The Potential Impacts of PJM Market Reforms

By Ilkka Kovanen, Himanshu Pande, George Katsigiannakis, ICF

Shareables

- The current PJM Interconnection (PJM) tariff only establishes non-zero minimum offer price for new gas-fired generation facilities, to protect from uncompetitive bidding and to prevent market price suppression in the capacity market. However, in light of recent state subsidies to generators, the Federal Energy Regulatory Commission (FERC) found the current PJM rules "unjust and unreasonable". PJM filed two alternative market design proposals with FERC to address the market price impacts of state subsidies.
- With a large set of potential nuclear subsidy scenarios and proposed mitigation rules, there is a wide range of possible market outcomes.Testing these scenarios on the 2021/2022 auction produced Regional Transmission Organization (RTO) prices ranging from $70-$482/MW-day[1].

Executive Summary

Low power prices in recent years—resulting from lower gas prices, relatively mild demand, and increased amounts of new combined cycle additions—have created financial difficulties for nuclear generators in PJM, putting many at risk of retirement. Over the past few years, several nuclear generators (such as Three Mile Island, Beaver Valley, Perry, and Davis Besse) have filed for deactivation with PJM.

At the same time, many states have started focusing on reducing carbon emissions, and are recognizing the importance of emissions-free power provided by nuclear generators. States also recognize the workforce and local economic benefits of these facilities. Several PJM states have approved subsidy programs for nuclear generators, or are considering such programs. As a result, the issue of state subsidies in PJM has come to a head in the past year. Subsidy programs for nuclear generators, which accounted for 18% of PJM's installed capacity in 2018, are under consideration in multiple PJM states. While Illinois and New Jersey have the only active subsidy programs, several other states are expected to decide on subsidies in the coming months.

FERC has ruled that the current PJM capacity market construct does not adequately protect against the price impacts of subsidies, but FERC has yet to issue an order on the market changes submitted by PJM on October 2, 2018. Together these factors have created significant uncertainty around the upcoming PJM capacity auction, for the 2022/2023 delivery year.

[1] Please note, these results are not meant to be a projection of the clearing prices for the 2022/2023 PJM capacity auction. They are intended to show the relative price impact magnitudes of the different PJM capacity market proposals and the various nuclear subsidy programs currently under consideration.

Exhibit 1. Overview of PJM's Nuclear Facilities and Subsidy Programs

State	Plant Names	State Nuclear Program/Subsidy Status
Illinois	Braidwood, Byron, Dresden, LaSalle, Quad Cities **Total = 11.7 GW**	IL approved the Zero Emissions Standard program in December 2016, creating Zero Emissions Credits (ZECs) which can be provided by nuclear generators. Currently, Exelon's Quad Cities is the only PJM generator receiving ZEC payments. However, Exelon has announced that the Byron and Dresden generators are also facing financial difficulties. With potential discussions about Illinois implementing a 100% clean energy target by 2030, several or all nuclear units in IL could potentially receive subsidies or out of market payments.
Maryland	Calvert Cliffs **Total = 2.0 GW**	There is currently no nuclear subsidy program under discussion in MD.
Michigan	Donald Cook **Total = 2.4 GW**	MI does not have a nuclear subsidy program, but the Donald Cook nuclear generator is a regulated asset owned and as such is not dependent on market revenues from PJM.
New Jersey	**Hope, Creek, Salem** **Total = 3.8 GW**	NJ approved legislation in May 2018, creating Zero Emissions Credits (ZECs) which can be provided by nuclear generators. On April 18th, the New Jersey Board of Public Utilities approved ZECs for both the Hope Creek and Salem nuclear generators. Following the approval of these ZECs, PSEG has withdrawn their previously-filed deactivation requests for the Hope Creek and Salem generators.
Ohio	Davis Besse Perry **Total = 2.3 GW**	OH legislative leaders have introduced a bill that would provide subsidies to nuclear power plants in OH by creating an Ohio Clean Air Program that rewards clean air resources which minimize emissions from electricity generation. This bill has passed the OH house but is still awaiting approval by the senate.
Pennsylvania	Beaver Valley, Limerick, Peach Bottom, Susquehanna, Three Mile Island **Total = 10.9 GW**	PA is currently discussing a nuclear subsidy program in their state legislature. The proposed bill would create an additional tier in Pennsylvania's Alternative Energy Credit (AEC) program, which will allow nuclear generators to participate. If this program is approved, it will provide additional payments to nuclear generators in Pennsylvania. This could potentially be sufficient to keep the Beaver Valley and Three Mile Island generators online; both have announced plans to retire.
Virginia	North Anna, Surry **Total = 3.9 GW**	VA does not have a nuclear subsidy program, but the North Anna and Surry nuclear generators are regulated assets and as such are not dependent on market revenues from PJM.

