CAPACITY WATCH

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2nd Quarter 2018

EXECUTIVE SUMMARY

In this issue of *Capacity Watch*™, ESAI Power discusses generator strategies for retirements. In particular, we review the recent trend of threatening the closure of generating assets to highlight the reliability or environmental attributes that would be lost if the units were to retire. While generation owners are expected to act in their own best interest to obtain additional revenue, ESAI Power discusses the risks to markets from providing out-of-market payments not available to all market participants.

In PJM, ESAI Power provides a detailed overview of expectations for the upcoming 2021/22 BRA. RTO and MAAC prices are expected to clear at $86.69/MW-day with EMAAC clearing at $150.69/MW-day and ComEd at $175/MW-day. For New England, we provide a detailed breakdown of the FCA12 results as well as a discussion of the potential for fuel-security reliability payments for the LNG-fueled Mystic 8 and 9 combined cycle units. In New York, NYISO has issued its final 2018 Gold Book load forecast, which has been incorporated into our outlook. We conclude with an update of capacity activity in California.

In This Issue

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Retirements and the Need for Market Reform

The future of wholesale power markets remains tenuous. The threat posed by state policy actions to deliberately circumvent or revise market outcomes is well documented, with the past 18 months seeing substantial activity on ways to reconcile and accommodate state policies and wholesale power markets. States are pursuing these actions because of a real or perceived view that wholesale power markets are not designed to achieve the states' desired policy outcomes. Competitive wholesale power markets aim to provide transparent price signals for the efficient and competitive operation of, and investment in, energy infrastructure. However, these markets typically do not account for the value of other products or attributes that the states are mandating, such as low-carbon electricity production, price stability, or renewable generation expansion.

As states enact larger mandates for renewable and low-carbon energy resources, the conflict between wholesale power markets and state public policies continues to worsen. Many states view renewable portfolio standards (RPS) and other policy mechanisms as insufficient to meet their policy and statutory mandates. This conclusion has led to mandated, out-of-market cost-support mechanisms and long-term contracts with desired clean energy resources. In response, wholesale power market participants complain that the states deliberately interfere with markets by enacting laws and other mandates designed to suppress wholesale market price outcomes. FERC and the RTOs share this concern. All three Northeast RTOs are studying market changes to address the wholesale market impacts of more state-sponsored resources. In March, FERC approved the first of these market changes to address state policy resources: ISO-NE's Competitive Auctions for Sponsored Policy Resources (CASPR) mechanism to accommodate state-sponsored resources into the ISO-NE capacity market.

But, it is not just states that seek to interfere with market outcomes. Market participants are also actively pursuing out-of-market compensation for their assets. In particular, retirements are increasingly being used as a tool to either sidestep markets or drive major market design changes. Many entities blame poor market design and argue that they are left with no other choice but to seek out-of-market compensation. While doing so might be consistent with these entities' fiduciary duty to their shareholders and investors, the actions ultimately undermine their own interests as well as those of all market participants. At a time when competitive markets are under attack, this new front is a troubling development.

Using Retirements to Shape Market Outcomes vs. Seeking Out-of-Market Cost Support

A core objective of RTO capacity markets is to provide price signals for the entry of new capacity resources, the retention of efficient existing resources, and the efficient exit of uneconomic capacity. Many factors influence capacity auction clearing prices, but supply reductions from resource retirements have been responsible for major price shifts in all three Northeast RTO capacity markets. In PJM, over 20 GW of coal-fired unit retirements helped support recovery from record low RTO clearing prices in the 2012/13 BRA, despite other bearish factors (including falling load forecasts). In NYISO, the mothballing of in-City resources helped Zone J (New York City) clearing prices recover from a significant downturn following the entry of new resources. The Indian Point retirements in 2021 and 2023 will also support higher Lower Hudson Valley clearing prices. In New England, capacity clearing prices swung from an administrative price floor in 2016/17 to just below the auction starting price as a result of 3,000 MW in retirements, including the 1,500 MW Brayton Point station.

Yet, significant concerns about retirements persist, with low prices not always triggering the retirements needed to thin out uneconomic capacity. Resource adequacy, reliability, and other concerns often trump the invisible hand of capacity markets, creating barriers to retirement of generation resources units even when it is economically rational to do so. Load advocates and regulators fret over the use of retirements as a "withholding" tool to increase prices and the value of an owner's remaining portfolio of resources.

A generation asset owner's decision to retire is seldom straightforward. It depends on a myriad of factors, not all of them financial. Many issues can play a major role in retirement decisions, including system reliability and resource adequacy needs, environmental emissions and water use requirements, and local political, employment, and tax base implications. At bottom, a competitive market should allow retirement decisions to be based on the economics of operating the unit going forward, and asset owners should not be blocked from retiring a money-losing resource. But, the question of whether a resource is economic is not straightforward and depends on not only expected costs and operating expenses, but also the risk tolerance and strategic plans of generation owners. With uncertain information, RTO rules regulating retirement decisions can risk preventing competitive resource owners from retiring assets because of differing views of going-forward costs and economic viability.

Rather than seek higher price outcomes, actual or threatened retirements are increasingly being used as a tool to change policy and market design. The Northeast RTO markets have seen several high-profile retirements used to advocate for substantial market changes.

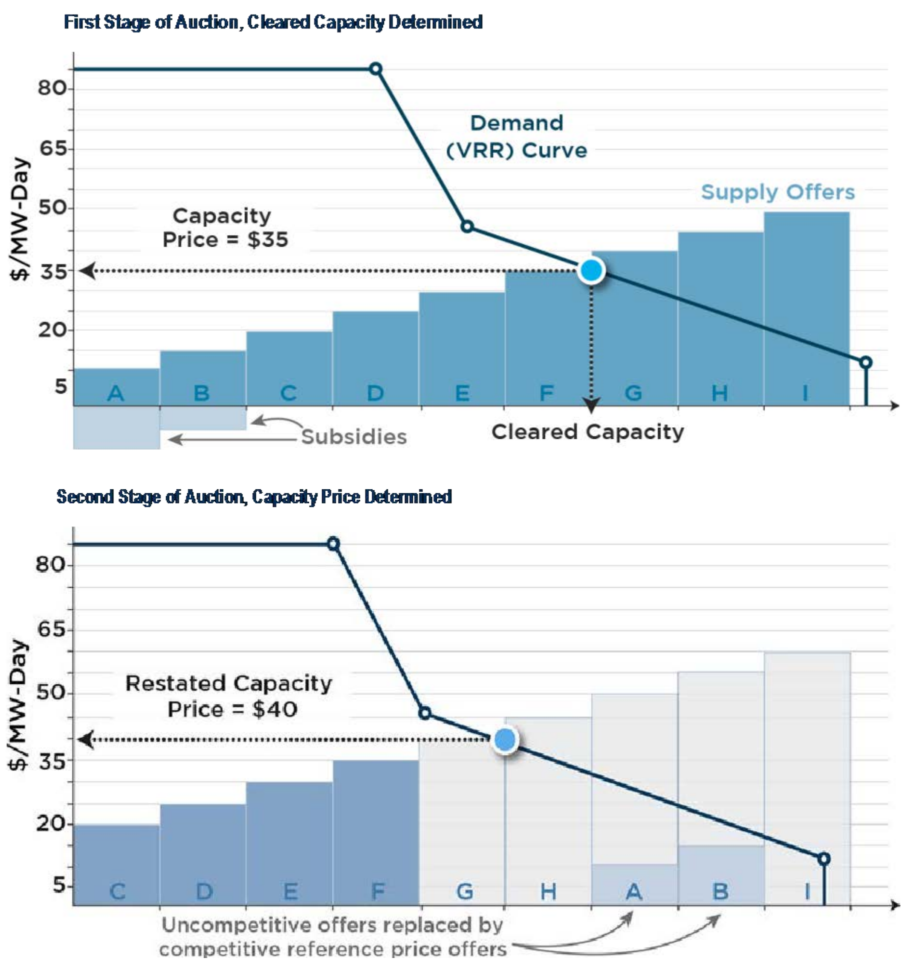
PJM: Baseload Retirements Drive Market Changes; Request for DOE Emergency Order

