacity markets.

The strip auction for the New York 2019/20 Winter Capability period will open on September 27 and this issue provides our updated forecast for the upcoming winter. Also, ESAI's near-term and longer-term outlook has been updated to reflect a proposed change in the tariff rate for firm point-to-point service transmission service in PJM that exporters are charged in order to deliver capacity to the NYISO board to export. ESAI's assumptions regarding expected offshore wind additions has also been updated to reflect recent RFP awards.

In PJM, a late July FERC order suspended the 202/23 BRA that was scheduled for August. The surprise order has created additional uncertainty for prices in the next auction and perpetuated the longer-term uncertainty over the treatment of subsidized resources and rule changes for mitigation to protect against price depression.

In New England, ISO-NE just posted a preliminary value for the FCA14 ICR, reflecting a precipitous 1,260 MW drop from the FCA13 value. This reduction in demand for the auctions exacerbates the substantial oversupply in the market and dampens near- and long-term price expectations, despite the expected retirement of Mystic 8 and 9 by June 2024.

In This Issue

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OFFSHORE WIND UPDATE

SUMMARY

The promise of harvesting a proverbial "Saudi Arabia" of offshore wind resources in the Northeast has been elusive. While two early offshore wind projects won purchased power agreements (PPAs) that seemed to assure development, both failed to reach construction. Cape Wind filed its first interconnection request in 2001 and eventually won PPAs with the Massachusetts utilities in 2010 and 2012. But, in 2015, legal challenges lead Cape Wind to miss critical contractual milestones and the project was ultimately abandoned. Another early project – Bluewater Wind – signed an agreement with Delmarva Power for 200 MW in June 2008 but ran into financial difficulties in the 2009 recession. NRG bought the project in 2009 but shelved it in 2011. In New Jersey, the Fishermen's Energy offshore wind project had been under development since 2009 until Governor Christie blocked legislation that would have allowed New Jersey regulators to approve the project.

Despite this frustratingly slow start, offshore wind is gaining substantial momentum in the Northeast. Presently, the 30 MW Block Island Wind Farm in Rhode Island is the only operating offshore wind facility in the U.S., but a string of recent state-sponsored procurements is poised to facilitate the next level of development in the current infant U.S. offshore wind industry.

Demand for offshore wind generation is driven by state policy mandates and state-sponsored requests for proposals (RFPs). As described below, state-mandated solicitations have yielded almost 5,000 MW of contract awards in the past few years. But, the Cape Wind and Bluewater Wind projects demonstrate that attaining a PPA is not enough to ensure project completion. In the current class of RFP winners, Vineyard Wind was awarded a contract with Massachusetts utilities but has run into permitting issues that might delay the project, jeopardizing its qualification for federal tax credits. While the lineup of awarded Northeast offshore wind projects is impressive, some are likely to face difficulties getting to construction and many will face delays relative to original target dates.

Offshore wind's impact on capacity markets will depend on the specific power pool and project locations within the pool. The additional supply from large offshore wind projects is a bearish factor for capacity markets, but lower amounts of qualified capacity (30-45 percent of nameplate ratings) and the potential for offer price mitigation dampen impacts on the New York and New England capacity markets. The much larger size of PJM's capacity market dampens the capacity market impacts from offshore wind for the RTO overall, but still poses risks for import-constrained Locational Deliverability Areas (LDAs) where many of the projects off the east coast will be interconnected.

The following sections provide an overview of offshore wind development in the Northeast including a discussion of the drivers for development, regional offshore wind targets by state, awarded projects by state and implications for capacity markets in each of the three Northeast power pools. Several key take-aways are highlighted below:

- Obtaining a PPA is a major step in a long process towards project completion but is not a guarantee of success. Cape Wind and Bluewater Wind are examples of projects with PPAs that failed to move to construction.

- Expected capacity market qualifying capacity factors for offshore wind are higher than earlier expectations.
  - Vineyard Wind qualified capacity in New England at a much higher percentage than Cape Wind had as a result of technological improvements and a better wind resource by being further from shore (10-12 miles vs. 3 miles for Cape Wind)
- Two offshore wind projects were awarded contracts in the recent New York RFP. The 816 MW Empire Wind project will interconnect at Gowanus (Zone J), creating additional supply in the ICAP market, but the price impact will be at least partially offset by expected increases in the Locational Capacity Requirement (LCR) and retirements of aging peaking units expected in response to proposed new limitations on NOx emissions. The 880 MW Sunrise Wind project will interconnect in Brookhaven, Long Island.
  - Under current rules, the Equinor Empire Wind project would be subject to buyer-side mitigation but NYISO has filed a proposal at FERC that would exempt renewable resources.

- PJM has proposed a Minimum Offer Price floor for offshore wind resources of just over $30/kW-month as part of the package of mitigation reforms currently pending at FERC, though offshore would may qualify to be carved out from the capacity market. Current rules include a MOPR floor of zero for renewables.

- Offshore wind is interesting in the context of capacity markets not only for its potential price impact but also as an example of how capacity additions to support policy goals will impact the resource mix and market outcomes under various market rule constructs. Each of the three northeast capacity markets has a different approach to buyer-side offer mitigation designed to protect markets from the impacts of non-market supply. Each of the markets is also trying to establish rules to accommodate public policy goals.

KEY DRIVERS

State policies are the main driver for the progress seen to date in offshore wind development. Not only is there a trend towards higher renewable portfolio standard (RPS) requirements, but states are going further and mandating procurement amounts for offshore wind generation, with selected projects awarded long-term PPAs.

State-sponsored solicitations and contract awards are necessary due to the high cost of offshore wind projects. The current levelized cost requirements for offshore wind projects vary from $80 to $120/MWh, well above market but still a substantial decline from the original Cape Wind award price of $207/MWh (later negotiated lower by the Massachusetts

Attorney General to $187/MWh). With levelized costs at $80/MWh or higher, offshore wind remains far too costly to be supported by 7x24 energy prices near $40/MWh (or lower) in most regions.

