WHITE PAPER

PJM 2019/2020 Capacity Auction Analysis

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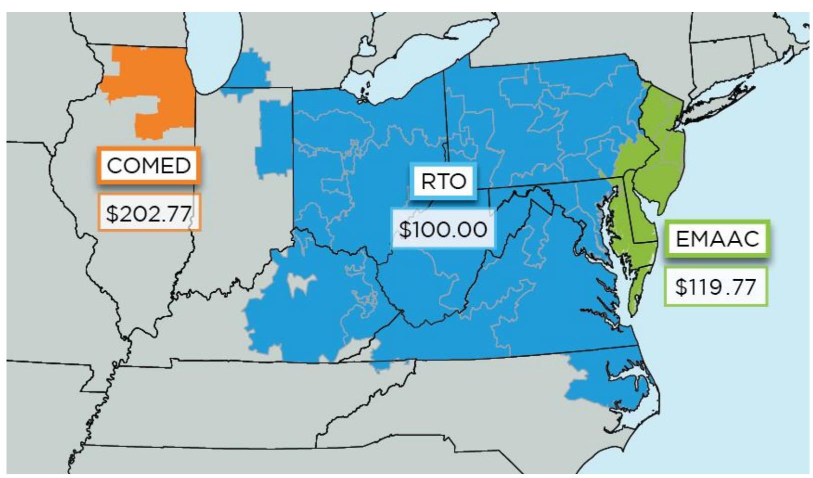
The Bottom Line

1. Prices were lower in the 2019/2020 auction because of PJM's lower peak demand forecast, 5.5 GW of new generation, and lower bids from existing generators.
2. PJM's assumed 30 performance assessment hours in the penalty rate calculation understates units' opportunity cost of being energy only and lowers bids.
3. Capacity prices are expected to increase for 2020/2021 with continued EMAAC and COMED separation.

2019/2020 Auction Results

PJM's 2019/2020 Base Residual Auction (BRA) was a rare auction in which there were no major structural changes to the market since the last auction. However, the recently cleared auction resulted in significantly lower prices—approximately 40 percent lower for RTO—to the surprise of many market analysts and PJM itself. Exhibit 1 highlights the 2019/2020 Capacity Performance (CP) Product clearing prices across PJM. As expected, EMAAC continued to separate from RTO in this auction, although at a significantly lower premium than last year (approximately $20/MW-day instead of $61/MW-day). COMED also saw continued separation, however at a higher premium than for 2018/2019 ($103/MW-day vs. $50/MW-day). This increasing premium resulted from COMED clearing at a similar level as in 2018/2019, while RTO saw a precipitous drop in prices. These low price levels for RTO correspond to a high reserve margin for the region at approximately 22.4 percent[1]. As will be discussed in this paper, this was influenced by lower demand (a lower reliability requirement), more than 5.5 GW of new capacity clearing the auction, and low bids from existing generators compared to expectations based on the CP design.