PJM has already seen dozens of GW in coal-fired and nuclear retirements, with reliability maintained and prices remaining generally low, partly because of the entry of new gas-fired resources. The retirements have also led to transmission improvements in various areas of the PJM system. Yet, concerns over additional retirements are driving PJM to consider significant energy and capacity market changes.

In the energy market, PJM is considering revising the calculation of LMPs to let inflexible units (coal-fired and nuclear units) set LMPs for a sustained period, despite more flexible units being on the margin. Instead of paying uplift to inflexible generating units and setting LMPs at flexible units' offers, PJM would set the LMP so that it reflects offers/opportunity costs of inflexible generating units. The proposal would include a new load-following compensation mechanism to pay flexible resources forced to ramp up or down uneconomically when inflexible resources must operate at a minimum output level.

As for the capacity market, on April 9 PJM filed at FERC two proposals for addressing the impact of subsidized resources (including existing units) on the RPM capacity market. PJM's preferred proposal is its 'Capacity Repricing' mechanism with a two-stage auction approach. The first stage of the auction would determine the total quantity cleared and to be paid as capacity – but not the price for that capacity. In the first stage, subsidized resources (new or existing, with subsidy status determined by PJM) would offer into the auction without being subject to mitigation under PJM's minimum offer price rule (MOPR). In the second stage, PJM would re-insert the subsidized resources at mitigated prices (per the MOPR) into the supply stack and clear that supply curve against the original demand curve. The price resulting in the second stage of the auction would be the price paid to all resources that cleared the first stage of the auction – including any subsidized resources that cleared the first stage. Note that resources that offered at a price below the second stage clearing price but that did not clear and receive a commitment from the first stage (the so-called "in-between" resources) would not receive a commitment and would not be paid through the auction.

Figure 1: PJM "Capacity Repricing" Two-Stage Auction Proposal



New York

NEGATIVE PEAK LOAD GROWTH FORECASTED FOR NYISO

The NYISO has posted its final 2018 Gold Book, which includes demand forecasts for NYISO overall and each zone within the state. As shown in the charts below, the peak load forecast has been revised down substantially compared to the 2017 Gold Book forecast.

For the overall NYCA statewide forecast, the 10-year growth has shifted from almost flat in the 2017 forecast to negative in the 2018 forecast. The NYCA Gold Book peak load growth rate is -0.4 percent for the period 2018-2023 and 0.1 percent for the period 2024-2028. The 2019 NYCA summer peak load has dropped by 178 MW in the 2018 Gold Book relative to the 2017 Gold Book. The 2026 NYCA summer peak load has dropped by 981 MW in the 2018 Gold Book relative to 2017, eliminating the slight load growth seen in the latter part of the 2017 forecast. The final 2018 Gold Book NYCA coincident peak load forecast is exactly in line with the preliminary outlook issued earlier.

Figure 2: NYISO Statewide Peak Load Forecast

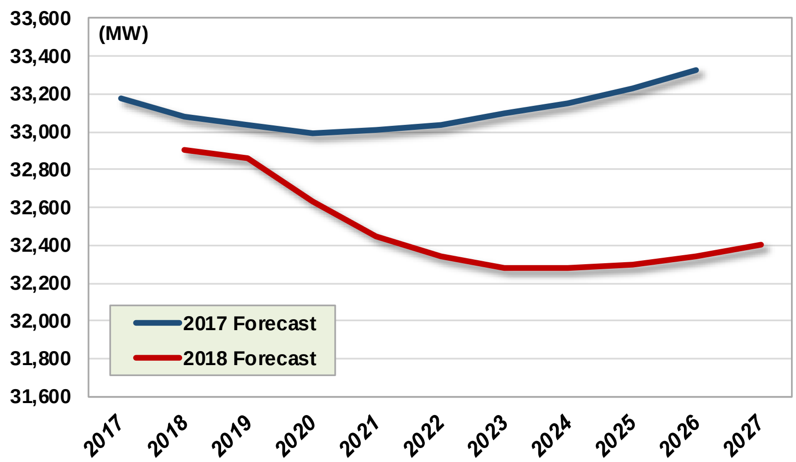
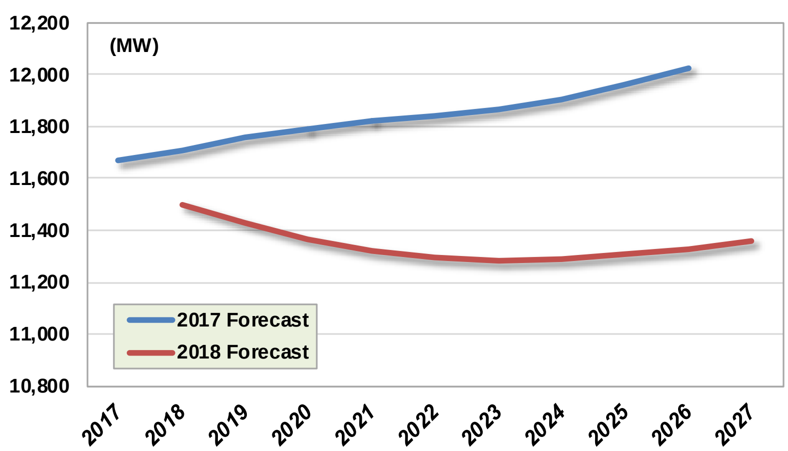
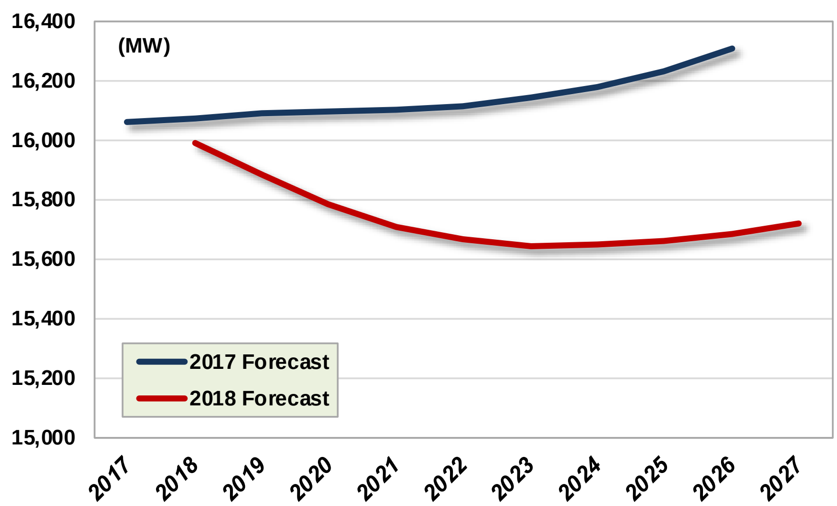