Another driver is the trend toward increasing RPS mandates. For example, New York just this month increased its RPS target from 50 percent by 2030 to 70 percent by 2035. Other states have enacted similar increases. Developing onshore wind resources in New England and New York has been difficult as a result of siting and permitting issues as well as transmission system constraints. On land, most wind resources are far from urban load centers and located in relatively weak sections of the grid, resulting in high deliverability costs that most developers are unable to shoulder unless the enabling transmission is recovered regionally (*e.g.*, the renewable-enabling transmission efforts in Texas and California). While the cost of offshore wind is high, it is becoming closer to the cost requirements of onshore wind plus the enabling transmission.

Sheer size is a major advantage for offshore wind. New York's recent solicitation resulted in the award of almost 1,700 MW split between two projects. It might take as much as 20 to 30 onshore wind projects to meet the same nameplate MW amounts. Offshore wind also tends to have a much higher capacity factor than onshore wind; thus, the installed capacity of onshore wind facilities (including towers and turbines) would need to significantly exceed that of offshore wind facilities to match offshore wind production. Furthermore, offshore wind projects tend to dwarf solar projects, where even utility-scale projects range from 10 to 100 MW and have capacity factors of less than 20 percent.

As New York and New England struggle to meet RPS targets with land-based resources, supporting offshore wind projects provides a viable, high-volume alternative – albeit at higher cost and higher risk of completion. For developers, building large-scale offshore wind projects with long-term contracts that provide known returns is extremely attractive, particularly for those companies with a track record of project completions in other regions.

REGIONAL TARGETS AND COMMITMENTS

Ten states within the footprint of the three Northeast power markets have coastlines from which to exploit offshore wind resources (from Maine to Virginia). Of these states, seven have offshore wind mandates as described in Table 1 below. Two other states, Rhode Island and Delaware, do not have specific offshore wind mandates but have nonetheless been pursuing the development of offshore wind projects to meet their renewable energy goals.

Table 1: Offshore Wind Targets by State

	Mandate	Date Goal Established
Connecticut	2,000 by 2030	Jun-19
Maine	PUC required to approve PPA for 12 MW Aqua Ventus demonstration project	Jun-19
Maryland	2.5 percent solar carve-out (391 MW in development) + Additional 1,200 MW by 2030	Apr-13 (2.5% offshore wind carve-out established); May-19 (1,200 MW goal established)
Massachusetts	Procure 1,600 MW by 2027; DOER recommends procurement of additional 1,600 MW by 2032	Aug-16 (first 1,600 MW); May-19 (second 1,600 MW)
New Jersey	3,500 MW by 2030	May-18
New York	9,000 MW by 2035	Jul-19
Virginia	2,000 MW by 2028	Oct-18

New York has the most aggressive goal for procurement of offshore wind capacity, having set a goal of 9 GW by 2035. On the other end of the scale is Maine which has required approval of a 12 MW demonstration project. As shown in Table 1, other states have mandates that range from 1,200 MW (Maryland) to 3,200 MW (Massachusetts).

To date, nearly 5 GW of offshore wind capacity has been awarded contracts and is now under active development, as shown in Table 2 below. In addition to the projects in active development listed below, there is one completed project (Rhode Island's 30 MW Block Island Wind Farm, online in December 2016) and previous projects that were awarded PPAs but were ultimately cancelled (the Cape Wind and Bluewater Wind projects in Massachusetts and Delaware).

Regional Cooperation and Planning Issues

Several states can access the large wind resource potential located in federal waters, providing an opportunity for a larger single project to be developed at lower costs (due to economies of scale) to deliver energy to more than one state. Past renewable energy solicitations in New England provide good examples of interstate cooperation. The Clean Energy RFP completed in 2016 by Massachusetts, Connecticut, and Rhode Island did not select any offshore wind projects but laid a groundwork for interstate collaboration. The recent Massachusetts offshore wind solicitation included participation by Rhode Island, resulting in two states awarding contracts to two projects located in federal waters: Massachusetts awarded 800 MW to Avangrid/Copenhagen Infrastructure partners' Vineyard Wind project and Rhode Island awarded 400 MW to Deepwater Wind's (now Ørsted) 400 MW Revolution Wind project.

compared to New York and New England also means that significantly larger amounts of new supply are needed to substantially affect clearing prices. That said, the 26 percent factor means that the 1,100 MW Ocean Wind and 390 MW of Maryland projects (Skipjack and MarWind) would provide almost 400 MW of new capacity into EMAAC should it be allowed to clear.

CONCLUSIONS

Development of offshore wind will continue as state mandates increase and per unit costs come down with technological and other advances. As infrastructure needed to support these large projects is built and developers gain valuable local experience, costs will come down further, making investments in offshore wind more attractive to states. Despite surpluses in several markets, the states will continue to procure offshore wind as part of their renewable and local economic development goals.

For the smaller capacity markets of New York and New England, offshore wind could be bearish for prices, but mitigation may dampen price impacts. As noted above, the New York City capacity market will require new capacity to replace retirements of peaking units forced by new NO_X emissions regulations. But whether Empire Wind or other projects interconnecting into Zone J will clear will depend on application of NYISO's buyer-side mitigation mechanism and whether FERC approves a renewable exemption.

In PJM, capacity from offshore wind will be a much smaller percentage of the pool and therefore the price effects will be less. However, depending on the interconnection points, offshore wind could have impacts on locational pricing. As in the other regions, application of a MOPR and offer floors to offshore wind will determine whether eastern PJM LDA clearing prices (*i.e*. EMAAC) will be affected.

NEW YORK

SUMMARY

ESAI's outlook for the NYISO capacity market has been updated to reflect several recent announcements of importance:

- PJM Transmission Owners have filed a request for a significant increase in the Firm Point-to-Point transmission rates needed to support capacity exports to New York. The increase from $1.574 to $4.031/kW-mo has been included in the current outlook.
- NYSERDA announced the winners of its first offshore wind RFP with Empire Wind to connect 816 MW into Zone J and Sunrise Wind connecting 880 MW into Zone K.
- A substantial increase in the New England Installed Capacity Requirement (ICR) will result in lower ISO-NE capacity prices and reduce the incentives for New York suppliers to export to New England. As a result, supply in the NYISO market will be higher, dampening the outlook for longer-term NYISO ROS prices.