Proposed Mitigation Measures in the Capacity Market

On June 29, 2018, FERC ruled that the PJM capacity market construct does not adequately protect against the potential price impacts of subsidized resources. In the same order, they rejected the initial market changes proposed by PJM. On October 2, 2018, PJM submitted their latest proposed changes – the RCO and Extended Resource Carve-Out (Extended RCO) proposals.

In both proposals, resources receiving "actionable subsidies"[2] are subject to a minimum offer price rule (MOPR), which is determined by their resource type and status (new or existing). Subsidized resources can elect to be "carved-out" of the market, in which case they do not receive capacity revenue, and the corresponding load is exempted from making capacity payments. The two proposals differ in how the market price is determined:

- In the Resource Carve-Out proposal, carved-out resources are bid as price-takers (i.e., bid at zero cost) when determining both the market-clearing quantity and price. This is very similar to the status quo in terms of capacity price determinations. The only difference from the status quo is that capacity revenues for subsidized resources are credited back to the load to ensure that load does not have to pay twice for subsidized resources.
- In the Extended Resource Carve-Out proposal, the market-clearing quantity is the same as in the RCO proposal, using a supply curve with carved-out resources bid as price-takers. For the market-clearing price, the carved-out resources are removed completely from the supply curve, while the demand curve is unchanged. This market price approach essentially ignores the existence of carved-out resources.

While the market prices in the Extended RCO proposal are almost certainly higher than in the base RCO proposal, in both cases the carved-out resources receive no capacity revenue and the corresponding load makes no capacity payments. Both designs avoid having load pay twice for capacity, through subsidies and market payments, and avoid giving windfall revenues to subsidized resources, by carving them out or forcing them to bid at MOPR price.

Capacity Prices under Different Scenarios

ICF has run several scenarios, listed below, based on the 2021/2022 capacity auction parameters and resources. For each scenario, ICF used the current market design ("status quo"), and the proposed Resource Carve-Out (RCO) and Extended Resource Carve-Out (Extended RCO) market designs. These scenarios do not account for other changes that will occur for the 2022/2023 capacity auction, such as the new cost of new entry (CONE) and variable resource requirement (VRR) curve recently approved by FERC.

[2] PJM considers any resource where the "primary purpose is to produce electricity" with a UCAP rating above 20 MW that receives a subsidy worth a minimum 1% of total revenues to be a "Capacity Resource with Actionable Subsidy". Self-supplied resources are exempted, subject to the standard net short and net long criteria.

In the status quo scenario, ICF assumes that all subsidized generators bid as price-takers, i.e., bid at $0/MW-day. In the RCO and extended RCO scenarios, ICF assumes that all the subsidized generators elect the resource carve-out option instead of being subjected to the MOPR.

- Base Case – only Quad Cities is subsidized, and no new subsidies are applied.
- Base Case + NJ – the New Jersey nuclear units are also subsidized.
- Base Case + NJ + PA + OH – the Pennsylvania and Ohio nuclear units are also subsidized.
- Base Case + NJ + PA + OH + IL – the remaining Illinois nuclear units are also subsidized.

Exhibit 2 shows the PJM RTO scenario results. Scenario results are based on ICF's estimation of the 2021/2022 supply curve, as PJM does not release individual resource bids.

Subsidy Case	Status Quo Price	RCO Price	Extended RCO Price
Base Case	**140**	140	150
Base Case + NJ	**125**	125	150
Base Case + NJ + PA + OH	**100**	100	210
Base Case + NJ + PA + OH + IL	**70**	70	482*

*At price ceiling of 1.5 times the Net CONE

These prices show no difference between the status quo and RCO cases because any subsidized units are assumed to elect the resource carve-out option. In the base RCO design, there is effectively no difference in terms of market price impact between a carved-out resource and a resource bidding as a price-taker. A scenario where any subsidized units instead bid at their MOPR price would see a less negative impact on market prices, however, there could still be a large impact relative to the Base Case.