Exhibit 1: 2019/2020 Auction Results



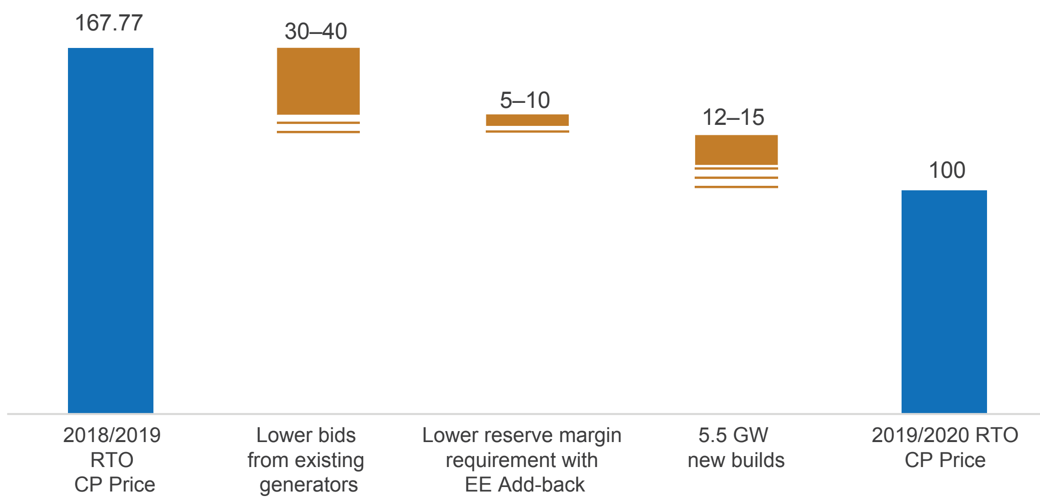
Source: PJM

[1] PJM's reserve margin is equal to (Cleared Resources in ICAP + FRR Commitment)/(Peak Demand + EE add back) – 1. For the 2019/2020 auction the reserve margin is (167,306/(1-6.6%) + 15385.3)/(157188.5+1738.3) = 22.4%. This is in comparison to the 2018/2019 reserve margin of 19.8%.

2019/2020 Auction Analysis

Three primary factors contributed to lower capacity prices in 2019/2020: 1) lower peak demand, 2) 5.5 GW of new generation cleared the auction, and 3) lower bidding from existing generators. Exhibit 2 illustrates ICF's assessment of the relative impact of each of these factors.

Exhibit 2: Factors Influencing CP Product Prices between 2018/2019 and 2019/2020



Source: ICF International

- **Lower peak demand forecast contributed to lower prices—**PJM revised its load forecast model in 2015 related to its treatment of the effect of weather on load, as well as a higher baseline impact of energy efficiency and distributed solar and other forecasting considerations. Consequently, PJM's peak demand forecast for the 2019/2020 auction declined by almost three percent to 157.2 GW from the 161.4 GW forecast used in the previous BRA. This lower peak demand forecast put downward pressure on the capacity prices; ICF estimates the downward impact of lower demand in the range of $10–20/MW-day.

  Because of the change in its methodology around the accounting of energy efficiency programs, PJM also incorporated in this auction an "EE Add-Back" mechanism in its demand curves. The goal of the add-back is to prevent double counting of energy efficiency programs in the capacity market, that is as both a reduction in load and as supply. This new add-back mechanism partially offsets the lower peak demand forecast; ICF estimates that the EE Add-Back cuts the impact of the new load forecast in half to approximately $5–10/MW-day.

- **Economics of 5.5 GW of new builds justified at $100/MW-day—**Despite lower clearing prices, more than 5.5 GW of new generation cleared in the auction. This new generation was concentrated in the rest-of-RTO (3.6 GW), with 1.8 GW clearing in MAAC (only 50 MW in EMAAC). A $100/MW-day price for new combined-cycle generators can be economic if the plant has an optimal location for gas supply, low capital costs, and there is a combination of low return expectations and a strong assumption of favorable spark spread conditions in the future. Also, the bet has to be big. In order to achieve the economies of scale necessary to reach a low capital cost, the unit size needs to be large (greater than 800 MW).