Figure 3: NYC Peak Load Forecast



For New York City, the 2017 forecast included positive growth of approximately 0.2 percent, while the 2018 forecast calls for the peak load to decline at an average rate of 0.14 percent over the next ten years. Similar to the NYCA forecast, the New York City outlook includes a decline through 2024, followed by slight positive growth over the last few years of the forecast.

Figure 4: G-J 2018 Gold Book Peak Load Forecast



The drop in the 2018 summer peak loads had already been incorporated into the ESAI New York forecasts, as the ICAP peak load forecasts were issued in mid-December (see the Q1 2018 issue of *Capacity Watch*™). With negative peak load growth, price increases in the market over time will need to be driven by retirements of uneconomic older capacity. As discussed below, economic retirements are expected for New York City and included in ESAI's base case.

NEW YORK 2018 SUMMER STRIP AUCTION RESULTS

On March 30, the NYISO posted the results of the six-month strip auction for the 2018 Summer Capability Season, which begins on May 1. The Rest-of-State (NYCA) clearing price was $1.75, in line with ESAI's forecast for the average spot price for the summer. The ROS price is expected to be lower than last summer due to the lower peak load forecast and continued imports from the PJM market. Additionally, both the Bayonne expansion (Zone J) and CPV Valley CCGT units are expected to be online as early as May 2018. Should these units be delayed beyond the May COD included in ESAI's base case, higher prices for NYCA (as well as Zone J and the G-J Locality) could result. Partially offsetting these capacity additions is the expected retirement of the Selkirk units in Zone F. The timing of the retirement is uncertain due to NYISO reliability analysis that is currently underway and must be completed before deactivation. The NYISO is targeting mid-May for completion. ESAI has assumed that the plant will not be in the market for May 2018. Should the retirement be delayed, prices could be lower, especially for the next few months.

The G-J Locality and Zone J clearing prices for the summer strip were slightly higher than ESAI's expectations, as reflected in the seasonal average forecasts shown below. The difference likely reflects expectations about the timing for the CPV Valley and Bayonne projects. If neither project is completed, EASI expects that spot prices could be above $13.00/kW-mo. However, with both units in, the summer spot is expected to be just below $9.00/kW-mo for G-J and just above $9.00/kW-mo for New York City.

NEW YORK ICAP MARKET PRICE FORECAST

ESAI's forecast for NYISO ICAP market clearing prices are shown below. The key assumptions and drivers of the forecast are:

- Peak load growth - Will be negative through 2023 for NYCA and in each of the capacity zones. After 2023, load growth will be flat to slightly positive.
- LCR – The base case assumes that the revised methodology for setting LCR will be implemented for the 2019/20 capacity year.
    -
    - The LCR optimization proposal passed in the management committee with a 77 percent approval, but has been appealed. A NYISO board decision is expected in early May and a filing to FERC is expected subsequent to the May board decision.
- Retirements – Announcements for retirements are picking up and providing an offset to lower load growth and new generator additions.
    - ROS – Selkirk is expected to retire in May 2018 pending its deactivation study.
    - LHV (Zones G-J) – Indian Point retires Unit 2 (980 MW) in April 2020 and Unit 2 (1,020 MW) in April 2021.
    - Zone J – In April 2018, 160 MW of peaking capacity was retired at Ravenswood.
        - Generic retirements include 50 MW 2019, 180 MW in 2020, 50 MW in 2022, and 420 MW in 2023.
        - The 2023 retirements are a result of pending NOx rules in Zone J that will pressure retirements similar to the HEDD NOx rules in NJ that resulted in significant retirements.
- New Generation – Two new generators are expected to commence operations in 2018:
    - The 650 MW CPV Valley plant is included as a May 2018 startup. Any delays would improve G-J prices above the base case forecast in those months.
    - The 116 MW Bayonne expansion is also included as a May 2018 startup. Similarly, any delay will be positive for Zone J prices in those months but the unit is expected to be operational by May.

Figure 9: Select ESAI Project Evaluation Program Projects

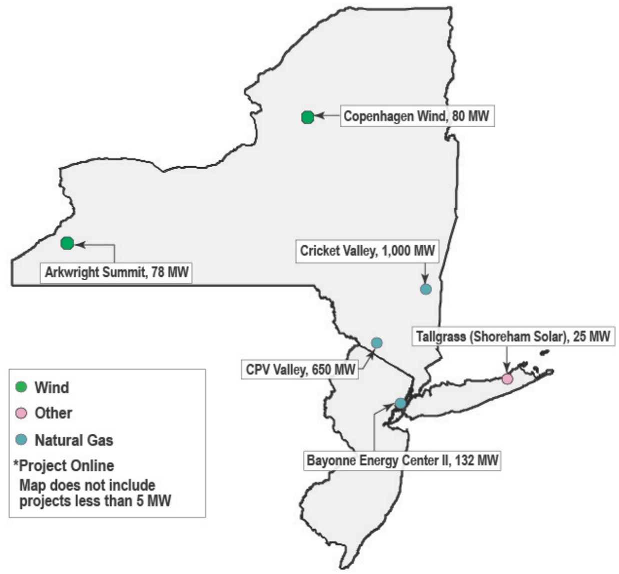


Table 6: New York Capacity Additions

Unit	Capacity, MW	Unit Type	Month	Year	Location	Included in ESAI Base
Orangeville Wind Farm (Stony Creek)	94	Wind	Jan	2014	ROS	Yes
Danskammer Repower (Units 1 and 2)	120	Nat gas	Sep	2014	ROS	Yes
Ravenswood 3-4 Restart	43	Kerosene	Oct	2014	NYC	Yes
Marsh Hill Wind	16	Wind	Dec	2014	ROS	Yes
Danskammer Repower (Units 3 and 4)	315	Nat gas	Dec	2014	ROS	Yes
Standard Binghamton Cogen	48	Nat gas	Dec	2014	ROS	Yes
Astoria Station Unit 20 (Return)	180	Nat gas	Dec	2014	NYC	Yes
Bowline Unit 2 (Return)	387	Nat gas	June	2015	ROS	Yes
Independence Uprate	45	Nat gas	June	2016	ROS	Yes
Jericho Rise Wind	80	Wind	Dec	2016	ROS	Yes
Greenidge Unit 4 Repower	107	Nat gas / Biomass	Mar	2017	ROS	Yes
Bayonne Energy Center II	132	Nat gas	May	2018	NYC	Yes
CPV Valley	650	Nat gas	May	2018	ROS	Yes
Tallgrass Solar (Shoreham Solar Commor	25	Solar	June	2018	LI	Yes
Arkwright Summit	78	Wind	Oct	2018	ROS	Yes
Copenhagen Wind Farm	80	Wind	Nov	2018	ROS	Yes
Economic Retirements in NYC	340			2019	NYC	Yes
Cricket Valley Energy Center	1100	Nat gas	Mar	2020	ROS	Yes
Economic Retirements in NYC	650			2023	NYC	Yes
Total	4,490					