Scenario Discussion

The scenario results illustrate the significant impact that nuclear subsidies and market design changes can have on the RTO prices in the PJM capacity auction. There are a few key takeaways from these scenario results:

- If resources bid rationally, there is a limit on how far RTO prices can be depressed. Even with nuclear generators placed as price takers, other resources such as coal-fired generators, new-entrant combined cycles, combustion turbines, and oil/gas steam generators still rely on capacity market revenues to recover their costs.
- The RCO and Extended RCO cases produce very different clearing prices, placing a huge weight on FERC's impending decision regarding the two PJM market design proposals. The two-part market-clearing in the Extended RCO proposal also makes predicting market prices challenging, as it relies heavily on the behavior of infra-marginal resources which are not economic at the RCO clearing price but are

economic at the Extended RCO clearing price. While these infra-marginal resources set prices, they do not actually receive capacity commitments or any revenue from the capacity market. It is unclear how market participants will respond to these new market dynamics, should the Extended RCO proposal be approved by FERC.

Regional Market Dynamics

The PJM capacity market has historically seen a significant variation between the RTO clearing price and the clearing price in some LDAs. Nuclear economics have been a major driver of these price differences.

Exhibit 3 – LDA Clearing Price Premium to RTO ($/MW-day)

Auction	ATSI	COMED	EMAAC	MAAC	SWMAAC
2018/2019	**-**	50	61	-	-
2019/2020	**-**	103	20	-	-
2020/2021	**-**	112	111	10	10
2021/2022	**31**	56	26	-	-

In recent auctions, LDAs where nuclear generators make up significant portions of installed capacity (see Exhibit 4), such as COMED and EMAAC, have cleared at large premiums relative to the RTO price. When this price separation occurs, it can have a depressing impact on RTO prices. This is because the expensive capacity which clears at premium prices in constrained LDAs still contributes towards the overall total RTO cleared capacity, but does not need to be economic at the RTO clearing price.

Exhibit 4 – Nuclear Capacity by LDA in 2021/2022 Auction (ICAP GW)[3]

	RTO	ATSI	COMED	EMAAC	MAAC	SWMAAC
Nuclear MW	**31.2**	2.1	10.5	8.2	13.2	1.7
% of Capacity Mix	**17%**	18%	38%	26%	18%	14%

In some situations, unit-specific subsidies could have little-to-no impact on prices, because they could "push out" another unit which was previously clearing. This likely happened in COMED between the 2020/2021 and 2021/2022 auctions, following the approval of ZECs for Quad Cities. As COMED has several large nuclear generators, clearing Quad Cities–which cleared in 2021/2022 after not clearing for several auctions–simply reduced the cleared quantity for the other nuclear generators. This explains why this subsidy had no apparent impact on COMED prices.

[3] Excluding Donald Cook, which is an FRR resource.

Regional dynamics are particularly important in the Extended RCO case. Individual zone capacity pricing is more sensitive to carve-out than the overall RTO price. This is mainly because there is a large amount of uncleared capacity on the RTO level, which could potentially offset the MWs of carved-out resources. However, this is not the case for every LDA, as shown in Exhibit 4.

Exhibit 5 – Uncleared Capacity by LDA in 2021/2022 Auction (UCAP GW)

Capacity	RTO	ATSI	COMED	EMAAC	MAAC	SWMAAC
Offered	186.5	12.0	27.9	32.0	73.6	12.1
Cleared	163.6	8.0	22.4	29.3	67.4	10.1
Uncleared	22.9	4.0	5.6	2.8	6.2	2.0

Exhibit 6 – Price Ceiling (1.5*Net CONE) End Quantity by LDA, Net of CETL (UCAP GW)[4]

RTO	ATSI	COMED	EMAAC	MAAC	SWMAAC
156.8	7.4	21.3	27.9	62.1	6.4

[4] This is the last point at which the VRR Curve prices are at the price ceiling of 1.5 times the Net CONE. These values assume that the LDAs use their entire CETL.