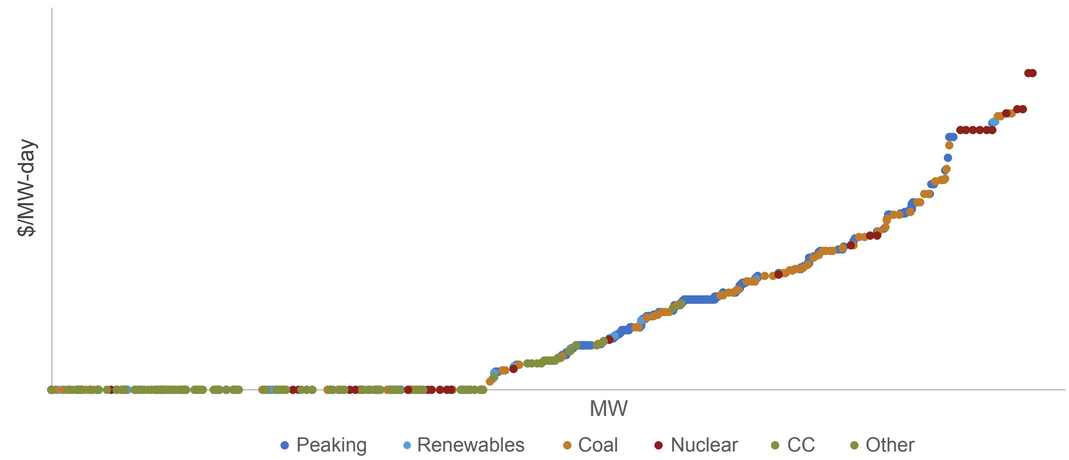
These preconditions are met through the observed shift from 5-series ("7FA") turbines to 7-series ("7HA"). In 2014, combined cycle builds across the United States typically deployed 5-series turbines, but in 2015 and 2016, 7-series and 5-series have been equally deployed. These new 7-series combined cycles are typically larger, allowing the plants to achieve economies of scale in their capital costs. These units also have lower heat rates than 5-series, in the range of 6,400 to 6,600 Btu/kWh. Thus, the new plants are more competitive in the energy market, fueling higher spark-spread expectations.

As noted, in addition to favorable spark-spread expectations, new builds are likely being spurred by favorable financing costs from the current low interest rates and the extension of bonus depreciation passed in December 2015.[2] This extension expires in 2019, so there was likely a push from developers to come online during this auction period. This expiration implies that there may be fewer new units in the next auction if developers expedite timelines in order to come online in 2019. For the same reasons—higher energy margin expectations and lower financing costs—ISO-NE also saw increased new capacity clearing the auction despite lower clearing prices. ICF estimates that the downward impact of new low cost efficient gas capacity was in the range of $12/MW-day to $25/MW-day for PJM.

- **Lower bidding from existing generators—**Slightly more capacity cleared in this auction (167.3 GW vs. 166.8 GW) despite a lower target-installed reserve margin. More capacity clearing at a lower price in this auction implies that there was lower bidding from existing generators. Therefore, in addition to lower demand and a lower cost new supply, lower bidding from existing generators also contributed to the decrease in capacity prices in this auction. ICF believes there are four primary reasons for lower bidding by generators in this auction. First, PJM has suggested that this lower bidding could be due to lower expected CP compliance costs. For example, third-party marketers have helped units secure firm gas contracts at a lower cost than previously thought. Second, decrease in the balancing ratio from 85 percent in the previous auction to 81 percent in this auction resulted in lower bid caps and lower risk premiums[3]. Third, based on ICF's capacity market model, generators seem to assume a low gas price environment going forward, similar to that of 2015. Lower gas price assumptions result in lower bids for gas-fired generators because low gas prices generally translate to higher margins for them. Fourth, generators' expectations for performance assessment hours appears to be lower, given the fact that there were few performance assessment hours observed in the 2014/2015 period across PJM RTO. This would have further put downward pressure on risk premiums included in the price bids.
- **Coal, nuclear, and peaking gas units are marginal in the capacity market—**ICF expects that coal, nuclear, or peaking gas units were marginal in the 2019/2020 auction. Exhibit 3 provides an illustrative CP Product supply curve. Based on ICF's bid expectations, combined cycles had low—close to $0—price bids, based on high energy margin expectation in a low gas price environment. Coal and nuclear units, on the other hand, likely had higher bids, due to lower energy margin expectations and higher fixed costs. Even under low gas prices and higher margin expectations, because of their low dispatch, peaking units have a range of bids based on their fixed costs and CP risk and investment costs. This leads to coal, nuclear, and peaking gas units being the price-setting units in the capacity market.

[2] Bonus depreciation originally expired in 2014; however, in December 2015, the federal government extended the program until 2019. As a result, any capital expense incurred during the 2015 to 2019 period will have an accelerated depreciation ranging from approximately 50 percent in 2015 to 30 percent in 2019. ICF's analysis shows that as a result of the one-year accelerated depreciation for new generators coming online in 2019, the annual capital charge rates could decrease by approximately 1 percent resulting in a $33/MW-day decrease in the bids of new generators.
[3] The Balancing Ratio is adjusted annually by PJM based on historical fleet performance.