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

PJM

SUMMARY

PJM will conduct the Base Residual Auction (BRA) for the 2021/22 RPM Delivery Year next month, with the auction opening on May 10 and closing on May 16. Results will be posted on May 23. PJM posted updated parameters for the auction at the end of the day on April 13. Compared to the parameters for 2020/21, the Reliability Requirements are generally lower due to a decline in the forecasted peak load. The Net CONE values used to the set the Variable Resource Requirement (VRR) demand curves are higher for all Locational Deliverability Areas (LDAs) due to a slight increase in the inflation-adjusted Gross CONE values and a significant decrease in the energy and ancillary services (E&AS) deduction. The import limits also changed substantially for a few LDAs, increasing for COMED, while dropping for ATSI, PSEG, and PS North.

Other major drivers for the auction results will be:

- Planned retirements of capacity announced since the last BRA;
- Potential additional new entry;
- Market rule changes; and
- Potential for changes in bidding behavior.

ESAI's base case forecast includes a slight increase in the clearing price for the RTO due to reductions in supply that are expected to more than offset lower demand. The MAAC region is not expected to price above the RTO. Within the Eastern MAAC (EMAAC) LDA, price separation is expected between the PSEG LDA and the rest of EMAAC. The PS North LDA is projected to clear at the same price as the rest of the PSEG zone. The clearing price for PSEG (and PS North) is expected to be almost unchanged from the last BRA, but lower prices are expected for the rest of the LDA. The price separation for PSEG is due to a significant drop in the import limit resulting from changes in PJM load deliverability rules and changes in the status of HVDC lines between New Jersey and New York. The EMAAC is forecasted to decline from the price in last BRA due to a lower Reliability Requirement and higher import limit, but still remain above the RTO price. Additionally, the binding import limit for PSEG will result in more capacity in that zone clearing the auction, putting downward pressure on the overall EMAAC price.

A higher import limit is expected to result in a decrease in the COMED clearing price, but high offers for the nuclear fleet in the zone are expected to support continued price separation from the RTO. The DEOK LDA clearing price is not expected to change significantly from the last BRA, with the LDA once again clearing higher than the RTO. Other LDAs with the potential to price above the RTO are BGE and ATSI, though ESAI's base case forecast does not include price separation for either location.

KEY DRIVERS FOR 2021/22 BRA

After significant new entry during the last seven BRAs and repeated drops in the peak load growth forecast, PJM has a significant capacity surplus. In the 2020/21 BRA, 18 GW of capacity offered into the auction did not clear. Of that unsold capacity, more than 15 GW came from generation resources. An additional downward revision to the peak load forecast included in the January 2018 PJM Load Report put further downward pressure on the BRA clearing prices. However, offsetting the decline in demand are several retirement announcements and an expectation for less new entry in this BRA. Changes in market rules for this BRA are less significant than other recent auctions, but generally supportive of higher prices. Each of these factors is discussed below.

Market Rules Affecting the BRA

A few key rule changes since the 2020/21 BRA, as well as continued market responses to prior rule changes are likely to affect the results of the 2021/22 BRA. Specifically:

- ***Reversion of the Minimum Offer Pricing Rule (MOPR) back to the construct that was in place in 2012.*** The details of the MOPR and the impact of the reverting back to the previous version were provided in the Q1 2018 issue of *Capacity Watch*™. The most significant change in terms of potential price impact for this BRA is that all categorical exemptions to the MOPR have been eliminated, meaning that competitive entry and self-supply resources will be subject to an offer floor based on either an estimated class average or a unit specific value determined by the market monitor, based on data submitted by the resource owner. The MOPR will apply to all new generation in LDAs included in the auction (i.e., modeled with a separate VRR curve), but will not apply to new units in the Rest-of-RTO region. The impact for the BRA will be that new supply within LDAs faces one additional hurdle, which may affect the amount offered or the price at which new units in the LDAs are able to offer. This change is expected to be mildly supportive of higher clearing prices.
- ***Incremental Auction rule revisions (awaiting FERC approval)***. PJM has filed tariff changes with FERC that would change the structure of sell offers from capacity released by PJM following declines in forecasted peak load. Rather than PJM sell offers following a graduated curve as has been done in prior Incremental Auctions, the PJM sell offers will instead be at the clearing price of the BRA for the relevant Delivery Year. Because these new rules are intended to limit the profitability of speculative capacity offers, they may discourage artificially low offers from uneconomic capacity resources, supporting a higher clearing price. For prior Delivery Years, due to declines in the peak load forecast and Reliability Requirements, a substantial amount of low cost replacement capacity has been available from capacity released by PJM through sell offers and through bilateral transactions for Excess Capacity Credits. Hence, suppliers have been able to offer new capacity resources that may not be completed in time for the Delivery

Year, or existing resources that are at risk for economic retirement with very limited risk of incurring substantial replacement costs if the resources are not available for the Delivery Year. Under the new rules, suppliers are much less likely to be able to buy replacement capacity at a discount to the clearing price and face more risk of facing a replacement cost above the BRA clearing price.

- ***Continued response to the Capacity Performance rules.*** Although the Capacity Performance (CP) rules were fully implemented for the 2020/21 BRA, market participants may continue to further refine their risk management and bidding strategies in this upcoming BRA. In particular, intermittent and energy limited resources may take less conservative bidding approaches if suppliers have become more comfortable with the penalty risk and likelihood of Performance Assessment Hours. Additionally, suppliers may be more likely to participate with seasonal capacity offers, given that the seasonal supply mechanism was introduced and approved with very little lead time prior to the last BRA.

Auction Parameters

On April 13, PJM released an updated set of Planning Parameters for the 2021/22 BRA. PJM had previously posted preliminary parameters in February. The February posting was generally consistent with the expectations outlined in the First Quarter 2018 issue of *Capacity Watch*™ and included a significantly lower import limit for PSEG and PS North, and a substantial increase in the import limit for COMED. The primary differences in the postings are for the ATSI LDA, likely reflecting the recent retirement announcement for the Davis-Besse and Perry nuclear stations. The most recent parameter posting includes a lower import limit for both the ATSI and Cleveland LDAs.

The tables below show the changes in the BRA parameters between 2020/21 and 2021/22. At the RTO level, the reliability requirement is down by just over 1,100 MW, due to decreases in both the peak load forecast and the IRM value. The amount of load among entities electing to procure capacity resources outside of the RPM auctions through the Fixed Resource Requirement is also similar to the 2020/21 BRA. The market-average EFORd used to translate the auction parameters from ICAP to UCAP terms is slightly lower than the prior BRA.