IMPORTS FROM PJM FACE REDUCTION FROM FIRM PTP TARIFF CHANGE

In June, the PJM Transmission Owners filed for a substantial increase (2.5 times) to the Point-to-Point (PTP) transmission rates. Firm PTP rates to the PJM border would go from $18.888/kW-year ($1.574/kW-month) to $48.374/kW-year ($4.031/kW-month). This specific rate applies to firm deliveries to the PJM border, specifically to facilitate exports of capacity to neighboring regions, such as New York. The Non-Firm discounted rate would remain at $0.67/MWh. A FERC determination has been requested by Monday Aug 12. If the TO filing is approved by FERC, ESAI expects a January 1, 2020 implementation as the Firm PTP rate is an annual rate.

Although the tariff specifies that the PTP rate is based on an average of PJM Transmission Owner costs, the PTP Border rate has not been updated since PJM's expansion in 2004. Although the tariff includes language that would add "Transmission Enhancement Charges" (TECs) to the rate, it was not clear whether this amount had included costs for RTEP upgrades. So, the Transmission Owners want to clarify the tariff to ensure that Firm PTP costs include RTEP upgrades (customers with FTWRs would continue to be charged for upgrades that have already been included in their rates).

The Transmission Owners proposed that the new rate use the same cost-of-service formula rate used to determine the regional Network Integration Transmission service (NITS) revenue requirements, thus including all regional transmission facility costs regardless of whether actually used to provide PTP service. Because the new formula PTP rate would not be known until cost data are available, the TOs presented an illustrative Firm PTP Border rate using 2018 cost data: the $48/kW-year rate.

As expected, the Merchant Transmission Facilities and their counterparties - Linden VFT, HTP, Neptune, NYPA, and LIPA - have protested the filing and want FERC to reject it or set it for hearing. IPPNY also weighed in to support the PJM Transmission Owners and the proposed higher charge for Firm PTP that would be used for capacity exports to NY.

On August 8th, FERC issued a deficiency letter on this filing. The PJM Transmission Owners have 30 days to respond to the numerous requests for clarification. Once this response to the deficiency letter is filed (by September 9th), FERC will have 60 days to issue an order. Therefore, resolution of this issue is expected by November 9th or slightly sooner if the PJM TOs file their response before September 9th.

The higher Firm PTP rate used for PJM capacity exports to New York would significantly reduce these export flows to New York and will be supportive for Rest of State capacity prices. With a firm PTP rate of $4.03/kW-mo, PJM exporters are likely to participate in the New York capacity market only if prices are expected to be somewhat higher than the PTP rate and provide a margin over costs. As noted in the Rest of State outlook section below, ESAI assumes that this proposal is more likely to be approved than not and assumes PJM imports will enter the capacity auctions when prices exceed $4.25/kW-mo.

As a result of the reduction in imports, summer Rest of State capacity prices will be supported at close to $4.00/kW-mo in 2020 and beyond. The impact for winter prices over the next few years are less impacted by imports from PJM as prices (and imports) were already low in previous outlooks. Starting in the winter of 2023/24, slightly higher prices had attracted imports in our previous outlook, dampening price recovery. The reduction of imports starting in 2023/24 in this current outlook, due to the higher Firm PTP tariffs, will increase prices to the $4.00/kW-mo level through the winter of 2027/28, up from the previous average of about $2.50/kW-mo for this period.

G-J prices are also affected by the reductions in imports from PJM. This is a result of the G-J zone clearing at Rest of State prices when the market is oversupplied, particularly starting in 2024 when the G-J LCR sees a significant reduction due to the impact of the PPTN upgrades. As such, a recovery in ROS prices in 2024 and after translate into higher G-J prices also.

Finally, Zone J prices will be affected this coming winter as the Linden VFT will be affected by the Firm PTP rate increase. For Linden VFT to break even on capacity exports from PJM to NYC, prices in Zone J must be higher than the $4.03/kW-mo Firm PTP rate to cover the cost of transmission service and the need to purchase firm capacity in PJM (PSEG).

NYISO WINTER CAPABILITY PERIOD OUTLOOKS

New York City Winter Outlook

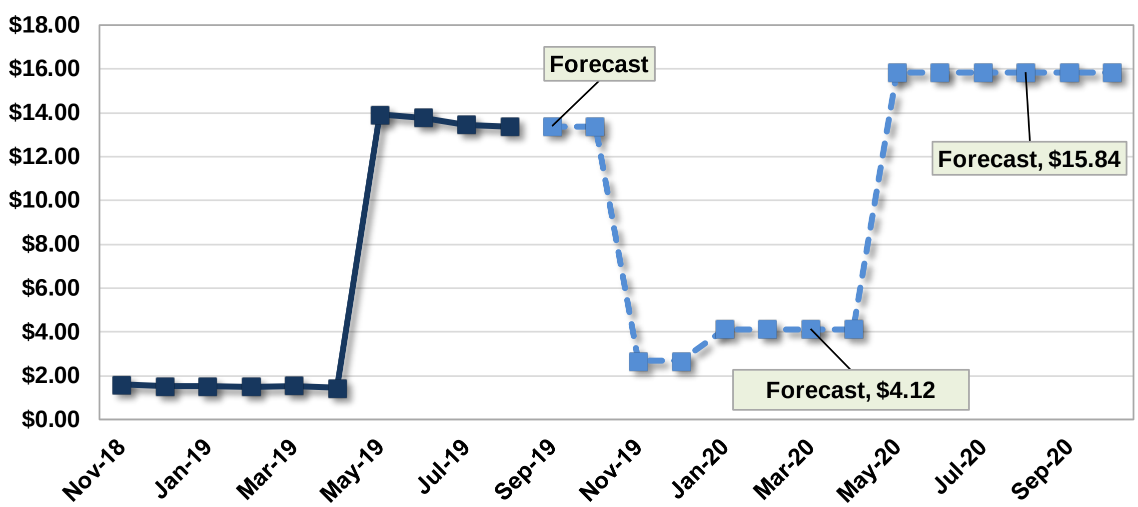
This summer, New York City capacity prices have risen from $10.00/kW-mo over the past two summers to just over $13.50/kW-mo, due largely to an increase in LCR from 80.5

percent to 82.8 percent. The driver for this LCR increase was the removal of the B/C feeder lines from New Jersey to Staten Island and the corresponding reductions in emergency supply that could come from PJM.