Exhibit 3: Illustrative 2019/2020 PJM CP Product Supply Curve



Source: ICF International

- **"Soft" price floor and the opportunity cost of being energy only—**The generators' expectations about the performance assessment hours not only lower bids, they also mean that the soft price floor may be really soft. Bids are conceptually the maximum of expected net fixed costs and the opportunity cost of giving up the opportunity of being an energy-only resource. Resources not cleared in the capacity market, energy-only resources, have the opportunity to earn revenue through performance bonuses during performance assessment hours. By committing in the capacity market, resources give up this opportunity. For this reason, one can consider that a soft floor in the capacity market should be the value of this opportunity cost.

  The price in the most recent BRA is well below the expected soft price floor. This is because the penalty rate, which was set in the June 9, 2015, FERC CP order, appears to have been set too low. Once the penalty rate is set, it does not change in the delivery period. Exhibit 4 outlines the opportunity cost, or potential revenue, that a plant could receive as an energy-only resource in 2019/2020 given a different number of performance assessment hours, if the amount of total capacity is at equilibrium levels. The number of hours actually occurring times the penalty rate determines potential penalties and bonuses a plant could realize. PJM currently calculates the penalty rate based on an assumed 30 performance assessment hours. At this level, an energy-only resource in an equilibrium market could earn up to the Net CONE in bonus payments if all 30 performance assessment hours are realized. If plants believed that the 30 performance assessment hours would be realized, they would bid at this level in the capacity market.

  The problem is that setting in advance a higher number of assumed hours than the actual expected level lowers the penalty rate, creating a discrepancy that lowers the expected penalties, bonuses, and the soft floor. The most recent price is consistent with an approximately 10-hour expectation or one third of the established level. PJM data released on November 16, 2016, illustrates that over the past 10 years, most years have had below 10 performance hours for RTO.

Exhibit 4: Opportunity Cost of Being Energy-Only

2019/2020 Bonus/ Penalty Rate ($/MWh) 2018	Number of Expected Performance Assessment Hours	Opportunity Cost ($/MW-day)
$3,401	30	$279.55
$3,401	15	$139.77
$3,401	10	$93.18
$3,401	5	$46.59
$3,401	3	$27.95

Source: ICF International

- **EMAAC price separation increased—**This trend of lower bidding could have been more prominent in EMAAC. While the region had some downward pressure from a 491 MW increase in the Capacity Emergency Transfer Limit (CETL) and 900 MW decrease in reliability requirement, prices declined by much more than the expected impact from these changes. From PJM's 2018/2019 scenario analysis, an approximate 1.5 GW loosening of the supply/demand balance was expected to lead to CP prices in the range of $185/MW-day. Prices clearing at a $65/MW-day discount to this expectation, with no significant builds in the region, indicates that existing generators' bids dramatically decreased. Bids of existing generators likely put more downward pressure on prices in EMAAC than in rest-of-RTO because EMAAC has a large concentration of gas-fired generators. As previously mentioned, generators likely assumed a low gas price environment going forward when developing their bids, which would increase expected margins for gas units, resulting in lower bids.
- **COMED prices saw a minimal decline—**While RTO saw a 40 percent drop in prices, COMED saw only a six percent decrease, despite a notable decline in the region's reliability requirement (1.2 GW). Thus, while RTO existing generators had lower bidding, COMED saw the same bidding behavior as the last auction. The primary reason for this could be the significant concentration of high fixed-cost units, such as coal and nuclear in COMED's capacity mix. In a low gas price environment, these generators realize lower energy margins and thus have a higher expectation of capacity price requirements going forward.
- **Most demand response (DR) continued to clear as Base Product—**10.4 GW of DR resources cleared in the 2019/2020 auction, and 94 percent of this cleared as Base Product. There were 4.7 GW of DR resources that submitted CP Product offers; however, their CP Product offers were too high to clear. A similar trend was seen in the last auction, when approximately half of the DR resources submitted CP bids and 86 percent cleared as Base Product. ISO-NE—which has implemented pay-for-performance, a similar scheme to CP—has also seen low levels of interruptible load in its capacity market.