Price Responsive Demand (PRD) is a construct that allows Load Serving Entities to meet a portion of their capacity obligations through self-supplied demand response. PRD had not been utilized prior to the 2020/21 BRA and some market participants had questioned whether the use of PRD would expand due to increased performance requirements for market-based DR under the CP rules. However, PRD nominations for 2021/22 are almost unchanged from 2020/21.

One parameter yet to be determined is the energy efficiency (EE) add-back for each LDA. Because EE resources participate as supply in the BRA, but are also deducted from the peak load forecast, PJM adds back an amount of demand equal to the quantity of EE certified to participate in the BRA. This value is not known until the deadline for EE verification, shortly before the auction opens. ESAI has assumed the EE add-back values for each LDA will be equal to those applied for 2020/21 and that offered EE supply will also remain at the same level. Changes in the level of EE participation will not have a substantial impact on the clearing price, however, since the EE add-back will change by an approximately equivalent amount.

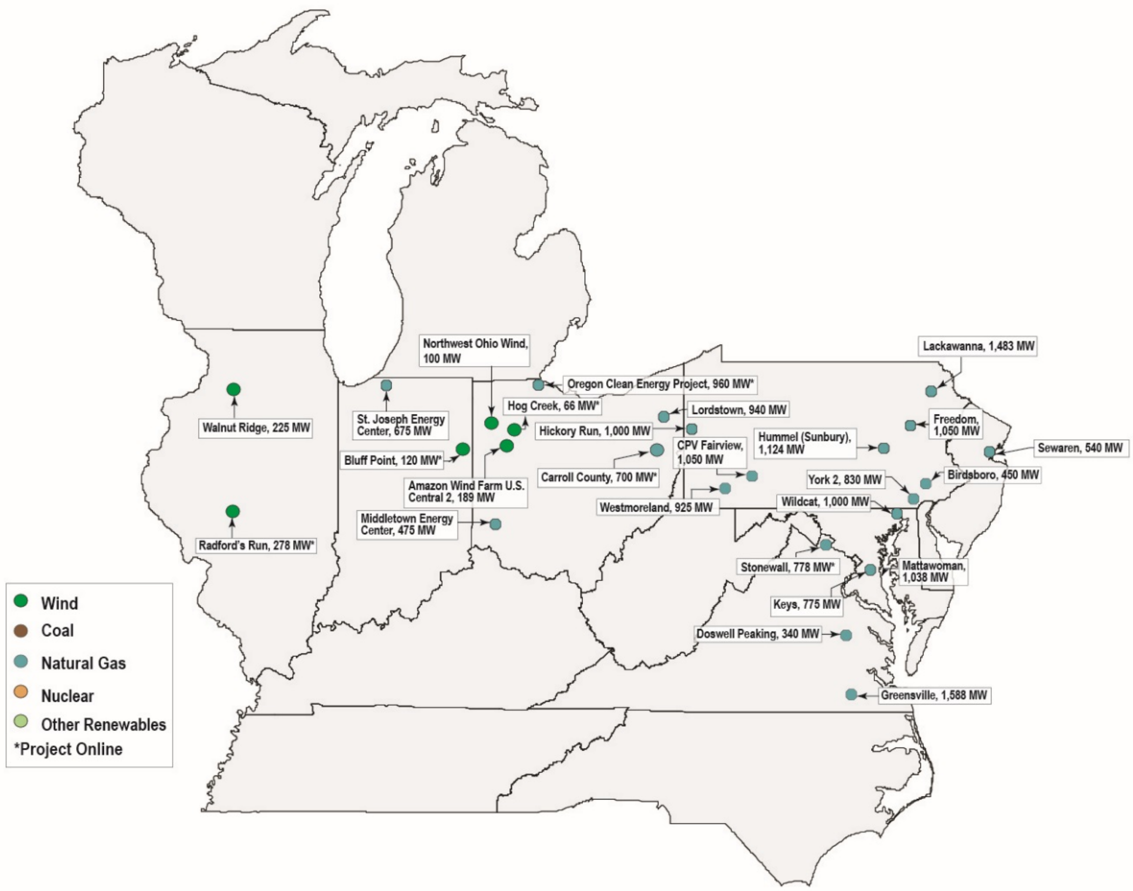
Table 10: RTO Reliability Requirement

	2020/21	2021/22	Delta
Peak Forecast (PJM Load Report)	153,684	152,363	(1,321)
Preliminary Forecast Peak Load for BRA	153,915	152,721	(1,194)
Installed Reserve Margin (IRM)	16.6%	15.8%	
Pool-Wide Average EFORd	6.59%	5.89%	
Forecast Pool Requirement (FPR)	1.0892	1.0898	
Reliability Requirement	167,644	166,436	(1,209)
Total Peak Load of FRR Entities (est.)	12,201	12,107	
Preliminary FRR Obligation	13,289	13,194	
Reliability Requirement adjusted for FRR	**154,355**	**153,241**	**(1,114)**
EE Addback (UCAP, est.)	2,433	2,433	
Nominated PRD Value	558	510	

The 2021/22 Net Cost of New Entry (CONE) values for each LDA have increased from the 2020/21 BRA values, as shown in Table 11. The Net CONE values are used to determine the y-axis price values for each point along each VRR curve. Through a quadrennial process, PJM estimates a Gross CONE value equal to the annual levelized cost of building a new peaking generator in each of four PJM regional locations. The Gross CONE values are adjusted each year based on a composite index for power plant equipment and construction costs. PJM also estimates the amount of net revenue from the sale of energy and ancillary services that could be earned by a peaking unit at each location based on a three-year rolling historical average, computed based on actual market prices and assumed operating characteristics for the benchmark peaking unit. The estimated net revenue is called the Energy and Ancillary Service (E&AS) offset. Net CONE, equal to Gross CONE less the E&AS offset, represents the additional revenue required from the capacity market to cover the all-in costs of a new unit.

For 2021/22, the annual index adjustment resulted in a slight increase in Gross CONE for each location. The change in the E&AS offset was more substantial. The three-year period used to calculate the E&AS net revenue for 2021/22 includes 2015 through 2017. Because the period used to calculate the value for 2020/21 had included the Polar Vortex winter of