Last winter, NYC cleared with G-J at $1.52/kW-mo. This winter, that dynamic will change for two reasons. The first is that G-J will price lower at ROS levels ($0.18/kW-mo) due to the decrease in LCR from 94.5 to 92.3 percent relative to the previous winter as well as the addition of Cricket Valley capacity in February which will further pressure G-J prices this coming winter.

The second issue is that there is likely to be a change in the PJM Firm PTP transmission rate as discussed above. This will shift monthly NYC winter prices higher starting in January, assuming that the new tariff rate is approved and implemented for January 1, 2020. Prior to January, ESAI projects winter prices in November and December at $2.69/kW-mo. With the higher Firm PTP rate at $4.03/kW-mo, winter capacity prices will need to be at $4.03/kW-mo or higher starting in January, as the Linden VFT transfers capacity to the PJM border under this Firm PTP rate. ESAI projects a price of $4.12/kW-mo starting in January, but the ultimate clearing level will depend on the offer price submitted by the Linden VFT that could include the higher tariff rate as well as the cost of capacity purchased in PJM (PSEG). Note that if Linden VFT has committed to the Firm PTP service in advance, then this cost could be considered sunk and might lower the eventual bid level from VFT. However, if the full cost of the Firm PTP service plus the cost of capacity is included, then the bid price could be above $7.00/kW-mo (PSEG cleared the 2019/20 BRA at $3.64/kW-mo).

Figure 3: NYC Projections for Winter 2019/20 and Summer 2020 ($/kW-mo)



G-J Winter Outlook

As noted above, the drop in G-J LCR from 94.5 percent to 92.3 percent results in a surplus large enough for G-J to clear with ROS, projected at $0.18/kW-mo this winter. In addition, the Cricket Valley project is under construction and is still expected to enter operation in February 2020, well ahead of the summer. The retirement of Indian Point 2 in

PJM

SUMMARY

This issue of *Capacity Watch*™ discusses several important developments in the RPM capacity market that will affect the outcome of the next Base Residual Auction (BRA) for the 2022/23 Delivery Year, as well as the longer-term outlook. ESAI's Q2-2019 issue of *Capacity Watch*™ presented a detailed outlook for the 2022/23 BRA. However, July brought two important events that introduce substantial uncertainty for the auction. First, legislation passed in Ohio providing financial support to teo First Energy Solutions (FES) nuclear plants in the ATSI zone. The plants had not cleared in the BRA for 2021/22 and FES announced they would be retired unless financial support was approved. Because the current RPM rules do not include buyer-side offer mitigation for exiting resources, if the 2022/23 BRA had moved forward in August under the status quo rules (as planned), it is likely that the Ohio legislation would have resulted in the Ohio nukes being offered at zero in the BRA, depressing the RTO clearing price.

However, shortly after the Ohio legislation was passed, FERC issued an order suspending the auction until new market rules can be established in the on-going proceeding under FERC dockets EL18-178 and EL16-49. In that proceeding, the Commission deemed the existing RPM rules unjust and unreasonable because market clearing prices are depressed below competitive levels as a result of subsidies to otherwise uneconomic resources. The Commission is evaluating rule changes that include potential Resource Carve Out (RCO) options for state-sponsored resources and price mitigation to offset the effects of the resulting non-market supply. The auction is now postponed for a second time; it was originally scheduled for May 2019, then delayed to August, and currently suspended indefinitely, pending approval of tariff changes.

Although we do not know what rule changes FERC will approve, the delay introduces the potential that more favorable rules will be established in advance of the BRA and prevent price distortion from the Ohio subsidies, along with other resources with current or future state-sponsored financial support. However, the form that any final RCO and mitigation rules may take remains very uncertain. Additionally, the delay of the auction introduces the potential for other subsidies to be approved, for additional retirements to be announced, and for changes in the participation status of new generation projects under development and seeking financial close for debt and equity in advance of the BRA.

PJM also updated the Planning Parameters for the 2022/23 BRA in late July, with significant revisions to the COMED import limit and the reliability requirement for the RTO and several LDAs within MAAC. These parameter changes may affect the expected clearing prices and LDA price separation in the auction, especially for the COMED and MAAC LDAs.

ESAI has updated its forecast for the next BRA and the longer-term RPM outlook considering these recent developments. As discussed in detail below, the updated base case *price* forecast is changed only slightly from Q2-2019, but the projected *mix of cleared* *capacity* has changed, with subsidized resources now displacing other capacity. Moreover, the potential range of outcomes in the next BRA is now wider, given the uncertainty over the timing and substance of an order from FERC. Hence, we have provided discussion of additional potential scenarios and the impact on clearing prices. ESAI will continue to provide sensitivity cases that quantify the impacts of various market rules and state policy outcome in upcoming publications.

FERC SUSPENDS 2022/23 AUCTION

In a surprise order, on July 25 FERC denied PJM's motion seeking clarity regarding the 2022/23 base residual auction (BRA) that had been delayed to August 2019. FERC further directed PJM to not conduct the auction this month. In the brief order, FERC acknowledged "the importance of sending price signals sufficiently in advance of delivery to allow for resource investment decisions." Nevertheless, FERC concluded that "on balance, delaying the auction until the Commission establishes a replacement rate will provide greater certainty to the market than conducting the auction under the existing rules."

FERC had previously approved a delay in the auction, originally scheduled for May 2019, to August 2019 to allow development and implementation of new rules to replace the current tariff provisions, which the Commission deemed unjust and unreasonable in a June 2018 order rejecting proposed rule changes filed by PJM and accepting in part a complaint from suppliers under Docket EL16-49 that subsidized resources were leading to market prices below the competitive level. Planning to move forward with the BRA in August under the current tariff, PJM has requested that FERC confirm that it would accept the results of the BRA, despite being conducted under rules determined to be unjust and unreasonable. With this clarification, the results of the auction were very likely to be challenged and potentially overturned.

While the order was unanimous, three of the four Commissioners issued concurring opinions. Commissioners LaFleur and Glick, who dissented on the June 2018 order that found the PJM capacity market to be unjust and unreasonable, sharply noted how FERC's inaction in this proceeding has only worsened the uncertainty over PJM's capacity market.