For example, if both Pennsylvania and New Jersey subsidies are approved, then potentially all the nuclear generators in EMAAC could be carved-out and removed from the supply curve. While EMAAC resources cleared over 29 GW of capacity in this past auction, removing the nuclear generators could drop the available EMAAC capacity to about 24 GW[5]. Based on the 2021/2022 VRR Curve, EMAAC needs around 28 GW of internal capacity to clear the auction for prices to be below the price ceiling of 1.5 times the Net CONE (see Exhibit 6).

EMAAC is not the only zone with a significant amount of nuclear capacity, relative to the total installed capacity. Both COMED and MAAC are in a similar situation.

ICF believes that this dependence on nuclear capacity has been a primary driver for both COMED and EMAAC separating in previous capacity auctions. Absent significant additional subsidies or other resource additions, ICF expects this will continue to drive separation for both LDAs. However, depending on the level of additional subsidies and depending on the market design that is ultimately implemented, the magnitude of price separation may change going forward.

[5] In the 2021/2022 capacity auction resource model put out by PJM, EMAAC has 8.2 GW (ICAP) of nuclear capacity. This translates to at most 8.2 GW (UCAP) for these resources, assuming a minimal EFORD% and no incremental capacity additions. Subtracting 8 GW from the 32 GW of offer UCAP in EMAAC from the 2021/2022 gives around 24 GW of non-nuclear capacity resources in EMAAC.

One additional option that is available to states when subsidizing resources is to have the load-serving entities (LSEs) within the state elect the FRR (Fixed Resource Requirement) Alternative for their capacity requirements. While PJM requires every LSE to follow minimum reserve targets, LSEs are free to allow PJM to manage the capacity procurement–through the Reliability Pricing Model and the annual Base Residual Auctions–or to manage their own capacity procurement through the FRR Alternative. When an LSE elects to FRR, their load is removed completely from the capacity market, along with any resources used to meet their capacity requirements.

For example, a state like New Jersey could direct all the LSEs in NJ to elect the FRR Alternative, and provide capacity revenue to local resources via some state-run market mechanism or through bilateral contracts. This gives states the freedom to procure capacity and make resource decisions as they see fit, without requiring a complete re-regulation of the electricity sector. The impact of FRR Alternative is uncertain and it will depend upon the location (LDA or RTO) and the specifics of the supply-demand balance of the entity selecting the option.

Impact On Merchant Generators

Both the base RCO proposal and the Extended RCO proposal are improvements on the current market design. In the worst case, the base RCO proposal will not cause prices to be any more depressed than the status quo design, and due to the inclusion of a MOPR may result in some price improvement should some subsidized resources not be carved-out. However, the primary upside comes from the Extended RCO proposal.

The Extended RCO could result in significantly higher capacity prices, depending on the specific LDA and the number of subsidized resources which are carved-out. Merchant resources in areas with elevated prices would see a larger contribution from capacity revenues to their gross margins. The Extended RCO proposal has a lot of upside for peaker-type resources, which already make most of their revenue from the capacity market.

The Extended RCO proposal may incent new capacity construction due to higher capacity prices, though these prices are primarily a result of the specific market construct. As such, it is uncertain how developers and investors will respond to these prices.

Should the Extended RCO proposal be adopted, it is unclear how the two-stage market dynamics will impact long-term decision making and bidding strategies by merchant resources. At present, the PJM market has very high amounts of uncleared capacity. In the Extended RCO proposal, these unclear resources set the market-clearing prices, but do not actually clear the market and, as such, receive no capacity revenue. If these dynamics result in further resource retirements, there could be some energy market upside as the overall system reserve margin tightens.

The Potential Impacts of PJM Market Reforms

Visit us at icf.com/work/energy

For more information, contact:

Ilkka Kovanen
ilkka.kovanen@icf.com +1.571.459.4180

Himanshu Pande
himanshu.pande@icf.com +1.703.218.2726

George Katsigiannakis
george.katsigiannakis@icf.com +1.703.934.3223

twitter.com/ICF
linkedin.com/company/icf-international
facebook.com/ThisIsICF

About ICF

ICF (NASDAQ:ICFI) is a global consulting services company with over 7,000 full- and part-time employees, but we are not your typical consultants. At ICF, business analysts and policy specialists work together with digital strategists, data scientists and creatives. We combine unmatched industry expertise with cutting-edge engagement capabilities to help organizations solve their most complex challenges. Since 1969, public and private sector clients have worked with ICF to navigate change and shape the future. **Learn more at icf.com**.