Figure 17: Select ESAI Project Evaluation Program Projects



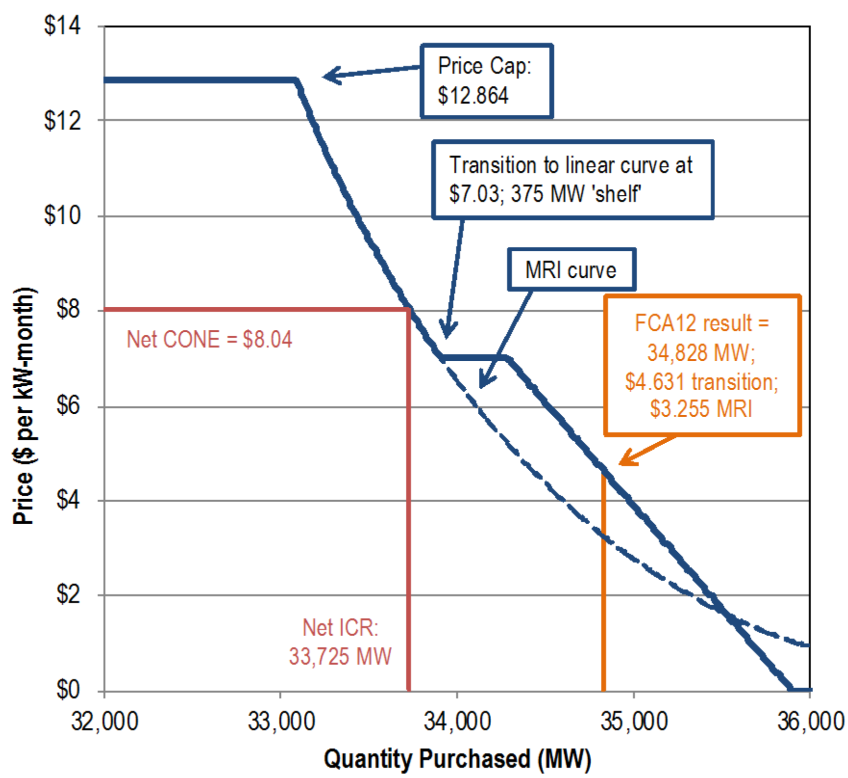
New England

REJECTED DE-LISTS PUSH DOWN FCA12 PRICE TO $4.63/KW-MONTH

ISO-NE held its twelfth Forward Capacity Auction (FCA12) on February 5-6, 2018, procuring capacity for June 2021 through May 2022. FCA12 yielded the lowest clearing prices since the end of administrative floor prices in FCA7, reflecting once again a persistent capacity surplus in the region.

The system-wide clearing price was $4.631 per kW-month (below the $5.50 dynamic de-list bid threshold) for a cleared amount of existing and new resources of 34,828 MW, which is 1,103 MW above the 2021/22 installed capacity requirement (ICR) of 33,725 MW (net of Hydro-Québec interconnection capability credits (HQICCs)). The system-wide price cleared on the linear portion of the FCA12 transition demand curve. Recall that the system-wide transition curve follows the marginal reliability impact (MRI) convex demand curve for prices above $7.03/kW-month. The transition curve then has a “shelf” at the FCA10 clearing price of $7.03. Below the maximum quantity for the shelf, the curve turns linear and follows the same slope as the FCA10 curve. As shown in Figure 1, had the transition curve not been in place and the full MRI curve been applied to the same cleared quantity of 34,828 MW, the clearing price would have dropped to $3.255/kW-month.

Figure 18: FCA12 System-Wide Demand Curve



FCA12 had three zones: an import-constrained zone of Southeast New England (SENE), an export-constrained zone of Northern New England (NNE), and the Rest of Pool zone. Neither the SENE import-constrained zone nor the NNE export-constrained zone separated from the Rest-of-Pool price, resulting in both clearing at the $4.631 price. But, the New Brunswick and HQ Phase II external interfaces needed more excess supply to exit the descending clock auction past this price level, resulting in a lower clearing price for imports over these interfaces of $3.701/kW-month for HQ Phase II and $3.155/kW-month for New Brunswick.

Units Retained for Reliability Force Descending Clock Auction to Continue

The FCA12 descending clock auction was stopped by a dynamic de-list bid submitted by an existing resource, as allowed when the auction price round falls below the $5.50 dynamic de-list bid threshold. However, and for the first time in several FCAs, ISO-NE rejected de-list bids for reliability reasons. The FCA12 clearing price would have been higher (but below $5.50/kW-month) had ISO-NE allowed the dynamic de-list bids submitted for Exelon's Mystic 7 oil-fired steam unit (575 MW) and Mystic 8 gas-fired combined cycle unit (703 MW) to 'clear' and exit the auction. ISO-NE rejected these two de-list bids and retained the units for local transmission security needs (specifically, to prevent thermal overloads on two transmission lines in NEMA/Boston – more details below). ISO-NE did accept a dynamic de-list bid from Exelon's Mystic 9 combined cycle unit (710 MW), which exited the auction.

With the two Mystic units retained for reliability, FCA12 cleared a substantial surplus above the Net ICR purchase requirement. ISO-NE noted that multiple dynamic de-list bids were submitted at $4.630/kW-month. Above $4.630, system-wide supply exceeded system-wide demand; but, at and below $4.630, the capacity withdrawn by the dynamic de-list bids would have resulted in system-wide supply falling below system-wide demand. As a result, the dynamic de-list bids were marginal and set the price of $4.631/kW-month. To allow supply to precisely match demand, the price-setting de-list bids were rationed to a withdrawal quantity that resulted in system-wide supply meeting system-wide demand at $4.631/kW-month, consistent with the auction clearing engine and the "social surplus" maximization algorithm.

Table 25 below shows the FCA12 demand and available supply. In order for the auction to clear with a price of $5.50/kW-month, at least 1,875 MW of supply from existing resources and imports would have needed to withdraw from the auction. If some portion of the 1,576 MW of new generation and demand resources supply was willing to accept a price below $5.50, more existing supply or imports would have needed to withdraw. Our FCA12 outlook of $5.45/kW-month expected static and dynamic de-list bid activity, with the descending clock auction stopping just below the $5.50 dynamic de-list bid threshold. But, the rejection of a large amount of de-list bids for reliability resulted in the capacity forced to stay in the descending clock auction and ultimately lowering the clearing price.

Exelon submitted dynamic de-list bids for the full qualified capacity of its three units at the Mystic generating station – a total of 1,987.5 MW. ISO-NE reviewed them in the following order:

- Mystic 9 (CCGT): 709.676 MW at $5.499/kW-month
- Mystic 8 (CCGT): 703.324 MW at $5.499/kW-month
- Mystic 7 (steam turbine): 574.547 MW at $5.00/kW-month

Because Mystic 9 is larger than Mystic 8, ISO-NE reviewed it first and found no violation, accepting the de-list bid and removing it from the analysis of the subsequent dynamic de-list bids. Mystic 8 was evaluated immediately after Mystic 9 as they were submitted at the same price. ISO-NE found thermal limit violations on two 345 kV cables in the electrical vicinity of Mystic under second contingency (N-1-1) conditions. As the violations are local reliability concerns inside the SENE capacity zone and not on the constrained elements that led to the creation (and form the boundary) of the SENE zone, ISO-NE rejected the Mystic 8 de-list bid and retained the unit for reliability. Under the FCM rules, Mystic 8 will be paid its de-list bid price of $5.499/kW-month for 2021/22, not the $4.63/kW-month to be paid to all other resources (except New Brunswick and HQ Phase II imports).