Background

In June 2018 FERC rejected two proposals to reforming PJM's minimum offer price rule (MOPR) to address the influx of state-level subsidies to support otherwise uneconomic existing and new resources in the PJM market. FERC rejected PJM's proposal for a "Capacity Repricing Mechanism" that would have allowed subsidized resources into the capacity market as price takers but would have mitigated the price depression from this entry by resetting the auction clearing price using estimated competitive offers for subsidized resources (thus yielding a higher clearing price). FERC also rejected an alternative proposal from PJM's independent market monitor (IMM) that would have extended the MOPR floor to subsidized existing resources to protect against price suppression without guaranteeing that these subsidized resources would be counted as supply in meeting the Reliably Requirements under RPM (referred to a MOPR-Ex). FERC initiated a paper hearing to address an alternative it suggested based on an extension of the fixed resource requirement (FRR) provisions in the present rules (referred to as the "FRR-Alternative") and indicated that it would issue an order by January 4, 2019. In this paper hearing process, PJM developed two alternatives referred to as the Resource Carve-Out (RCO) approach and Extended RCO approach. Both options are designed to allow state-subsidized resources to opt out of the RPM capacity and instead be paid through state-sponsored procurement processes. The Extended RCO also includes a repricing mechanism designed to prevent subsidized resources that elect the Carve-Out option from artificially reducing auction clearing prices below competitive market levels. Stakeholders filed many comments in response to both the FERC order and its recommendation for the FRR-Alternative, as well as in response to PJM's two new proposals. Several stakeholders offered alternative market design ideas, including variations of the IMM's proposed MOPR-Ex and the CASPR mechanism that is currently in place in ISO-NE.

Following Chairman McIntyre's unfortunate passing last December, the four-member commission has been deadlocked on how to address the latest round of proposals to address the entry of state-subsidized resources into the RPM capacity market. FERC approved a delay in the 2022-23 BRA from May to August to provide more time to adjudicate these issues, but it became clear that with the four-member commission there would not be a majority to issue a decision.

In her concurrence to the July 25 order suspending the 2022-23 BRA, Commissioner LaFleur (who leaves office at the end of August) blasted the uncertainty created by FERC's inaction as "an act of regulatory malpractice." She underscored her opposition to the June 2018 order and further noted:

> *Now, more than a year after the Commission upended the PJM capacity market with no clear path to repairing it, we have still not acted to resolve the foreseeable and avoidable uncertainty created by our own actions.*

Commissioner Glick echoed these arguments, arguing that FERC "is now fully responsible for the damage done to date and whatever comes next." In his concurrence, Commissioner McNamee took issue with this statement, arguing that it ignores "nearly a decade of proceedings attempting to address the interaction between competitive markets and out-of-market subsidies."

Despite the rhetorical bout among the commissioners, the July 25 order unanimously and indefinitely suspends the 2022-23 BRA scheduled for next month, amplifying uncertainty over the future of the PJM RPM capacity market. The problem is that once FERC declared the existing capacity market unjust and unreasonable without establishing a just and reasonable replacement, the outcome of any future auctions under the now-unjust rules faced significant risk of being overturned in a court of law.

Potential Outcomes

While these concurrences filed with the recent order make clear the frustration over commission inaction, lack of a clear path to a solution, and the resulting uncertainty to the market, they do not provide any additional insight about what rules might ultimately be approved. With more than a half-dozen different proposals having been submitted by PJM, the IMM, and stakeholders, FERC is faced with the task of selecting among these proposals or developing an alternative. Finding a consensus is complicated by the seemingly incompatible objectives set forth by the Commission: accommodating state-sponsored resources to support public policy objectives while at the same time not distorting market outcomes from what would occur without the uneconomic supply from the subsidized resources. For example, if subsidized resources are to be accommodated as supply when they would otherwise be uneconomic, something else in the market must be displaced. And if prices signals are mitigated in order to better match what would occur in a competitive outcome, the supply decisions for many of the resources in the market will be disconnected from the actual price signals--resources will retire, despite price signals that suggest they should not shut down, and resources will enter or remain in the market despite price signals that do not support continued operation.

Which set of rules may ultimately emerge from the FERC proceeding is impossible to predict, but we can assess the extent to which each option proposed meets the objectives outlined by the Commission and stakeholders, and how well each proposals does or does not address the concerns raised in the order rejecting PJM's initial filing.

The simplest approach for the commission would be to accept one of the two proposals put forth by PJM. To the extent FERC is facing pressure to establish a working set of rules and restore some certainty to the market, this approach may provide the shortest path to a solution. However, each proposal has its drawbacks. (Note that these proposal are discussed in more detail in the last two issues of *Capacity Watch*™ and BRA scenarios under these rules are presented below.)

- ***RCO: Allow sponsored resources to be carved out from the RPM market, compensated for capacity (and other products or attributes) through non-market mechanisms, but apply no additional mitigation or repricing mechanism in setting the auction clearing prices.*** This proposal was crafted to be as close as possible to the resource-specific FRR option suggested in the Commissions June 2018 order. However, it would be the least effective at correcting the flaw that led the Commission to determine that the existing market rules are not just and reasonable. The RCO proposal would exacerbate rather than correct the price suppression that FERC determine was problematic, leading them to accept in part the Calpine complaint in EL16-49. Many parties have made this point in filed comments. If the Commissioners find this point compelling, straight RCO is unlikely to be approved.

- ***Extended RCO: RCO but with an additional repricing step that sets the price excluding the carved-out resources.*** This proposal may be the most effective at mitigating the price suppression from subsidized resources. It also would lead to the displacement of the highest-cost resources among those that would clear in the market, absent the accommodation of the subsidized resources. Hence, it

NEW ENGLAND

FCA14 PREVIEW – LARGE DROP IN ICR

The FCA14 qualification process for the 2023/24 auction is well underway, with FCA14 scheduled for February 3, 2020. Several auction details are now available, with a key auction parameter just released in early August: the preliminary value for the auction's installed capacity requirement (ICR) procurement amount. Other auction parameters, including locational requirement values and the demand curves, will not be available until late August (and on a preliminary basis).

ISO-NE is calculating two sets of ICR values: with and without Mystic 8 and 9. The two sets of values are needed because of the uncertainty over whether Exelon will accept ISO-NE's fuel security retention of the units for FCA14 or elect to unconditionally retire them.