Looking Ahead

- **Higher prices going to 100 percent CP—**ICF expects that the RTO price will increase in the next auction. The main driver of higher prices going forward is the transition to 100 percent CP procurement in the next auction. This will increase demand for the CP Product by 27 GW. While some of the previously cleared Base capacity will become available for CP Product, more than half of the DR (approximately 6 GW), which has only bid as Base Product in previous auctions, is not expected to participate going forward. Additionally, resources that have previously submitted coupled offers for Base and CP, but cleared as Base, likely have high CP risk and/or CP compliance costs, meaning that PJM will need to procure more expensive units to meet the CP requirement. There is some uncertainty about what DR will bid, and hence, there is some potential for prices to be above expectation. Shortage incidents this year or before the expected FERC action to fix the penalty understatement (see below) could also cause prices to be above expectation.
- **"Soft floor" and opportunity cost of being an energy-only resource—**The market clearing price is likely to continue to be below the soft floor (approximately $235/MW-day). This is in part because PJM has not acknowledged that there is a penalty rate problem; the issue of the correct number of performance assessment hours to use in setting the rate was not mentioned in the PJM report on the BRA as an issue. FERC has required PJM to file a report on the performance assessment hour level; however, it is not required to file until end of 2017. Thus, action is unlikely before the auction is held in 2019 (for the 2022/2023 commitment period). At that point, PJM may fix the problem and prices could be higher.
- **Prices unsustainable for coal and nuclear—**The implementation of CP was originally thought to be an upside for coal and nuclear units because they already have a firm fuel supply, and capacity prices were expected to increase. However, the lower results of this auction suggest that this upside may be only partially fulfilled. Exhibit 5 summarizes the uncleared capacity in the previous and in the last auction. As can be seen, there was a greater increase in coal and nuclear uncleared than gas. This highlights the deteriorating economics of these capacity types. ICF expects a significant number of retirements from uncleared capacity in the future. Exelon recently announced retirement of Quad Cities, which did not clear the auction and is located in a region with the highest capacity prices, COMED. This highlights that for some of the high fixed-cost base load units in the system, even a price of $200/MW-day may not be enough in a low gas price environment.

Exhibit 5: Uncleared Capacity by Type

	Coal	Gas	Nuclear
2018/2019	4,283	3,135	3,356
2019/2020	7,210	3,523	4,534

Source: PJM

- **Continued EMAAC separation likely—**ICF expects that EMAAC will continue to separate from RTO in the next auction. This region has historically had a higher number of performance assessment hours than rest-of-RTO, leading to higher CP risk premiums for generators. As new builds have been following the low gas prices in the Marcellus regions, we expect few, if any, new builds coming online in the region compared to rest-of-RTO. Because EMAAC generally has higher gas prices than rest-of-RTO, any new builds in this region will likely have higher capacity price requirements than those in rest-of-RTO, further supporting price separation.

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- **Continued COMED separation likely—**With no new capacity expected in COMED and no foreseeable decline in existing units bids, ICF projects that COMED will continue to separate in the next auction. One factor that could have led to COMED not separating in the next auction was the proposed Illinois bill, S.B. 1585 "Next Generation Energy Plan," which would have given zero-emission credits to nuclear facilities. This would have boosted these facilities' economics and likely lowered the "missing money" they need to make up in the capacity market. Lower bids from these units could have led to lower clearing prices or clearing at the RTO level. However on May 31, this bill failed to pass.
- **Seasonal capacity—**PJM has created a seasonal capacity resource task force to address concerns related to the participation of resources with different seasonal availabilities in the capacity market after the transition to 100 percent CP. One idea that may make its way into the market structure is for PJM to aggregate resources with complementary seasonal profiles within the auction-clearing mechanism. This would reduce barriers to entry for seasonal resources, which under the current market structure will need to aggregate with each other before bidding in the auction. If this proposal—or other proposals enabling seasonal capacity to participate as CP—are incorporated into the market, it could likely result in more renewable and DR resource participation. This could potentially put some downward pressure on capacity prices.

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