Table 25: FCA12 Auction Demand and Available Supply

	MW
<u>Auction Demand:</u>	
2021 Forecast Peak Demand (50/50)	29,436
Installed Capacity Requirement (ICR)	34,683
Less: Hydro-Québec Interconnection Capability Credits	958
Net ICR	33,725
Max Demand Curve Quantity at $7.03/kW-month	34,276
Demand Curve Quantity at $5.50/kW-month Dynamic De-lIst Threshold	34,627
<u>Auction Supply:</u>	
Qualified Existing Generation, Demand and Import Resources	34,471
Plus: Total External Interface Capacity Available for Imports (Net of Tie Benefits)	1,680
Total Existing Capacity plus Available Import Capacity	36,151
Qualified New Generation and Demand Resources in FCA	1,576
<u>Minimum MW of de-listed existing capacity + uncleared imports needed to achieve a:</u>	
$7.03 clearing price	1,875
$5.50 clearing price	1,524

Figure 24: Select ESAI Project Evaluation Program Projects

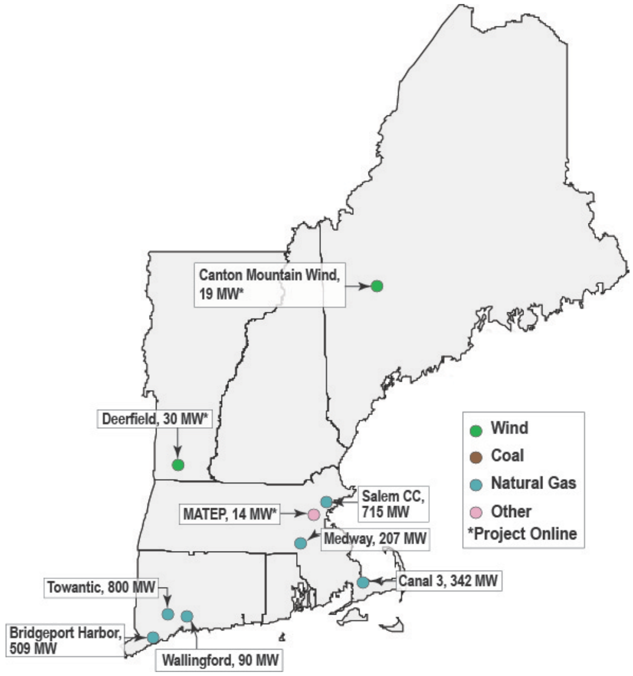


Table 33: New England Capacity Additions

Unit	Capacity, MW	Unit Type	Month	Year	Location	Included in ESAI Base
Jericho Mountain Wind	12	Wind	Jan	2016	NH	Yes
Northfield Mountain Uprate (Unit 1)	22	Hydro	Feb	2016	WMA	Yes
Wyman Uprate (Units 1 and 3)	7	Hydro	Mar	2016	ME	Yes
WED Coventry One	2	Wind	Jun	2016	RI	Yes
Passadumkeag Mountain	43	Wind	Jul	2016	ME	Yes
WED Coventry Six	5	Wind	Sep	2016	RI	Yes
Tiverton Uprate	22	Nat gas	Nov	2016	RI	Yes
Hemphill Expansion	3	Biomass	Nov	2016	NH	Yes
Deepwater Wind	30	Wind	Dec	2016	RI	Yes
Hancock Wind	51	Wind	Dec	2016	ME	Yes
Pisgah Mountain (Clifton Wind)	9	Wind	Dec	2016	ME	Yes
Bingham Wind (Blue Sky West)	185	Wind	Dec	2016	ME	Yes
Milford Power Uprate	33	Nat gas	May	2017	CT	Yes
MATEP	16	Oil	Jun	2017	NEMA	Yes
Granite Ridge Uprate	41	Nat gas	Jul	2017	NH	Yes
Orbit Energy HSAD Biogas	3	Biogas	Sep	2017	RI	Yes
Deerfield Wind	30	Wind	Dec	2017	VT	Yes
Canton Mountain Wind	19	Wind	Dec	2017	ME	Yes
Footprint Power (Salem CC)	674	Nat gas	May	2018	NEMA	Yes
Wallingford Peaker Expansion	90	Nat gas	May	2018	CT	Yes
Lake Road Uprate	50	Nat gas	Jun	2018	CT	Yes
Towantic Energy Center	801	Nat gas	Jun	2018	CT	Yes
Medway Peaking	207	Nat gas	Dec	2018	SEMA	Yes
Bridgeport Harbor CC	509	Nat gas	Jun	2019	CT	Yes
Canal 3	342	Nat gas	Jun	2019	SEMA	Yes
Milford (MA) Power Uprate	53	Nat gas	Jun	2020	WMA	Yes
Newington Energy Center (ST)	38	Nat gas	Jun	2020	NH	Yes
Clear River Energy Center	485	Nat gas	Jun	2021	RI	No
Total	3,780					

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

California

CALIFORNIA CONTINUES EMPHASIS ON GREENHOUSE GAS REDUCTION

The focus of California's energy policy has been on providing leadership and an example for greenhouse gas emissions (GHG) reduction. This focus has translated into reducing fossil fuel use through encouraging transportation electrification, eliminating use of energy from coal-fired generation, and now searching for methods for reducing or eliminating reliance on natural gas generation even to support the operational enhancements needed to maintain reliable service with dramatically increasing levels of variable solar and wind generation. As a result, California is assessing policies to:

- Facilitate improved exchange of low-carbon energy with the Pacific Northwest in response to mid-day solar over-generation and huge morning and evening ramps.
- Identify transmission alternatives that could eliminate the need for existing natural gas generation to meet local reliability needs.
- Provide more incentives and opportunities for battery storage and bulk storage resources.
- Encourage grid regionalization to facilitate better inter-regional coordination and cost savings.
- Build infrastructure for EV charging to encourage massive increases in electric vehicle adoption and support electrification of more heavy duty transportation elements.
- Account for estimated GHG costs in modeling and acquiring more generation.

Our California section of this issue of *Capacity Watch*™ reviews recent actions on this front.