The just-released preliminary FCA14 ICR with and without the Mystic units is more than 1,200 MW below the FCA13 value. If Mystic Units 8 and 9 remain service as retained for fuel security, the FCA14 ICR net of Hydro-Québec Interconnection Capability Credits (HQICCs) will be 32,490 MW, a 1,260 MW from the FCA13 Net ICR of 33,750 MW. Excluding Mystic 8 and 9 would increase the Net ICR very slightly to 32,495 MW.

Table 29: FCA14 vs. FCA13 ICR Analysis (Including Mystic 8 and 9)

	2023-2024		2022-2023		CHANGE	
	MW	Reserve Margin	MW	Reserve Margin	MW	Percent
Forecast Peak Demand (50/50)	28,839		29,093		(254)	(0.9%)
Assumed Existing Resources (incl. HQICCs)	36,147		33,867		2,280	6.3%
Installed Capacity Requirement (ICR)	33,431	15.9%	34,719	19.3%	(1,288)	(3.9%)
HQ Interconnection Capability Credits (HQICCs)	941		969		(28)	(3.0%)
NET ICR (to be purchased in FCA)	**32,490**	**12.7%**	**33,750**	**16.0%**	**(1,260)**	**(3.9%)**

ISO-NE explained that various improvements to weather variables in its 2019 CELT report load forecast resulted in a substantial decrease to ICR. The modeling changes reduced the gross summer peak load forecasts from 2018 by roughly 1.5 percent for the 50/50 forecast and 3 percent for the 90/10 forecast. The bulk of this decrease is attributable to the use of a new cooling degree day weather variable added to the model after benchmarking it against actual summer 2018 loads suggested that this new variable should be included.

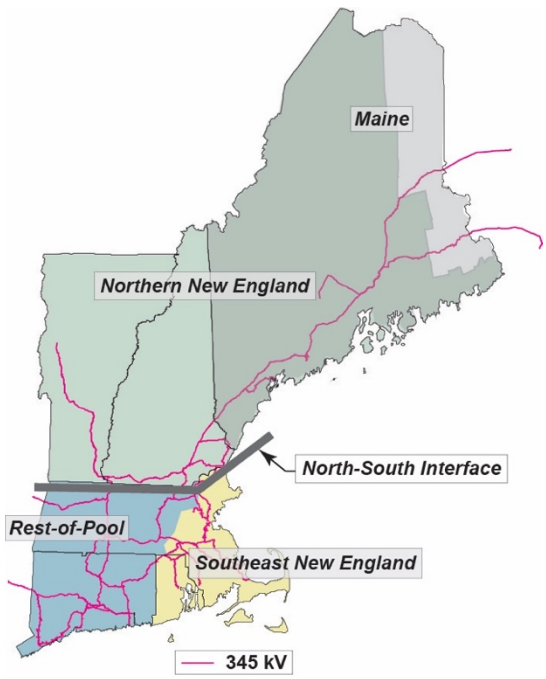
The GE MARS probabilistic model used to calculate the ICR uses an hourly load forecast reflecting a probability distribution, and the load forecast model changes push down the extreme load hourly forecast values (*e.g.* 90/10) by much more than the "middle" values (50/50). The roughly 3 percent drop in the higher load forecast values resulted in the probabilistic ICR calculation yielding a significantly lower value for FCA14. ISO-NE estimated that the addition of the second weather variable to the load forecast decreased ICR by roughly 850 MW. Had ISO-NE used the same load forecast methodology as in the 2018 CELT load forecast, the net ICR would have still decreased but only by 300 MW.

Our FCM outlook below incorporates the preliminary FCA14 ICR value.

Maine Export-Constrained Zone Nested Inside NNE

ISO-NE determined that the Maine-New Hampshire (ME-NH) interface (and state border) will be a capacity zone boundary for FCA14, with Maine as an export-constrained capacity zone nested inside the Northern New England (NNE) export-constrained zone (comprised of Maine, New Hampshire and Vermont).

Figure 22: FCA14 (2023/24) Capacity Zones



*The Maine zone is nested inside Northern New England.

ISO-NE will model an export-constrained zone in an FCA if the sum of existing qualified capacity and new capacity that could qualify in the zone (including imports into the zone) is greater than the zone's Maximum Capacity Limit (MCL). The total amount of capacity that could qualify in the zone excludes new resources expected to fail the capacity deliverability "overlapping impacts" test.

Under this process, the designation of Maine as an export-constrained zone is the result of ISO-NE qualifying a substantial amount of new capacity in Maine for FCA14. ISO-NE's capacity zone trigger analysis indicated a "headroom" of just under 200 MW of new capacity resources that could qualify in Maine before the new zone would be triggered. Details regarding new capacity qualified for the FCAs are not public, but ISO-NE confirmed that more than this amount of new resources has qualified in Maine, thus triggering the new zone. The most likely source of new Maine qualified capacity is imports from Québec over Avangrid's proposed New England Clean Energy Connect (NECEC), now with Massachusetts-approved purchased power contracts over the line. While some portion the backlog of renewable project interconnection queue requests in Maine could have qualified given ISO-NE's interconnection cluster study mechanism and potential enabling transmission upgrades, ISO-NE has separately confirmed that many of the cluster study wind projects in northern Maine have dropped out of the process. This outcome is not surprising given the steep cost of the enabling transmission upgrades.

Accordingly, FCA14 will have four zones: the Southeast New England (SENE) import-constrained zone, the NNE export-constrained zone, the Maine export-constrained zone nested inside NNE, and the Rest-of-Pool zone. As in past FCAs, the SENE zone will comprise of the NEMA/Boston, SEMA, and Rhode Island load zones, and the Rest-of-Pool zone will include only the West-Central MA and Connecticut load zones.

ISO-NE will determine a maximum capacity limit (MCL) and a separate marginal reliability impact (MRI) demand curve for the Maine zone. These values will be nested inside NNE, meaning that resources in Maine will count as NNE resources and supply. The descending clock auction clearing order will first clear the SENE import-constrained zone and then Rest of Pool, followed by NNE (if needed), then Maine (if needed), and then imports from New Brunswick (if needed).

CASPR Substitution Auction and RTR MOPR Exemption

FCA14 will be the second auction to conduct the Competitive Auctions for Sponsored Policy Resources (CASPR) mechanism, the secondary "substitution" auction designed to allow entry of state-sponsored policy resources into the capacity market that would otherwise be prevented from clearing because of their high costs and out-of-market revenue under the FCM's minimum offer price rule (MOPR). CASPR allows state-sponsored resources to replace retiring existing resources on a MW-for-MW basis. The CASPR substitution auction matches demand from retiring units with supply from new capacity offered by sponsored resources that did not clear the primary FCA. The retiring resource would be paid the net of the primary and secondary auction prices.

ISO-NE announced that 446 MW of existing resources elected to participate as demand in the CASPR substitution auction, with 279 MW submitting binding retirement and permanent de-list bids. Of this retirement and permanent de-lists bid amount, 148 MW are in Connecticut and 100 MW in Maine. Details are not available on the Connecticut amounts, but the 100 MW in Maine is almost certainly NextEra's oil-fired steam turbine Yarmouth Units 1 and 2. Both units cleared static de-list bids in FCA13 and FCA12.

ISO-NE received 2,972 MW of new sponsored policy resources seeking to qualify and offer as supply into the CASPR auction, including a surprisingly large amount in SENE (1,854 MW). We expect a portion of SENE sponsored resources to comprise of offshore wind resources; however, we expect only 40 to 45 percent of nameplate ratings to qualify as capacity. Roughly 1,500 MW nameplate of offshore wind has secured state-sponsored contracts to date (Vineyard Wind and Revolution Wind), representing a capacity value of about 600 MW. As a result, the balance of 1,200 MW of qualified sponsored resources likely comes from solar, wind and other types of state-sponsored resources.

Table 30: FCA14 CASPR Substitution Auction Demand and Supply

Capacity Zone	CASPR SA Demand Bids *	CASPR SA Supply Offers **
Southeast New England	103.56	1,854.26
Northern New England	0.12	138.53
Maine	100.00	254.68
Rest of Pool	242.78	724.94
TOTAL	**446.46**	**2,972.41**

* Excludes Mystic 8 & 9 (1,413 MW), which are on the retirement track but will be retained for fuel security for FCA14

** Amount seeking to participate as supply as of March 2019. ISO-NE's November 2019 FCA14 qualification FERC filing may provide an updated value.

We further note that only 100 MW of existing Maine resources intend to submit a demand bid into the CASPR auction. The CASPR rules substantially limit the ability for export-constrained capacity to replace retiring MW in import-constrained SENE. Assuming that most of the 254 MW of CASPR supply in Maine comprises of Hydro-Québec imports over the NECEC. We note that these imports do not qualify for the renewables MOPR exemption and are likely to be "MOPRed-out" from clearing in the primary FCA.

As part of the CASPR mechanism, ISO-NE agreed to retain the renewable technology resources (RTR) MOPR exemption but phase it out over a limited period, ending with FCA15 at the latest. For FCA14, the RTR MOPR exemption is capped at 336 MW. This cap decreases annually thereafter by subtracting the quantity of new RTR capacity cleared in the previous auction. For example, should 200 MW of RTR capacity clear under the exemption in FCA14, the FCA15 RTR MOPR exemption will be capped at 136 MW. If not exhausted in FCA14, the RTR MOPR exemption remains for only one more auction – FCA15 (2024/25). There are no changes to the eligibility rules for the RTR exemption; that is, the exemption remains limited to Class I REC-eligible renewables.

Demand Curve, Net CONE, ORTP, and Dynamic De-List Bid Threshold Values

FCA14 will be the first auction using the full MRI demand curve system-wide. The last three auctions (FCA11-FCA13) used a transition demand curve that was a hybrid of the FCA10 linear curve and the new, convex MRI curve. The transition curve followed the MRI convex demand curve for prices above the FCA10 clearing price of $7.03/kW-month, and then became linear and followed the same slope as the FCA10 curve. A comparison of the FCA13 transition and MRI curves is provided in Figure 17.

Table 35: Changes in Additions Since Last Update

Plant	Owner	Zone	MW (Nameplate)	Change	Cleared FCA (Y/N)
Medway Peaking	Exelon	SEMA	200	**Status:** Project enetred service in early June.	Y
Bridgeport Harbor CC	PSEG Power Connecticut	CT	576	**Status:** Project enetred service in June.	Y
Canal 3	Stonepeak Kestrel Holdings LLC	SEMA	330	**Status:** Project enetred service in June.	Y

Table 36: New England Retirements

Unit	Nameplate (MW)	Summer ICAP (MW)	Unit Type	Month	Year	Status	Location	Included in ESAI Base Case
Pilgrim	670	677	Nuclear	Jun	2019	Deactivated	SEMA	Yes
Front Street Diesels	8	8	Oil	Jun	2019	Slated	WMA	Yes
L Street Jet	19	16	Oil	Jun	2020	Slated	NEMA	Yes
Highgate Falls	3	3	Hydro	July	2021	Slated	VT	Yes
Attleboro Landfill	0	0	Landfill Gas	July	2021	Slated	SEMA	Yes
Bridgeport Harbor (Unit 3)	400	383	Coal	July	2021	Slated	CT	Yes
Pawtucket Power	69	60	Nat Gas	Jun	2022	Slated	RI	Yes
Mystic (Unit 7)	617	574	Oil	Jun	2022	Slated	NEMA	Yes
Mystic (GT1)	14	9	Oil	Jun	2022	Slated	NEMA	Yes
Mystic (Unit 8)	872	703	Nat Gas	Jun	2024	Slated	NEMA	Yes
Mystic (Unit 9)	872	714	Nat Gas	Jun	2024	Slated	NEMA	Yes
Economic Retirements ('24)	1,050	1,050			2024	At-Risk	ME / NH	Yes
Economic Retirements ('27)	1,250	1,250			2027	At-Risk	ME / CT / WMA	Yes
Total At-Risk	***2,300***	***2,300***						
Total Slated[1]	***2,874***	***2,471***						
Total	***5,174***	***4,771***						
Total in ESAI Base Case	***5,844***	***5,448***						

Note: For additional historical data, please reference ESAI PEP file.

Table 37: Changes in Retirements Since Last Update

Plant	Owner	Zone	MW (Nameplate)	Change
Pilgrim	Entergy	SEMA	670	**Status:** Deactivated (June 2019).

CALIFORNIA

INTRODUCTION

While dealing with the threat and impact of wildfires has become a major consideration in California's energy industry, other issues warrant more detailed consideration in this Capacity Watch. It also contains a summary of issues related to the PG&E bankruptcy, resource adequacy reforms/enhancements and the implications of potential massive amounts of energy storage under development.

PG&E BANKRUPTCY

Several items of note have occurred related to the PG&E bankruptcy.

- PG&E creditors filed a restructuring plan on June 25. The plan is based around a $30 billion investment by the group that includes $16 to $18 billion earmarked for 2017 and 2018 wildfire claims. The plan includes a proposal to change PG&E's name to "Golden State Power, Light and Gas Company," the name of a fictional Northern California utility company from Arthur Hailey's 1979 novel, Overload. PG&E opposes and Judge Montali is expected to reject the proposal.
- On June 7, bankruptcy Judge Dennis Montali denied FERC's claim that it has concurrent jurisdiction over the fate of PG&E's PPAs with power producers. The ruling would basically give him sole authority over PG&E's decisions to nullify the contracts. PG&E counterparties have filed appeals with the US Court of Appeals.
- On May 28, Montali ruled that PG&E customers will not be allowed their own committee in PG&E's bankruptcy, noting that customers do not have a claim for which separate representation by a committee is necessary." He rejected the claim that the annual GHG credit given to residential customers makes them creditors.
- PG&E requested that wildfire victims be required to submit proof of claim form by September 16. Parties are concerned that such a requirement may be difficult for some victims to provide.
- PG&E also announced that it has reached a $1 billion settlement with cities, counties, districts and public agencies in Northern California to resolve wildfire claims that had been filed.

WILDFIRE-RELATED ACTIVITIES

The California Legislature adopted AB 1054, would establish liquidity and insurance funds to deal with wildfire claims. Half of the $21 billion insurance fund would be provided by utility shareholders and the other half would come from ratepayers, through an existing Department of Water Resources bond charge that was scheduled to expire in 2022. The bill does not address the inverse condemnation principle that is responsible for much of the excessive utility liability.

Determined to beat this year's wildfire season, the CPUC approved wildfire mitigation plans for all of the respondents (PG&E, SCE, SDG&E, NextEra Transmission, Small/multi-jurisdictional utilities) as well as overall guidance.

A wildfire cost recovery financial "stress Test" was also adopted. It determines the maximum amount that can be extracted from utility shareholders without excessively impacting the financial status of the utility and its ability to continue serving ratepayers. The stress test does not apply to PG&E because it will be determined in the bankruptcy proceeding.

Powerline de-energization, known as the Public Safety Power Shutoff (PSPS) process, was adopted in hopes of avoiding future wildfires. The prospect of widespread extended power outages will further enhance the attractiveness of distributed resources and microgrids and has already resulted in a shortage of fossil-fueled emergency generators. Realization of the fact that a 7.5 kW propane-fueled emergency generator has a GHG emissions profile comparable to that of a coal power plant (~1kg CO_2e/kWh) will undoubtedly create much consternation in California's environmental community.

RESOURCE ADEQUACY ACTIVITIES

The CAISO and CPUC are both reevaluating the Resource Adequacy program in response to shifting resource patterns. Over 15,000 MW of solar PV generation have served to move the net load peak from mid-afternoon to evening, significantly reducing the value of solar MW for serving that load. The resulting morning and evening ramps have increased the need for flexible resources that can move up or down fairly rapidly. While many options are under consideration, development of a central capacity market mechanism operated by the CAISO, remains an anathema as California regulators remain concerned that FERC jurisdiction could interfere with California environmental concerns. The most significant activities are described below.

CAISO RESOURCE ADEQUACY ENHANCEMENTS

The CAISO has issued a revised proposal for Resource Adequacy Enhancements. Substantive changes from the previous proposal (summarized in the last Capacity Watch) include:

- The need to incorporate the UCAP component into the CPUC's Resource Adequacy program. The current proposal is to calculate UCAP = NQC * (1-EFOR), using weighted (50/30/20%) three-years of seasonal (summer = May through September) forced outage data to calculate EFOR.
- After additional analysis, concerns previously raised about potential speculative import RA resources not being available when needed does not appear to be a significant problem. As a result, the CAISO is no longer proposing real time bidding requirements for RA imports that have not received day ahead awards. It is also no longer proposing to change RA import must offer obligations to 24x7.

CAISO is also evaluating revisions to its generation deliverability assessment to better comport with the changing nature of grid needs. A straw proposal will be issued on July 29 in anticipation of an August 5 stakeholder meeting.

CPUC RESOURCE ADEQUACY ACTIVITIES

The CPUC has initiated its own assessment of RA import rules, requesting comment on the following issues:

1. Should Commission decisions
    a. require RA import contracts to include the actual delivery of firm energy with firm transmission and
    b. clarify that only a bidding obligation is deemed not sufficient to meet RA rules?
2. Do parties agree that firm transmission capacity is required in addition to firm energy? Please explain why or why not.
3. Should the Commission clarify its rules, or are existing decisions and requirements sufficient? If the former, please propose clarifying language and/or how such clarifications should be established.
4. If the Commission determines that RA import contracts with a bidding obligation, but without delivery of firm energy with firm transmission, do not qualify as RA, how should these types of contracts be addressed going forward? Should these contracts be disallowed for the balance of 2019, beginning in 2020, or at a later date?
5. How should LSEs document that their RA import resources meet the Commission's import rules? Examples may include, but are not limited to, LSEs providing attestations or certifications for each import contract or attestations from the import provider.
6. If necessary, how should Energy Division staff determine compliance?
7. If it is determined that the imports used by an LSE do not meet the Commission's firm energy requirements, does the existing RA penalty structure provide enough deterrence to prevent further transactions of this type? If not, what additional remedies or corrective measures should be imposed?

Local and flexible RA requirements for 2020 have also been adopted and are shown in the tables below. Note that the local capacity requirement includes an obligation to procure 100% of local obligations two years ahead. There has been very little progress in the development of a Central Procurement Entity for local RA.