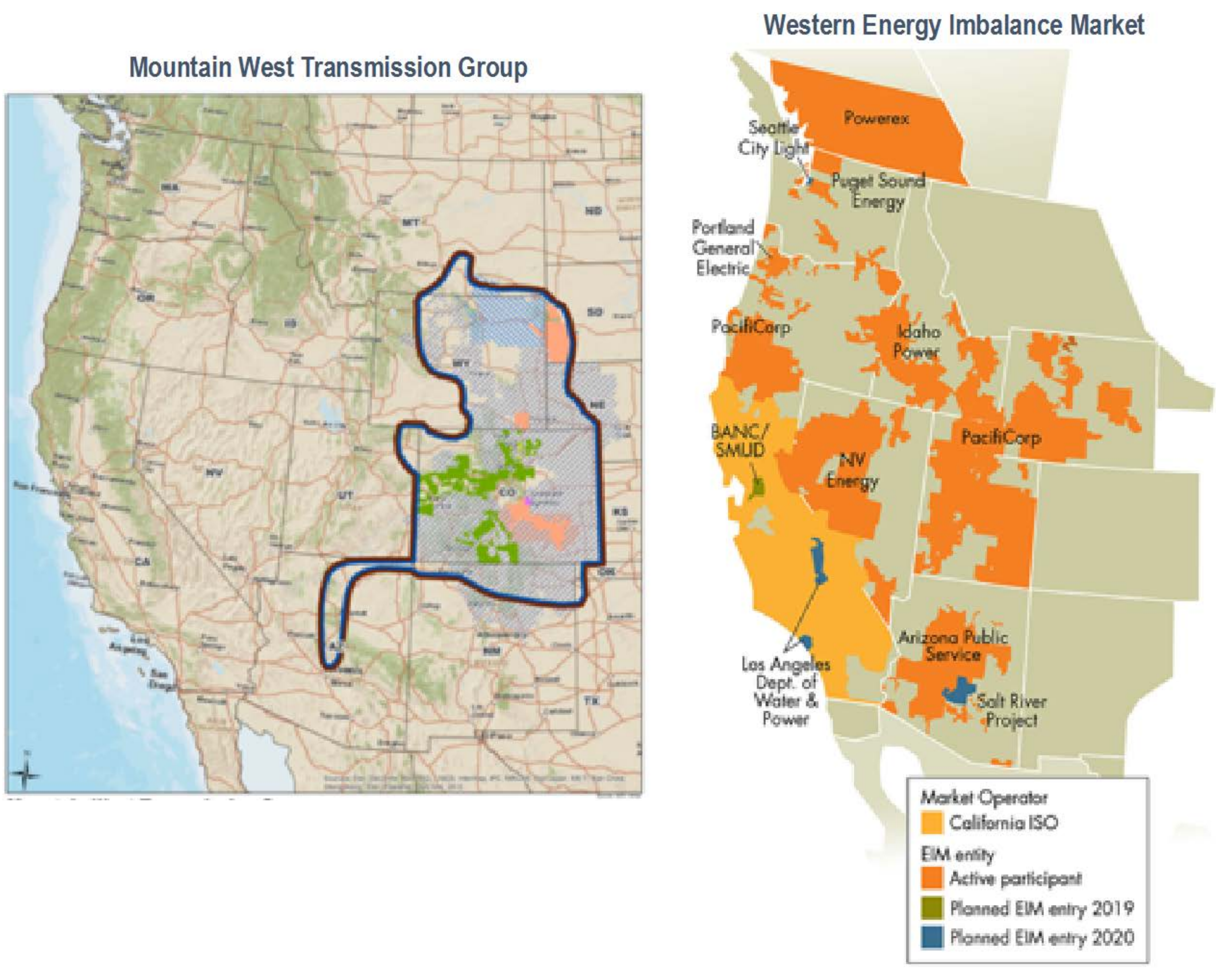
REGIONALIZATION INITIATIVES

In December 2017, Peak Reliability, the reliability coordinator for all of the Western Electricity Coordinating Council (WECC), announced that it had entered into agreement with PJM Connext to explore reliability services and potential wholesale market operations throughout the WECC. The announcement followed on the plan of the Mountain West Transmission Group to join the SPP RTO rather than the CAISO-run Energy Imbalance Market (EIM) – see Figure 1. In response, the CAISO, which has been expanding its EIM to encompass many WECC Balancing Area Authorities (BAAs), gave Peak Reliability a 20-month advance notice of its intent to withdraw from Peak Reliability and provide its own reliability coordinator services, offering to provide the service to any other BAA at about half the cost of Peak Reliability's service. Since then, many other Peak Reliability BAAs have submitted revocable 18-month notices of their intent to leave Peak Reliability, if for no other reason than to not have to pay an ever increasing portion of Peak Reliability's expenses.

Furthering the drama, the president of the California Public Utilities Commission (CPUC) and chair of the California Energy Commission (CEC) asked the CAISO to include a sensitivity in the state's 2018-19 Transmission Planning Process (TPP) to consider increasing transfer ratings of the Pacific AC and DC interties to allow the permanent closure of the Aliso Canyon gas storage field and reduce reliance on gas-fired generation within California to meet reliability needs. Considerations should include:

- Increasing the current dynamic transfer capability limits from 400 MW to some substantially higher credible level supported by engineering analyses;
- Automating of manual controls for essential Bonneville Power Administration (BPA) facilities, primarily in support of sub-hourly scheduling of the Pacific DC Intertie;
- Potentially increasing the capacity rating of the Pacific AC and DC Interties, as well as consideration of intra-California paths that could otherwise be limiting;
- Assigning some resource adequacy value to hydro generation imports that could be shaped through unused storage capacity potentially available in the Northwest.

Figure 25: Mountain West Transmission Group and Western Energy Imbalance Market



The goal is to increase the ability to "illuminate potential benefits (and costs) of building on the long history of exchange between the Pacific Northwest and California entities." The hope is to better integrate the transfer of low-GHG energy between California and the

Northwest, thus helping to moderate the mid-day over-generation problem in California and improve utilization of surplus hydro generation in BPA and British Columbia. The initiative is supported by BPA. The California legislature is also working on regionalization language with AB 813.

To counter discussions between Peak Reliability and PJM Connext, the CAISO has initiated consideration of major changes to its day-ahead Integrated Forward Market, discussed later in this section, that could increase the attractiveness of the CAISO for other parts of the region.

EIM UPDATE

The CAISO posted its fourth quarter 2017 EIM Benefits Report on January 30. The report identified total savings in excess of $33 million, as summarized in Table 25 below. The report further noted reductions in renewable generation curtailment of over 18,000 MW, displacing approximately 7,730 metric tons of CO_2 equivalent, and reductions in flexible ramping reserves needed in all BAAs of 418-432 MW in the upward direction and 504-543 MW in the downward direction.

Table 37: Q4 2017 EIM Benefits Report (millions of $)

Region	October	November	December	Total
APS	$3.72	$3.60	$2.68	$10.00
ISO	$2.35	$1.56	$0.61	$4.52
NV Energy	$2.63	$2.96	$0.86	$6.45
PacifiCorp	$1.71	$2.43	$2.69	$6.83
PGE	$0.99	$0.85	$0.99	$2.83
PSE	$0.99	$0.95	$0.89	$2.83
Total	$12.39	$12.35	$8.72	$33.46

CAISO also announced that Idaho Power and Powerex entered the EIM effective April 4, 2018, expanding the CAISO's real time market to be available to about 55% of the electric load in the Western Interconnection.

RMR UPDATE

The CAISO posted a final draft proposal for Phase 1 of its Reliability Must-Run (RMR) and Capacity Procurement Mechanism (CPM) reform on March 13 and held a stakeholder meeting on March 20. Phase 1, which would be in place for the 2019 operating year, would make new RMR contracts subject to a must offer obligation (MOO) for energy and ancillary services and provide notification to stakeholders whenever a resource informs the ISO if its planned retirement. Condition 1 RMR units would be required to submit market-based bids up to the full RMR capacity during all hours when the unit is physically available. Condition 2 units would be required to submit cost-based bids under the same conditions. If bids up to full capacity are not submitted, the ISO would submit cost-based bids, including start-up, minimum load and energy costs and ancillary service bids priced at $0/MW. The RMR change requires Board approval, which is expected in May.

Phase 2, in place for 2020 Resource Adequacy (RA) cycle, could include the following: