BATES WHITE
ECONOMIC CONSULTING

Healthy Competition

An Assessment of the Value of Robust Markets for Advancing Clean Energy Policy, and the Costs and Risks of Legacy Power Plant Subsidies

July 2020

In the preparation of this report, Bates White, LLC has relied on data provided by S&P Global Market Intelligence. Under the terms of its contract, S&P Global requires that we include the following Disclaimer:

Table of Contents

List of Figures

List of Tables

I. Executive Summary

Centralized competitive wholesale markets for electricity have facilitated substantial changes in the electricity sector over the past two decades, including large scale additions of wind and solar generation, reduced reliance on coal generation, and market participation by demand side resources, as well as technological innovations such as battery storage. Low wholesale energy prices driven by falling natural gas prices and increased renewable generation have been a boon for consumers, but the rapid pace of change has induced some states to pursue policies to prevent or delay the retirement of certain high-cost generation resources, including coal and nuclear power plants.

Narrowly-targeted programs aimed at propping up legacy power plants unable to cover their costs in a competitive market are economically inefficient, costly to ratepayers and/or taxpayers and disproportionately beneficial to specific companies. Even when framed as policies to reduce carbon dioxide (CO2) emissions, such programs are inefficient, because they eliminate compliance flexibility. Rather than specify a goal—e.g., emission reduction—and allow competition to determine the most cost-effective way to achieve the goal, recent subsidy programs have aimed at a particular result: keeping certain high-cost generators from retiring.

The first major initiatives of this type were Zero Emission Credit (ZEC) programs in New York and Illinois, both of which are targeted at keeping certain in-state nuclear power plants, which the owners said were uneconomic, from retiring. Other states have since introduced or proposed other programs to forestall the retirement of costly nuclear or coal-fired generators that cannot cover their costs in the competitive markets. The most prominent ZEC programs have been designed to apply only to power plants that are: nuclear-fueled, located in-state, and are purported by the owners to be uneconomic.

Policies channeling support to existing, uneconomic generators undermine other superficially aligned policies—including those aimed at expanding new renewable generation, storage, energy efficiency, and demand response. The subsidized generating resource, which would otherwise not be able to compete and stay in business, can effectively "dump" its products into the energy and capacity markets at below actual cost, reducing the market prices that other generators, including new renewable resources, receive. These narrowly-targeted preference subsidies consequently *increase* the cost of supporting new renewable generation, because the required net support above available wholesale market revenues is that much greater. Ultimately, market competition for the lowest cost resources is replaced with "competition for subsidies" as additional uneconomic resources seek preferential treatment.

Recent initiatives to correct the distorting effects that such state policies have on wholesale power markets have prompted consideration by some states of opting out of the PJM capacity market, specifically by pursuing a Fixed Resource Requirement (FRR) alternative, allowed under the PJM tariff. This would likely be a costly alternative that would impede competition, make it more costly to implement state environmental policies, and ultimately increase costs borne by electricity consumers.

An analysis of potential impacts for one PJM jurisdiction where the FRR alternative is under consideration—the ComEd Zone—indicates that the cost of opting out of the PJM capacity market could be greater than $400 million annually, with about $140 million of this annual cost increase being borne by residential customers.

Subsidies, or alternatives such as an FRR, aimed at keeping costly, uncompetitive legacy generators in operation ultimately work against clean energy objectives because they increase costs and/or discourage investments in new, low- or zero-emitting generation. Money that subsidizes old, high-cost power plants that would otherwise retire for economic reasons represents ratepayer (or taxpayer) funds that could have been deployed directly through competitive markets to support cost-effective resources that promote policy goals.

It does not have to be this way. There is no reason that state policy goals and competitive wholesale markets have to be in conflict. Indeed, competitive markets can and should be harnessed to achieve state policies cost-effectively. State policies that are better-aligned with, and that use the power of, competitive wholesale markets, will produce better results.

States have more cost-effective options with which to pursue carbon emissions reductions, including broad-based CO2 pricing or cap-and-trade programs, such as the Regional Greenhouse Gas Initiative (RGGI), competitive renewable portfolio standards/renewable energy credit (RPS/REC) programs to incentivize investment in new renewable technology, and reliance on competitive wholesale markets to signal economic additions of renewable and low-emitting gas-fired resources to displace and promote retirement of high-emitting coal-fired generation.

The trajectory of rapidly falling costs for wind and solar generation and battery storage and changing technologies points to a time in the near future when such resources—particularly combinations of generation and storage—will be more cost effective than traditional fossil generation sources, at which point they can be supported fully through revenue from the wholesale markets, relieving ratepayers and taxpayers from providing economic support beyond the direct electric value they produce and from bearing the risk of long-term contracts.

Robust, undistorted competitive power markets reduce the reliance of these new resources on direct and indirect policy support, decreasing the costs to consumers.

II. State Policy Goals and Wholesale Electricity Markets

In recent years, US states have accelerated policy goals to promote new technologies for generating and storing zero-emission electricity, supported by participation in robust wholesale markets administered by regional transmission organizations (RTOs). State RPSs, including REC compliance mechanisms, have established specific requirements for new renewable generation. Other state policies, including cap-and-trade programs such as the RGGI, covering ten states in the Northeast and Mid-Atlantic, and California's Cap-and-Trade Program, place limits on CO2 emissions, and provide for buying and selling of allowances, ultimately providing enhanced value to low- and zero-emitting generation.

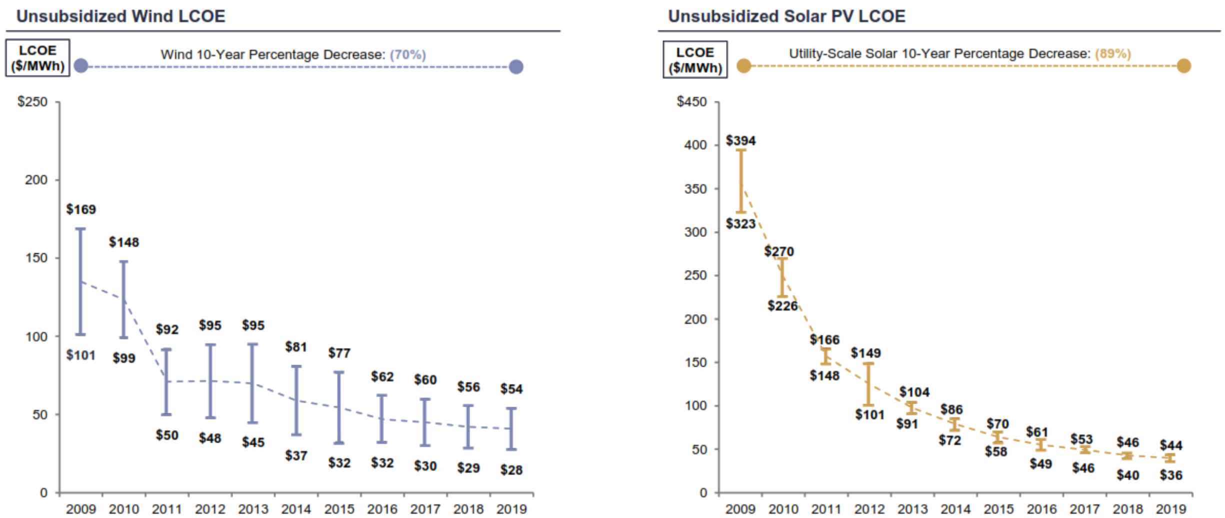
State policies of this sort, which set volumetric requirements, targets or limits, but do not specify particular modes of achieving the desired outcomes, serve to promote economically efficient—i.e., low-cost—solutions to meeting state goals. Competition by resource developers to enter the market involve efforts to improve technology, reduce costs and increase generation efficiency. Effective wholesale electricity markets support this process of finding cost-effective ways to meet state policy goals by compensating generation resources for what they contribute directly to the electric system, and what the system needs to operate reliably and at low cost. Generation resources can provide energy (power produced in the moment), capacity (capability to generate during peak need), and so-called ancillary services (other electrical services that support the reliability of the system) in different quantities and patterns. Centralized wholesale markets aim to set prices for the essential components of electric power, by time period, consistent with the value to the system of a little more (or less) of each component. In providing financial compensation to resources consistent with the value of the product or products being procured, wholesale markets encourage competition in providing those products at lowest cost. Technology-neutral state policy goals level wholesale markets to produce cost-effective results because different resources can aim to contribute both to the policy goal and the most pressing (and therefore most highly-compensated) needs of the electrical system.

The trajectory of rapidly falling costs for wind and solar generation and battery storage points to a time in the near future when such resources—particularly combinations of generation and storage—will be more cost effective than traditional fossil generation sources, at which point they can be supported fully through revenue from the wholesale markets, relieving ratepayers and taxpayers from providing economic support beyond the direct electric value they produce and from bearing the risk of long-term contracts. Figure 1 shows the declining cost of wind and solar generation over the past ten years, based on Lazard's analysis of the levelized cost of energy (LCOE) for utility-scale installation. The LCOE methodology puts technologies with differing investment and operating costs on a comparable dollar per megawatt-hour ($/MWh) basis, and shows a 10-year unsubsidized cost reduction of 70% for on-shore wind, and 89% for solar photovoltaic (crystalline). The current unsubsidized LCOEs for wind and solar generation are below those of new fossil resources, and in many cases below the LCOEs based on going-forward costs of existing coal and nuclear power plants. Lazard estimates that the LCOE for unsubsidized onshore wind projects in 2019 was as low as $29/MWh, approximately 15% below the $33/MWh midpoint of LCOEs for existing coal-fired power plants, and marginally below the midpoint of LCOEs for existing nuclear power plants.[1, 2]

[1] Lazard's Levelized Cost of Energy Analysis – Version 13.0, November 2019; https://www.lazard.com/perspective/lcoe2019.

[2] For existing coal and nuclear plants, the Lazard analysis notes that estimated LCOEs represent marginal costs, inclusive of decommissioning costs for nuclear facilities. For coal units, salvage value is assumed to equal decommissioning costs.

Figure 1: Renewable Energy Cost Decline, Lazard LCOE Analysis[3]



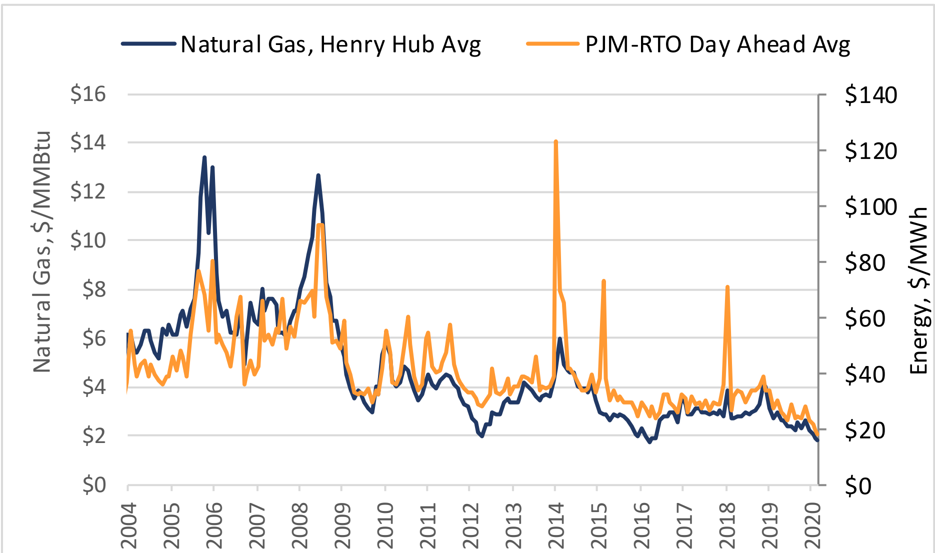
II.A. **Promoting and Resisting Change**

While states are promoting the development of renewable generation and storage, they are also navigating rapid changes in the electricity sector that are national in scope. Most significant of these has been the dramatic expansion of natural gas production from shale fields over the past decade, which has pushed both natural gas and power prices down to persistently low levels. Largely as a consequence of the sustained drop in natural gas prices, new additions of electric generation and operation of existing facilities have skewed more heavily toward gas-fired combined cycle power plants, which has pushed down energy prices in the wholesale markets. Figure 2 shows the pattern of natural gas prices, in dollars per million British thermal unit ($/MMBtu), and of wholesale electric energy prices for the PJM RTO, in $/MWh. PJM is the RTO that administers centralized power markets spanning electric service territories from Illinois to the Atlantic, and that is the focus of much of the discussion of wholesale power markets

[3] *Supra*, footnote 1.

in this paper.[4] Overall, the annual average price of natural gas has decreased by approximately 35% over the last 10 years (2009–2019) while the annual average price of energy in PJM has decreased by approximately 29%.

Figure 2: Natural Gas ($/MMBtu) and PJM Energy Prices (2004–2020)[5]



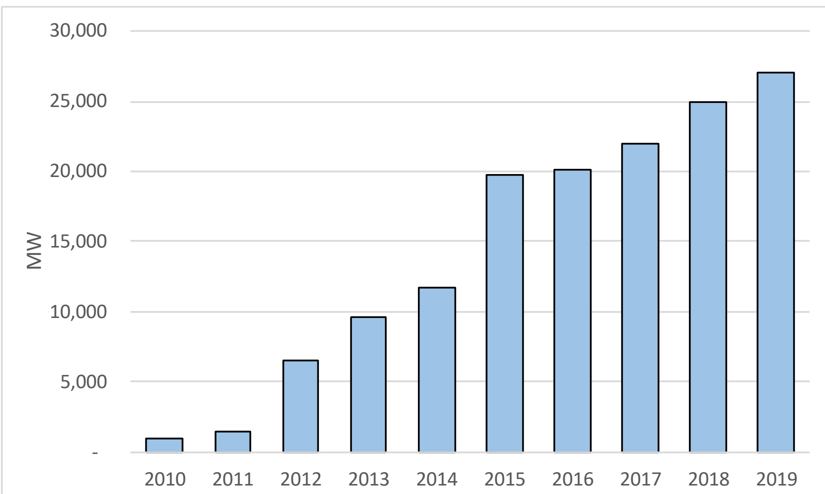
While encouraging the efficient, low-cost production of electric power and sufficient supply are important concerns for policymakers and regulators—and were a central driver of RTO formation—the effects of the shale gas revolution and the accompanying fall in wholesale power prices have been disruptive to legacy generation, particularly older and relatively costly coal-fired and nuclear generators. As described in more detail in the Appendix, most generators in PJM earn revenue selling power into the centralized markets for energy, capacity and ancillary services, or under bilateral contracts with prices closely linked to those markets (since purchases and sales in the centralized markets represent a readily

[4] PJM coordinates the power system in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

[5] Natural gas prices are monthly nominal average spot prices at Henry Hub, as reported by the Energy Information Administration (https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm); PJM energy prices are nominal monthly average Day Ahead prices (all-hour) for the PJM RTO, via S&P Global Market Intelligence.

accessible alternative to contracting). In the past, when gas prices were higher and renewable penetration lower, nuclear and coal-fired generators typically earned a substantial amount of net revenue (revenue in excess of fuel and variable costs) from the energy markets as their cost of fuel was relatively lower compared to gas prices. Net revenue has fallen along with energy prices, and many older, higher-cost plants have been pushed to retire for economic reasons, particularly coal-fired plants that have faced the prospect of costly retrofits to meet environmental rules. Figure 3 shows the cumulative retirement of coal-fired generation capacity in PJM over the past decade, amounting to over 27,000 MW, or about 64% of the total of coal capacity in PJM.

Figure 3: Retirement of Coal-fired Generation in PJM, MW (2010–2019)[6]



Further coal generation retirements over the next decade could be of similar volume. If currently operating coal plants in PJM retire at the average age of recently retired plants—56 years—a further 26,000MW of capacity would retire by 2030.[7]

Producers being forced to exit a competitive market on economic grounds is not a new phenomenon, and in fact is a fundamental indicator that competition is actually functioning. Moreover, the centralized

[6] Installed capacity data from Form EIA-860m, monthly electric generator inventory as of January 2020; https://www.eia.gov/electricity/data/eia860m/.

[7] Based on plant age data from Form EIA-860m (see footnote 6).

electricity markets were formed, and are administered, with the express intention to create prices that accurately value the various components of electricity supply to buyers (ultimately consumers) and provide a clear signal to guide the economic entry of new, efficient resources, and the economic retirement of older, costly resources.

Though economic retirement is a sign of effective competition in well-functioning markets, and by definition serves to reduce the aggregate cost of power production (because lower-cost resources replace retired ones), other factors have caused states to pursue policies to prevent or delay the retirement of certain preferred resources. The first major initiatives of this type were the New York ZEC program, advanced by the New York Public Service Commission in August 2016 as part of its Clean Energy Standard, and the Illinois ZEC program, established pursuant to legislation enacted in 2016. Both ZEC programs are targeted at keeping certain in-state nuclear power plants, which the owners said were uneconomic, from retiring. Nuclear plants receiving ZEC subsidy payments under the respective programs are the Fitzpatrick, Ginna, and Nine Mile Point power plants in upstate New York, and the Quad Cities and Clinton power plants in Illinois, all of which are owned wholly or in part by Exelon Corporation. Recently, Exelon has warned that three other Illinois nuclear plants it owns—Byron, Braidwood and Dresden—are all "showing increased signs of economic distress, which could lead to an early retirement."[8]

Other states have since introduced or proposed other programs to forestall the retirement of costly nuclear or coal-fired generators that cannot cover their costs in the competitive markets.

- In May 2018, New Jersey adopted a ZEC program (in the case of New Jersey, ZEC stands for "zero emission *certificate*") to subsidize purportedly uneconomic in-state nuclear power plants. In April 2019, the New Jersey Board of Public Utilities determined that the Hope Creek and Salem nuclear plants qualified under the program. Hope Creek is owned by Public Service Enterprise Group (PSEG); Salem is jointly owned by PSEG and Exelon.[9]

---

[8] S&P Global, "Exelon Warns 3 More Illinois Nuclear Plants Are at Risk of Early Retirements," February 15, 2019.

[9] https://www.bpu.state.nj.us/bpu/agenda/zec.html.

- Under Connecticut legislation from 2017, nuclear plants at risk of "premature" closure are allowed to compete in the state's RPS solicitation if it is deemed it to be in the public interest. Millstone, owned predominantly by Dominion Energy Inc., and Seabrook, owned predominantly by NextEra Energy Inc., qualified for at-risk designations as of December 2018, and contracts have since been approved for both facilities.[10]

- Under Ohio legislation enacted in July 2019, the Davis-Besse and Perry nuclear plants, owned at the time by FirstEnergy Solutions Corp., which had identified the plants as uneconomic to operate competitively, would receive $150 million of annual payments funded from charges to retail electricity customers.[11] Under the legislation, subsidies would also be provided to two coal-fired plants owned by the Ohio Valley Electric Corp., one of which is located in Indiana.[12]

The ostensible rationale for ZEC programs is to keep certain power plants in operation that the owners would otherwise retire for economic reasons because they are not compensated for the zero-emitting attribute of the energy they produce. The promotion of zero-emitting generation is, of course, a legitimate policy objective. However, the particular methods of advancing such goals can have very different implications for the costs that are ultimately borne by electricity consumers and taxpayers. In general, policies that are less specific about the solution to achieving a broad goal are superior because they allow for flexibility to achieve the goal in the most efficient and least-cost manner. This has been successfully demonstrated in other emissions cap-and-trade programs, perhaps most famously by the US sulfur dioxide (SO2) allowance trading program implemented in the 1990s. The program aimed to substantially reduce SO2 emissions from coal-fired power plants—emissions that were causing acid precipitation damaging forests and water ecosystems in the eastern United States. Rather than a command-and-control regulatory rule—such as requiring a particular control technology or setting a

---

[10] UtilityDive, "Connecticut Moves to Preserve Millstone Nuclear Plant with 10-Year Power Deal," January 3, 2019; https://www.utilitydive.com/news/connecticut-moves-to-preserve-millstone-nuclear-plant-with-10-year-power-de/545133/.

[11] FirstEnergy Solutions Corp. completed bankruptcy restructuring at the end of 2019, becoming Energy Harbor Corporation, which currently owns the Davis-Besse and Perry nuclear plants among other generating assets.

[12] S&P Global Market Intelligence, "Ohio Joins Small Group of States Allowing Nuclear Plant Subsidization," Thursday, July 25, 2019.

uniform emission limit for all plants—the program created a system under which power plants were granted allowances that could be traded (and banked), so that plants could determine a least-cost compliance strategy. Those that could reduce SO2 emissions at relatively low cost would have excess allowances they could sell to other plants for which reductions would be more costly.

The SO2 allowance trading program performed better than anticipated, with SO2 emissions from electric power plants falling by more than a third between 1990 and 2004, though electricity generation from coal-fired power plants actually increased 25 percent over the same period.[13] Effects attributed to the program include technological and process innovations that substantially increased the reliability and utilization rates of SO2 scrubbers, reducing abatement costs, and substantial growth in the use of low-sulfur sub-bituminous coal from the mountain west, factors that were mutually reinforcing.[14] The cost of reduced SO2 emissions under the trading program represented savings estimated at $1 billion per year relative to projected alternative compliance costs.[15] As the large majority of affected generators were traditionally-regulated, such that costs were recovered fully from ratepayers, the reduced compliance costs represented substantial customer savings. The same economic principles apply with respect to CO2 emissions reduction strategies. Broad-based programs with tradeable allowances, such as RGGI, provide compliance flexibility that incentivizes effort, innovation and investment where results are least costly.

ZEC-type programs are problematic from an economic perspective because they eliminate compliance flexibility by effectively specifying the result. The most prominent ZEC programs have been designed to apply only to power plants that are: nuclear-fueled, located in-state, and are purported by the owners to be uneconomic. As noted above, the nuclear plants receiving ZEC payments are all owned fully or in part by Exelon (in Illinois and New York) or by Energy Harbor (in Ohio and previously named FirstEnergy Solutions). Very narrowly-targeted programs of this sort tend to be economically inefficient,

[13] Schmalensee, Richard and Robert N. Stavins, "Lessons Learned from Three Decades of Experience with Cap-and-Trade," MIT Center for Energy and Environmental Policy Research (December 2015).

[14] Burtraw, Dallas, "Innovation under the Tradable Sulfur Dioxide Emission Permits Program in the U.S. Electricity Sector," Resources for the Future Discussion Paper (September 2000).

[15] Schmalensee and Stavins, *op. cit.* (footnote13).

and more costly to ratepayers and/or taxpayers, because there is no possibility for a range of market participants to compete to achieve the desired goal at the lowest cost.

A more economically efficient policy promoting zero-emitting generation would be neutral with respect to participant eligibility, location, and technology. This point was made explicitly in the regulatory proceeding that gave rise to the New York ZEC program. The Independent Market Monitor (IMM) for the New York Independent System Operator (NYISO) submitted comments presenting a comparison of costs of reducing carbon emissions in New York by different means. The IMM estimated that building a new gas-fired combined cycle power plant on Long Island would reduce CO2 emissions (by displacing higher-emitting fossil-fueled generation) at a cost of $20 per ton.[16] The actual cost of the ZEC program ranges from $32/ton to $54/ton, demonstrating that ZEC subsidies to upstate nuclear plants are demonstrably not a least-cost approach to reducing CO2 emissions.

The Connecticut program summarized above, which allows nuclear plants to participate in the state's RPS solicitation, has some mitigating features—specifically, that qualified nuclear plants submit offers that compete with offers from other zero-emission renewable resources. For example, the solicitation in which Millstone and Seabrook offers were selected also selected 300 MW of new offshore wind generation. However, by allowing existing, uneconomic nuclear resources to receive financial support contracts, the Connecticut program promotes economic inefficiency, and hinders renewable generation investment by allowing existing nuclear assets to displace new resource offers. As discussed further below, traditional RPS programs that incentivize new investments in renewable technology on a competitive basis are generally not as problematic as programs that subsidize existing uneconomic nuclear and coal plants.

Policies channeling support to existing, uneconomic generators are particularly problematic because they undermine other superficially-aligned policies—including those aimed at expanding new renewable generation, storage, energy efficiency, and demand response. Subsidies that keep large, costly legacy generators in operation undermine wholesale power markets by distorting the prices at which energy and capacity are bought and sold, and displacing other, more cost-effective sources of power. The

[16] Comments of Potomac Economics, Ltd., NYPSC Case 15-E-0302, page 5.

subsidized generating resource, which would otherwise not be able to compete competitively and stay in business, can effectively "dump" its products into the energy and capacity markets at less than actual cost, reducing the market prices that other generators, including new renewable resources, receive. The narrowly-targeted preference subsidy to uneconomic generators consequently *increases* the cost of supporting new renewable generation, because the required net support above available wholesale market revenues is that much greater. Narrow preference subsidies serve to hinder development of new resources that provide the same emissions reduction benefit, thereby increasing the aggregate cost of achieving the ostensible policy goal of reduced emissions.

In the longer term, the distortions caused by narrow preference policies reduce confidence in the wholesale markets such that other forms of generation needed to meet policy goals or system reliability requirements may no longer be properly incentivized to enter or remain in the market. These distortions undermine the wholesale power markets, weakening a key mechanism for ensuring the economic efficiency and electrical reliability of the bulk power system.

State programs implemented to reverse a locally undesired effect of lower market wholesale prices only serve to further suppress prices, often over a broad region extending into neighboring states, increasing the economic pressure on other legacy generators and encouraging them to seek their own subsidies to stay in business. Ultimately, market competition for the lowest cost resources is replaced with "competition for subsidies" through government influence by the largest donor companies.[17] This has not turned out to be a hypothetical concern, as state programs to support legacy generation have indeed multiplied.

It does not have to be this way. There is no reason that state policy goals and competitive wholesale markets must be in conflict. Indeed, competitive markets can and should be harnessed to achieve state policies cost-effectively. State policies that are better-aligned with, and that use the power of, competitive wholesale markets, will produce better results. As discussed in Section IV below, states have more cost-effective oations with which to pursue carbon emissions reductions, including broad-

[17] *See* "PJM Monitor Rails Against Threat of 'Contagious' Subsidies," *Energy Wire*, March 13, 2017, available at: http://www.eenews.net/energywire/2017/03/13/stories/1060051340.

based CO_2 pricing or cap-and-trade programs, such as the RGGI, competitive RPS/REC programs to incentivize investment in new renewable technology, and reliance on competitive wholesale markets to signal economic additions of renewable and low-emitting gas-fired resources to displace and promote retirement of high-emitting coal-fired generation.

However, as discussed below, there is risk that an unnecessary "fight" between promoting state resource policies and protecting wholesale power markets may lead to particularly negative outcomes for both—more costly implementation of state policies, severely constrained markets, and unanticipated consequences.

III. Action and Response

State efforts to prevent or postpone the economic retirement of legacy generation have had profound effects that continue to reverberate, particularly with respect to the centralized wholesale markets for generation capacity. By subsidizing uneconomic legacy generators, state subsidies allow those generators to bid into the capacity market are prices below their costs and artificially reduce the price received for capacity by all other generators. There has been much discussion recently of the December 2019 Federal Energy Regulatory Commission (FERC) Order to implement an expanded minimum price offer rule (MOPR) in PJM and the impact it will have on the cost of capacity for end users. However, as discussed further below, analysis has shown that the expanded MOPR is not expected to have a significant impact on capacity prices and efforts to pursue alternative capacity procurement mechanisms in response to the expanded MOPR are likely to have the unintended effects of increasing capacity costs and stifling renewable development.

As described more fully in the appendix to this paper—a primer on the design and structure of wholesale markets—generation "capacity" is a distinct aspect of resource supply necessary to provide reliable electric service. While"'energy" refers to the electricity produced and consumed in the moment, 'capacity' refers to the capability of a generator to produce electricity when needed at periods of peak demand or during emergency situations. Since the demand for electricity is highly variable, depending on season and weather, and individual generators may at times be unavailable because of scheduled maintenance or unexpected outage, the electric system needs a volume of generation capacity beyond what is required to generate and meet demand on average during the year.

RTOs such as PJM have established separate markets for energy and capacity, with the capacity market intended to secure needed quantities of capability in the long-term (typically three years in advance) and to incentivize economic investment and retirement decisions, while the energy market is focused on making efficient use of currently available resources in the short-term (e.g., for the following day). Much attention has been focused on the effect of state policies on capacity markets that prevent otherwise uneconomic resources from retiring, though such policies have distorting effects on both capacity and energy markets. In an ongoing regulatory proceeding at the FERC various proposals have been advanced to ensure PJM's capacity market, referred as the Reliability Pricing Model (RPM), continues to send the right economic signals to incentivize and retain the lowest cost resources and the resources needed for reliability while also accommodating state renewable energy goals.

A December 2019 FERC order required PJM to expand the RPM MOPR to mitigate capacity offers of a wider range of resources that receive or are eligible to receive state subsidies, with the definition of subsidy focused on out-of-market payments "supporting the entry or continued operation of preferred generation resources that may not otherwise be able to succeed in a competitive wholesale capacity market."[18] PJM's March 2020 compliance filing would establish minimum offer prices for new entrants to the market and also for existing resources receiving or eligible to receive state subsidies. Floor offer prices for an existing resource would be based on the resource's going-forward, or avoidable, costs, excluding the effect of state subsidies, and reduced by expected net revenue from energy and ancillary services markets. That is, each resource would need to submit a capacity offer at least equal to the net cost (excluding subsidies) that it would incur in order to enter or remain in the market. The compliance filing defines a number of categorical exemptions from the expanded MOPR (consistent with the FERC order), that would be grandfathered from the expanded MOPR either because they were existing or had the requisite interconnection agreements executed: renewable resources participating in RPS programs, demand resources, energy efficiency resources, and capacity storage.

The implication of the FERC order and PJM's compliance filing is that some subsidized resources, either new entrants or existing resources, might be forced to submit higher offers into the capacity market, with the possibility that they will not clear the market and will consequently not receive capacity market payments.

While there is a concern from some that the FERC MOPR order will lead to high capacity prices, analysis of multiple data points actually suggests its impact on prices will be limited. First, PJM's IMM has conducted an analysis of potential effects on the capacity market from expanding the MOPR pursuant to FERC's December 2019 order, and has concluded that no impact is expected on clearing

[18] *PJM Interconnection*, L.L.C., 169 FERC ¶ 61,239 (2019) at P 68.

prices and auction revenues for the main RPM auction for the 2022/2023 delivery year.[19] Second, and related to the IMM's analysis of expanded MOPR effects, most nuclear power plants in PJM are able to more than cover their going-forward costs based on revenues from the PJM wholesale markets. The IMM's 2019 State of the Market Report finds that, of 16 nuclear plants in the region, only Davis Besse and Perry in Ohio would likely fail to cover their costs on a forward-looking basis for the three years 2020 through 2022.[20] All other plants would be expected to earn net revenue in excess of going-forward costs.[21] In other words, for 14 out of 16 nuclear plants in PJM, the default minimum offer price under the expanded MOPR would be $0/MW-day, and there would consequently be no expected effect on those plants from the modified market design. All 14 are large, multi-unit facilities, and these results are consistent with the proposed net avoidable cost rate (ACR) for multi-unit nuclear plants of zero dollars per MW-day that PJM included in its March 2020 compliance filing. The ACR represents the net cost of a plant continuing in operation. If expected energy and ancillary revenues exceed costs, then ACR is zero and keeping the plant operating would produce a net financial benefit while, conversely, retiring the plant would produce a net loss. This is just the sort of metric that a plant owner subject to competition would make regarding whether to retire a plant from service. Retiring a plant only makes sense if the owner can save money from taking the plant out of service. This also establishes that the subsidies to Quad Cities under the Illinois ZEC program, and the anticipated subsidies to Hope Creek and Salem under the New Jersey ZEC program are, in reality, not warranted.

Third, for an owner of multiple nuclear power plants, such as Exelon, the expanded MOPR may have no practical effect on how plants are offered into the PJM capacity market, even if the minimum offer floor were non-zero. In 2014, Exelon's Quad Cities, Byron, and Oyster Creek nuclear plants failed to clear the

---

[19] The Independent Market Monitor for PJM, "Potential Impacts of the MOPR Order," March 20, 2020; https://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_MOPR_Order_20200320.pdf

[20] Monitoring Analytics, LLC (Independent Market Monitor for PJM), "2019 State of the Market Report," March 12, 2020, ("2019 SOM"), pages 352-53.

[21] The 2019 State of the Market Report analysis of nuclear plant net revenue is based on cost estimates from the Nuclear Energy Institute (NEI). Though the analysis showed the Susquehanna nuclear plant with a net revenue shortfall based on the NEI data, the IMM concluded based on additional unit-specific information that the plant is not operating at a loss. 2019 State of the Market Report, page 353.

PJM capacity auction for the delivery period 2017/2018.[22] Though approximately 4,800 MW of its nuclear fleet failed to clear PJM's capacity auction, Exelon reported that its PJM capacity revenues would increase by $150 million in 2017 relative to 2016.[23] Another report, by UBS Securities, estimated that Exelon would earn almost $150 million more in capacity revenue in 2017/18 than it would have if all of its capacity had cleared, because, though Exelon lost revenue for the plants that failed to clear, it gained even more on the rest of its nuclear fleet (more than 20,000MW) because of the resulting increase in capacity clearing prices.[24, 25]

More recently, the IMM identified noncompetitive offers, including high supply offers for nuclear capacity that reduced the volume of nuclear capacity cleared in the 2021/2022 RPM Base Residual Auction (BRA), and that had a significant impact on auction results.[26] In simpler language, nuclear capacity was offered at prices greater than net going-forward costs—i.e., at prices greater than economically justified—and some of that capacity did not clear the auction as a result. This artificial reduction of supply in the auction caused prices to clear at a higher level, increasing the overall cost of cleared capacity. The IMM estimated that the identified non-competitive behavior may have increased overall market capacity costs by more than $1 billion for the 2021/22 delivery year.

Fourth, and lastly, the costs of new wind and solar generation have fallen so far (see Figure 1), and continue to improve in cost and efficiency, such that new resources may well clear the PJM capacity market under the expanded MOPR. The IMM has noted that wind and solar suppliers are confident that these renewable resources are already competitive and will become even more so in the future.[27] The

---

22 Exelon presentation at the Sanford C. Bernstein Strategic Decisions Conference on May 29, 2014.

23 *Id.*

24 *See* "How Exelon Won by Losing," *RTO Insider*, June 3, 2014. Available at: https://www.rtoinsider.com/exelon-pjm-capacity-mkt/.

25 Subsequently, Exelon's Quad Cities and Byron plants were bid into and cleared PJM's transitional capacity auction (for its new "Capacity Performance" capability standard) for the same 2017/18 delivery period, at an even higher clearing price. *See* https://www.rtoinsider.com/pjm-transition-auction-17524/

26 Monitoring Analytics, "Analysis of the 2021/2022 RPM Base Residual Auction: Revised," August 24, 2018, pp 18-19; http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf.

27 IMM, *op. cit.* (footnote 19), page 3.

proposed expanded MOPR would establish default minimum offer prices by resource category, and new resources would be required to offer into the capacity auction at that level (or higher), but the proposed rules also allow sellers to seek unit-specific exceptions to the default prices levels. Sellers thereby have the opportunity to show that they should be allowed to offer at a price below the default minimum, based on actual costs, increasing the likelihood that they clear the market and earn capacity revenue (e.g., if a Seller is more cost-effective than others, it will be allowed to bid into the capacity market at a lower price under the expanded MOPR).

Notwithstanding the considerations just noted regarding the likely limited impact of the expanded MOPR, some states have contemplated an alternative to continued participation in the PJM capacity market under altered terms—specifically, by pursuing an FRR alternative, allowed under the PJM tariff. A state following this course of action would need to establish a procurement mechanism to secure capacity in necessary quantity, and presumably consistent with that state's target mix of resource types. While FERC's response to the PJM compliance filing remains pending, and no particular state plans for exiting the capacity market have been detailed, an unnecessary "fight" between protecting wholesale power markets and promoting state resource policies is fraught with potentially severe consequences for both. Simply put, an FRR will impede competition, make it more costly to implement state policies, and ultimately increase costs borne by electricity consumers.

III.A. **Pulling Out of the Capacity Market Would Be Counterproductive and Costly.**

It would be an understatement to say that the capacity market is unappreciated. It is skeptically viewed by electricity buyers as an unnecessary source of cost, and by certain sellers as ineffective in compensating appropriately for decreased energy market revenue. Yet the value of the capacity market may only be fully acknowledged after its demise.

States contemplating an exit from the market may see this option as providing greater freedom to pursue policy goals, but it would likely come at significant cost. In a competitive wholesale market, generators are compensated based on value provided to the system, not based on assured recovery of costs plus a profit as they are in a regulated market. Alternatives to capacity market participation are likely to look more like cost-of-service regulation than competitive market outcomes, as sellers look to secure long-term assurance of revenues and profits by competing for political influence rather than cost-effectiveness. The alternatives are potentially worse than cost-of-service regulation because they would provide assured cost recovery without regulatory oversight. Under PJM's FRR alternative, a state must commit to exiting the PJM capacity market for a minimum of five years. Such long-term commitments will necessarily entail a shift of costs and risks to ratepayers at precisely the time when rapid changes in the industry are magnifying the value to ratepayers of being able to shift course quickly to adopt emerging technologies in the market over time.

It is also important to appreciate that eliminating the capacity market in one part of PJM would diminish the market construct as a whole. It is not reasonable to exit the capacity market and yet expect a replacement bilateral or state-run capacity market at a smaller scale to be comparably liquid and efficiently-priced. Further, as with the potential for a cascade of expanding state programs subsidizing uneconomic resources, which has largely been realized, one state exiting the capacity market increases the potential that other states will pursue a similar course, ultimately making the capacity market non-viable. Such disruption will only serve to increase electricity costs for consumers and reduce reliability.

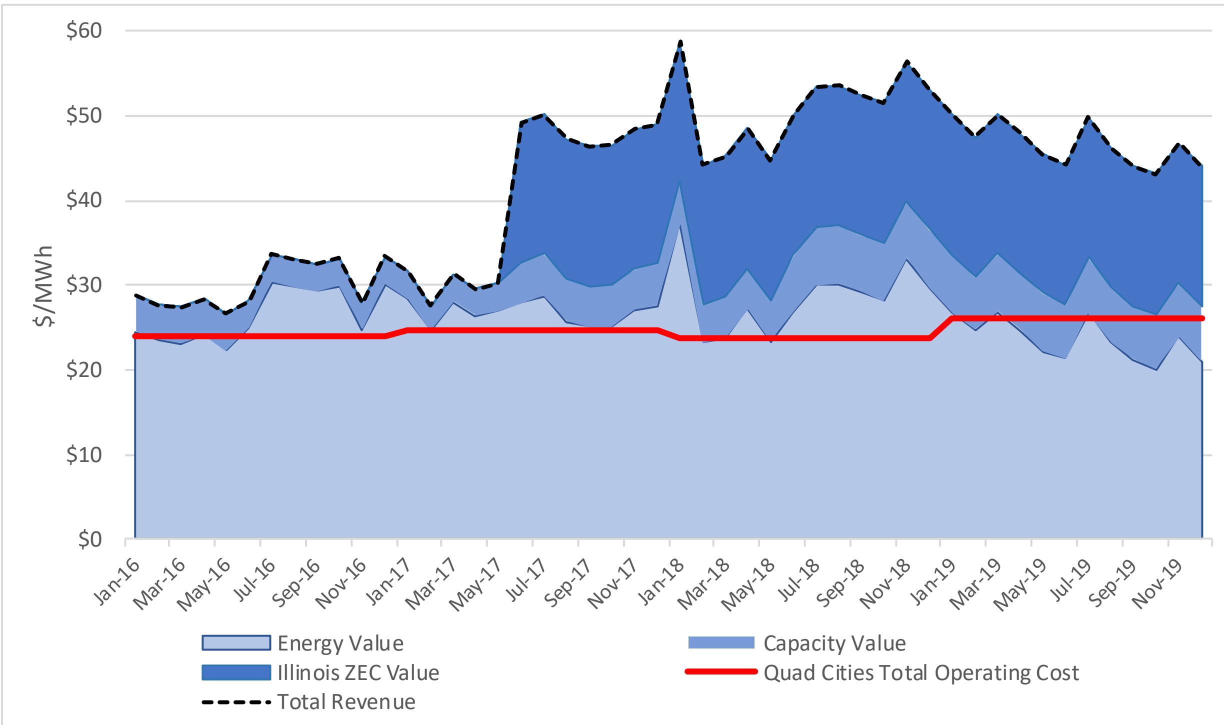
III.B. **Potential Cost of Large-Scale Procurement Outside of the Capacity Market**

Large-scale procurement outside of the PJM capacity market would likely entail increased costs. Returning to the example of Illinois, Exelon receives ZEC payments for its Quad Cities and Clinton nuclear plants located in PJM's ComEd zone and MISO's Illinois zone, respectively, totaling on the order of $200 million annually. Combined with revenue from the energy and capacity markets, ZEC payments have provided the company a substantial margin on the plants.[28] Based on energy market prices alone—i.e., excluding capacity market revenue—Quad Cities has been near to covering its total annual operating costs, including fuel, variable and fixed O&M costs over the past three years. The $16.50/MWh ZEC subsidy provides a comfortable margin in excess of operating costs, as shown in Figure 4. In 2019 the estimated average net profit—revenues over costs—was $20.44/MWh. While the Illinois ZEC program is intended to limit ZEC prices such that total revenues do not exceed a benchmark

[28] S&P Global, "Operating Costs at 3 'At-Risk' Exelon Nukes Run Close to Power Prices," March 5, 2019.

of \$31.40/MWh, ZEC prices are set in advance of each annual delivery period, and reflects forward energy prices. Under this methodology, ZEC prices will continue at the maximum \$16.50/MWh at least through May 2020.[29]

Figure 4: Quad Cities O&M Cost, Revenue Rate from PJM Energy and Illinois ZEC Rate[30]



Based on market data, as well as forward-looking analyses by the PJM IMM and others, subsidies to nuclear plants in PJM are providing more revenue than necessary to cover going-forward costs. On the one hand, this means that an expanded MOPR is unlikely to have any net effect on the PJM capacity

---

[29] See Illinois Power Agency's preliminary payment calculation notice for delivery year June 1, 2019 through May 31, 2020 (May 24, 2019); https://www2.illinois.gov/sites/ipa/Documents/2019ProcurementPlan/2019-2020%20Delivery%20Year%20Preliminary%20Payment%20Calculation%20Notice%20%28May%2024%2C%202019%29.pdf

[30] Quad Cities total O&M expenses from S&P Global Market Intelligence. Energy prices are monthly all-hour average day-ahead prices at the Northern Illinois Hub.

market, as the IMM has concluded.[31] On the other hand, it suggests that support from plant owners for pursuing an FRR alternative would be based on an expectation that expected revenue will be at least as great under that approach than under the existing construct—with or without an expanded MOPR.

As noted above, the IMM has identified concerns with respect to high supply offers for nuclear capacity in the 2021/2022 RPM BRA that had a significant impact on auction results. Because generation ownership is relatively concentrated in PJM, the IMM finds that "[m]arket power is and will remain endemic to the structure of the PJM Capacity Market," but also concludes that "a competitive outcome can be assured by appropriate market power mitigation rules."[32]

While not perfect, the PJM capacity market provides a structure in which market power arising from concentrated resource ownership can be addressed and mitigated in order to ensure competitive results. This currently occurs through scrutiny of offer behavior—both prices and quantities—in locations where transmission constraints limit competition such that some market participants may have the ability to unilaterally affect auction outcomes. PJM's tariff provides detailed market power mitigation rules that promote competitive outcomes, and PJM, the market monitor and other market participants continually evaluate operation of the capacity market and consider improvements to mitigation rules.

It is far more difficult to achieve such mitigation in a world with state-by-state procurement, because the market power of local suppliers tends to be magnified—particularly if a requirement or preference for in-state generation is applied. For example, while Exelon owns approximately 12% of the generation capacity in PJM as a whole, it would control nearly 40% of the generation supply in a ComEd FRR market. Owners of legacy generation resources—both nuclear and coal—have been successful in securing subsidies for power plants that are otherwise not economic in a competitive market with increasing renewable generation and efficient generators able to take advantage of low natural gas prices. It is only to be expected that legacy plant owners will seek, through influence and market power, to secure advantageous terms in any move to state-directed procurement as an alternative to the RPM market.

[31] IMM, *op. cit.* (footnote 19).
[32] IMM, *op. cit.* (footnote 26), page 2.

III.B.1. Estimated Cost of a ComEd FRR

As an alternative to continued participation in the PJM capacity market, ComEd/Exelon could instead pursue an FRR using a combination of self supply and bilateral contracts to meet its reliability requirement. The most recent capacity clearing price for the ComEd local deliverability area (LDA) was $195.55/MW-day in the auction for the 2021/22 delivery year. This was near the maximum zonal price in PJM ($204.29/MW-day for the PSEG Zone), but significantly below the Net Cost of New Energy (Net CONE) of $344.36/MW-day for the ComEd LDA, with Net CONE representing the estimated cost of building new capacity to meet an incremental capacity need, less expected net revenue from the PJM energy and ancillary services markets. The $195.55/MW-day clearing price was also about 23% below the offer cap applicable to the ComEd LDA, which is $254.40/MW-day. The locational offer cap is one of the mechanisms applied to mitigate the exercise of market power in areas such as the ComEd Zone, where ownership concentration is high and competition is limited by transmission constraints.

Yet after the capacity auction concluded, Exelon reported that the ComEd LDA clearing price was not sufficient to cover the costs of all its nuclear units within the zone. Consequently, it can be assumed that to keep all of the ComEd LDA nuclear capacity in operation under an FRR would require an effective capacity price greater than $195.55/MW-day, and as high as the current offer cap of $254.40/MW-day. Table 1 summarizes the alternative capacity cost under an FRR at alternative capacity prices, assuming that Exelon would require a higher capacity price than the most recent capacity auction given that the price was not sufficient for the company to clear all of its nuclear plants and assuming the volume of cleared generation capacity in 2021/22 auction.

Table 1: Estimated ComEd FRR Capacity Cost at Alternative Clearing Prices

	Clearing price, $/MW-day	Cleared capacity volume, UCAP MW	Annual cost	Cost increase relative to actual
	(a)	(b)	(c) = (a)x(b)x365	
Actual 2021/22 result	$195.55	22,358	$1,595,826,156	
Alt clearing prices	$210.00	22,358	$1,713,748,365	$117,922,209
	$230.00	22,358	$1,876,962,495	$281,136,339
	$250.00	22,358	$2,040,176,625	$444,350,469

At $250/MW-day, the capacity cost for the ComEd LDA would be $444 million greater than the actual result from the 2021/22 capacity auction. About $138 million of this annual cost increase would be borne by residential customers, based on share of retail sales, or about $38 per customer.

A ComEd FRR would also likely provide a windfall to nuclear capacity in the zone. Only half of the nuclear capacity in the ComEd zone cleared the 2021/22 capacity auction. Assuming all capacity is compensated equally per MW, nuclear revenue under an FRR would be substantially higher. Table 2 demonstrates the effect on nuclear capacity revenue for the alternative FRR capacity prices considered above.

Table 2: ComEd Nuclear Capacity Revenue at Alternative Clearing Prices

	Clearing price, $/MW-day	Cleared nuclear capacity, UCAP MW	Annual Nuclear Capacity Revenue	Increased Nuclear Revenue
	(a)	(b)	(c) = (a)x(b)x365	
Actual 2021/22 result	$195.55	5,175	$369,369,506	-
Alt clearing prices	$195.55	10,378	$740,737,534	$371,368,027
	$210.00	10,378	$795,473,700	$426,104,194
	$230.00	10,378	$871,233,100	$501,863,594
	$250.00	10,378	$946,992,500	$577,622,994

It is important to remember that $250/MW-day is still far below the Net CONE that would be required to support construction of new capacity in the ComEd LDA. In other scenarios in which significant capacity retires, the clearing price could be even greater.

The calculations presented above are simplified, but in fact they correspond closely to results from a more detailed assessment conducted by PJM's IMM of potential effects of implementing an FRR for the ComEd LDA.[33] A similar scenario was evaluated in which ComEd/Exelon would procure its full capacity obligation at the $254.40/MW-day offer cap, which the IMM characterized as reasonable, "[g]iven Exelon's assertions that the current total revenue from energy, ancillary and capacity markets is not adequate for its nuclear plants."[34] Under this scenario, net load charges for capacity in the ComEd LDA were estimated to increase by $414.4 million (23.6%) compared to the results of the 2021/2022 capacity auction. The lower dollar impact in the IMM's evaluation reflects an assumed lower volume of capacity procured, which means that part of the savings is coming from the fact that the ComEd LDA would have fewer megawatts committed to it in an FRR to call upon during high peak demand days, emergencies or an unexpected outage of a large nuclear or coal unit.

A move to an FRR for the ComEd LDA would be expected to result from negotiations between ComEd/Exelon and Illinois, possibly including other capacity owners in the LDA. Based on the claimed need for additional ZEC subsidies to support Exelon's Illinois nuclear plants—Byron, Braidwood, Dresden and LaSalle—the IMM estimates total annual subsidies would be approximately $924.9 million, which the IMM considers is appropriately included in the evaluation of both scenarios.[35] This latter point may be debated. For instance, if it is assumed that Exelon is able to secure the same amount of support for its plants in any future scenario, either through ZEC payments or through compensation from an FRR procurement process, the subsidies would not properly be considered as a consequence of moving to an FRR. It is equally true, however, that it cannot be assumed that an FRR would avoid the

[33] Monitoring Analytics (PJM IMM), "Potential Impacts of the Creation of a ComEd FRR," December 18, 2019; https://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf.

[34] *Id.,* page 1.

[35] *Id.*, page 14.

cost of additional subsidies. Indeed, Exelon's ability to influence the procurement process, exert supplier market power, and pursue additional nuclear subsidies might well be expected to increase the cost of an FRR relative to continue RPM participation.

III.B.2. Additional Long-Term Considerations of an FRR

It is important to appreciate that the IMM's analysis of a ComEd FRR is narrowly focused on a single LDA and uses a single capacity delivery year to evaluate cost impacts. Moving to an FRR would likely have more substantial impacts when considered over the longer term. Each RPM BRA auction selects capacity and establishes an applicable revenue rate for a single delivery year three years in the future. Capacity resources receive no revenue assurance for other periods. As a consequence, cost and operational risks are borne predominantly by generation owners/suppliers rather than end-use customers.[36] State-directed capacity procurement under an FRR alternative would likely need to rely on longer-term contracting for a variety of reasons. Longer-term contracting would simplify administration, provide assurance of meeting state policy objectives over time, and would be preferred by generators seeking greater assurance of cost recovery and profits, outside of a competitive market. The FRR alternative in PJM requires zones that utilize FRR to exit the PJM capacity market for a minimum of five years, further contributing to the need for long-term contracting. An FRR alternative would consequently look more like traditional cost-of-service treatment of generation, relieving some cost and revenue risks from suppliers and moving those risks toward customers. If generation resources are expected to commit to serving state load, and to forego opportunities to sell into competitive markets out of state, there would be a strong incentive for suppliers to push for long-term revenue and return assurance, something that deregulation and centralized markets were specifically aimed at moving away from.

[36] Much of the electric load in PJM is served in jurisdictions—such as New Jersey, Maryland, Pennsylvania and Illinois—where electric industry restructuring removed generation supply from the functions of local utilities, and from traditional cost-of-service ratemaking. Most generators in PJM are reliant on wholesale market revenue, and have no regulatory assurance of recovering their costs in full. There are some notable exceptions, such as Virginia, where utilities such as Dominion Energy remain vertically integrated (owning generation, transmission and distribution facilities).

A related issue is that locally-focused procurement outside of the PJM capacity market presents challenges in achieving a cost-effective mix of resources, including the right amount of flexible (typically gas-fired) resources necessary to accommodate additional wind and solar generation. Reliance on competitive wholesale markets does not guarantee that an optimal mix of resources is achieved, but robust price signals from a liquid market incentivize investment where it is most needed, and if market circumstances change—as they are with increasing speed—it is the generator/supplier that bears the risk if the value of a resource to the system, and consequently the revenue the market provides, is unexpectedly reduced.

It should also be noted that the IMM's evaluation of a ComEd/Exelon FRR assumes that the rest of PJM's load-serving entities continue to participate in the RPM capacity market. Yet one jurisdiction opting out of the RPM market may increase the likelihood that others elect an FRR alternative as well, increasing the potential exercise of local market power, and ultimately weakening the RPM construct to the point that the capacity market is eliminated entirely. Such balkanization of the PJM system would exacerbate the potential system reliability effects of planning and procuring capacity without consideration of overall system needs.

Finally, an FRR that increases the amount of uneconomic capacity kept in operation would prevent more cost-effective resources from entering or remaining in the market, and at the same time would keep energy clearing prices lower than they should otherwise be for other, non-subsidized resources, undermining the economics of new renewable resources, and increasing the cost of renewable PPAs and RECs.

The value of robust centralized wholesale markets is perhaps best captured by the fact that some resources do *not* cover their costs, and exit the market. Retirement of coal-fired generation and some nuclear plants (discussed further in the appendix to this paper) is an indicator of the value of the wholesale markets to end-use customers. In a regulated or cost-of-service market, the ratepayers would be responsible for paying for the higher operating costs of continuing to run uneconomic plants, or the unrecovered capital cost of those plants if they are retired even though they are no longer needed. However, in a competitive market, it is the asset owners that bear those costs and are encouraged to retire assets that no longer provide sufficient value to the system to warrant their cost rather than ratepayers being required to continue to pay for uneconomic or retired assets under cost-of-service regulation.

III.B.3. Implications of Local Procurement for System Reliability and the Market Construct

An increased emphasis on procurement of local resources also has implications for the reliability of the electric system. A focus on securing resources to meet state policy goals outside of the integrated markets increases the potential that the resource mix does not account for or meet system needs on a regional or system basis. A principle function of the RPM capacity market is to set prices for capacity consistent with the value the capacity provides to the system. Locally-focused procurement outside of the capacity market increases the potential for significant deviations between the reliability contribution a resource provides to the system and the revenue it receives. Under a large-scale FRR, there would no longer be robust capacity price signals to guide capacity additions and retirements.

More broadly, a substantial weakening or elimination of the PJM capacity market would undermine reliability and require significant alteration of the PJM construct. As described in greater detail in the appendix to this paper, generation capacity represents the capability to produce electric power, and in order to operate reliably the electric system needs physical capacity in sufficient quantity to deliver energy across the full range of potential system conditions—e.g., during extreme hot or cold weather events—while also providing excess capability to account for power plants being out of service at times due to scheduled maintenance or unexpected outage. The energy and ancillary services markets in PJM are designed to dispatch and compensate generating resources based on their marginal operating costs—i.e., the cost of producing energy or ancillary services in the moment—excluding longer-term fixed costs. This creates economic efficiency in producing power from the existing set of generating resources, but does not provide sufficient revenue to cover full plant costs, particularly for generators that typically operate on the margin. The energy and ancillary services markets provide such marginal plants revenue to cover short-run operating costs, but with little or no contribution to fixed costs. Generators that operate primarily on the margin, or only during extreme system conditions, will earn insufficient revenue in the short-run markets to cover their costs, though they may provide very valuable (or essential) support for maintaining reliable electric service.

The PJM capacity market serves a dual purpose in establishing the minimum quantity of capacity needed for reliable system operation and setting the price for capacity based on generator offers and the current supply/demand balance. Prices in the capacity market are low, but not zero, when there is excess capacity, but as conditions get tight and additional capacity is needed to meet anticipated demand, prices rise to the "cost of new entry" (CONE), or rather the net CONE, which is the additional revenue, on top of what can be expected from the energy and ancillary markets, needed to support investment in new generating capacity.

When there is excess supply, as there is now in PJM (the market is expected to have a surplus of approximately 14,000 MW as of June 2020),[37] the essential place of the capacity market in the PJM construct may be less evident, but it is important to appreciate that the excess capacity exists in large part because of the capacity market and the expectation of its continued operation. If the capacity market were to cease operating effectively, or entirely, such that capacity revenue were substantially reduced or eliminated, generators that currently provide valuable services to the system would be forced to retire in the absence of some replacement mechanism to compensate capacity. Ultimately, the revenue necessary to retain needed capacity and induce investment in additional capacity would have to be made up elsewhere—the immediately available alternative being the energy and ancillary services markets. But to provide revenue to cover fixed as well as operating costs, PJM would need to be altered substantially to function as an "energy only" market in which energy prices are allowed to rise far above cost during periods of relative supply scarcity. The Electric Reliability Council of Texas (ERCOT) administers such an energy-only market—with no capacity market—that allows energy prices to rise as high as \$9,000/MWh. In 2019, the average ERCOT real time hub price reached \$9,000 in one hour, and was greater than \$1,000/MWh a total of 26 hours. The maximum real-time price at PJM's Western Hub in 2019 was \$746/MWh in a single hour, and only nine hours had prices exceeding \$300/MWh.

The essential point is that the PJM capacity market is currently integrated within a consistent market construct designed to compensate resources for the value they provide to the system, including the contribution capacity makes to system reliability. There is no free lunch available from dispensing with

[37] 2019 SOM, page 258.

the capacity market. Substantial changes to the efficacy of the capacity market, or its elimination, will necessarily entail modifications to the market that will revenue sufficiency to keep needed resources from retiring and inducing new investment when needed.

IV. Healthy Wholesale Markets Can Facilitate State Policy

Centralized wholesale markets are mechanisms that harness competition to increase the efficiency and reliability of meeting electricity needs now and in the future. They enable suppliers to provide needed services to customers at the lowest cost and risk to ratepayers and taxpayers. Moreover, healthy wholesale markets support state policies by providing market revenue and prices signaling the value of resources to the electric system.

Wholesale markets provide a structure to value, compensate and incentivize resources with particular needed attributes, such as fast-ramp capability to accommodate sudden variations in wind output, and inverter-based technologies that can provide voltage support and other ancillary services at the margin. For example, MISO has introduced several market modifications, including an additional ramp capability product and an improved offer-based mechanism for renewable resources, that enhances the ability of the system to use intermittent resources cost-effectively while maintaining system reliability.

To the extent that increased quantities of generation supplying energy at near-zero cost are affecting the economic viability of other traditional generating resources, wholesale markets provide mechanisms to compensate resources needed for system reliability—either through the capacity market, or through markets for other needed services.

IV.A. **Cost-Effective Mechanisms for Promoting Emissions Reductions**

State policy goals for reducing CO2 emissions are justified on a number of grounds. While this paper is not concerned with the rationale for pursuing such policies, the means employed to achieve emissions reductions, and in particular the cost-effectiveness of alternative approaches are relevant to the issues considered here. From an economic perspective, narrowly-targeted direct subsidies such as those provided under various ZEC programs to existing, high-cost power plants or that are contemplated through an FRR with preferential procurement and pricing, are not a cost-effective way to reduce CO2 emissions. Mechanisms that promote competition to achieve a policy result, and which are neutral with respect to technology, ownership and other pre-determined preferences, including location, generally produce results at lower cost. This is partly a function of competition on cost, where bidders increase the likelihood of being selected to provide a solution by reducing costs, which reduces the offers they can submit. Additional, and potentially greater, benefits can be achieved through mechanisms that are technology neutral, because the most innovative solutions are difficult to anticipate. Picking winners as part of policy design tends to leave a lot of potentially fruitful ground unexplored.

Inefficiencies can also arise from methods intended to promote multiple, unrelated policy objectives. For example, it appears that a significant factor in the development of the New York ZEC programs was the retention of upstate nuclear power plants that supported employment and the local tax base in an economically challenged region. Both CO2 emissions reduction and local economic development are legitimate policy objectives, but a blunt policy tool intended to address both limits the solutions that are advanced to address each, and obscures the true cost of advancing distinct goals.

Economists view a carbon tax or cap-and-trade program as the most efficient means to reduce carbon emissions, because they are market-based, technology-neutral, and in principle can be applied across all emitting sectors, not just power generation. Such broad, market-based approaches provide maximum scope for entities to pursue low-hanging fruit—i.e., the easiest, least-costly emissions reductions first—and to explore and invest in innovative technologies and strategies.

RGGI is a functioning, successful cap-and-trade emissions market with state membership spanning three RTOs: Delaware, Maryland and New Jersey (PJM); Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont (ISO New England); and New York (New York ISO). The current scope and cap levels under RGGI mean that it is not a one-tool solution to achieving substantial carbon emissions reductions. One indicator of this is that recent RGGI clearing prices for vintage 2020 allowances have only been around $6.00 per ton of CO2. This would translate to an increased cost of generation from a coal-fired power plant of around $6.00/MWh, using a rough value for coal plant emissions of about a ton per MWh. While this is not an insignificant effect, a $6.00 per ton CO2 price is far below estimates of the social cost of carbon, which are generally above $40 per ton and rising over time.[38]

RGGI is not intended to create an effective price of carbon emissions at the social cost of carbon, but is intended to work in concert with other state policies to promote emissions reductions. And it is an effective component of the policy toolkit. In October, 2019, the governor of Pennsylvania signed an executive order requiring the state Department of Environmental Protection to draft a regulation to make Pennsylvania a member of RGGI. In response to this action, the owner of the Beaver Valley nuclear power plant in Shippingport, PA, announced in March 2020 that the plant would not be retired at the end of 2021 as previously announced.[39] In April 2020, Virginia adopted legislation under which the state will join RGGI in 2021.[40]

Another policy tool employed by many states to reduce CO2 emissions (among other goals) is to establish RPSs mandating that electricity demand in the state be supplied in specified quantities or proportions from certain energy sources, typically new wind and solar. RPS programs may require competitive procurement, and generally allow compliance to be demonstrated through RECs that can be traded freely, and often from out-of-state sources. Such flexible programs, levering competition and trading of RECs, are qualitatively different from narrow, direct subsidy programs such as ZECs. Among the distinguishing features of RPS/RECs that contrast with ZECs are the following:

- RPS/RECs are targeted at incentivizing investment in new generation, particularly from nascent renewable energy technologies, to accelerate cost reductions as technologies mature. They are not aimed at keeping uneconomic legacy resources from retiring.
- Eligibility for RPS/RECs is based on resource specifications, not the economic need of the plant or owner.

[38] In a 2013 technical document, the US Government's Interagency Working Group on Social Cost of Carbon established values for the social cost of carbon for application in regulatory impact analysis. The value for 2020, applying a 3.0% social discount rate, corresponds to approximately $40 per ton in 2020 dollars.

[39] https://stateimpact.npr.org/pennsylvania/2020/03/13/owners-of-pa-s-beaver-valley-nuclear-power-station-will-keep-it-open-because-of-states-climate-plan/

[40] https://www.virginiamercury.com/2020/04/14/virginia-lawmakers-agreed-to-join-a-regional-carbon-market-heres-what-happens-next/

- RPS/RECs prices are based on a competitive procurement process, and RECs are openly traded.
- With RPS/RECs, investors/developers continue to bear cost, operational and market risks (e.g., winning a competitive procurement with a low offer does not guarantee that costs and profit will be recovered).

RPS programs have been enormously successful, as demonstrated by the substantial growth of renewable generation over the past decade as well as the substantial decline in costs of wind and solar generation. Large-scale wind and solar are already economically viable without subsidies in some parts of the country (i.e., particularly windy and sunny areas), and are increasingly economically competitive with traditional resources in all regions. Competitive wholesale power markets, including capacity markets, facilitate the transition of renewable resources away from mandatory RPS programs and implicit or explicit subsidies under state policies.

Finally, additional natural gas-fired generation may also be a cost-effective means to reduce CO2 emissions, because of persistent low natural gas prices; but only to the extent that higher-emitting resources are allowed to retire when they become uneconomic. Even the most efficient gas-fired generators emit CO2, but at much lower rates than older fossil-fuel power plants, particular those burning coal. It is by quickly displacing higher-cost, higher-emitting resources that gas-fired plants can provide cost-effective emissions reductions.

IV.B. **Subsidizing Costly Legacy Generation Impedes Clean Energy Goals**

Subsidies, or alternatives such as an FRR, aimed at keeping costly, uncompetitive legacy generators in operation ultimately work against clean energy objectives because they increase costs and/or discourage investments in new, low- or zero-emitting generation. Money that subsidizes old, high-cost power plants that would otherwise retire for economic reasons represents ratepayer (or taxpayer) funds that could have been deployed directly through competitive markets to support cost-effective resources that promote policy goals. Subsidizing uneconomic legacy generation undermines market incentives for more efficient, lower emitting facilities to enter or stay in the market. The subsidized plants displace more economic—and more valuable resources.

Subsidies that keep high-cost plants from retiring, facilitate both the ability of these resources to continue to participate in the centralized wholesale markets for energy and ancillary services, as well as capacity, and also to offer into those markets at below cost, which reduces the market prices that other generators, such as wind, solar and batteries can receive. Those new technologies have achieved increased scale and reduced costs—trends which are continuing—and they are increasingly cost-competitive in their own right, exclusive of subsidies. Robust, undistorted competitive power markets reduce the reliance of these new resources on direct and indirect policy support, decreasing the costs to consumers. In contrast, market distortions caused by subsidies to high-cost legacy generators reduce the ability of new clean technologies to rely on market revenues, and increase the out-of-market cost of supporting those technologies. Over the long term, this frustrates states' clean energy objectives, and makes them more difficult and costly to achieve.

Appendix A. Centralized Wholesale Electricity Markets

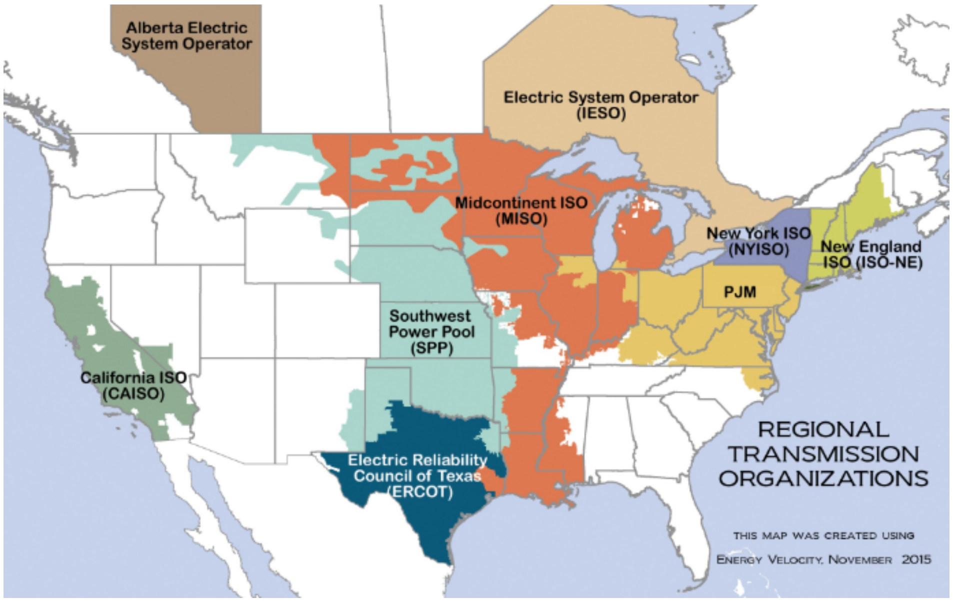
For most of the 20th century in the United States, the production and delivery of electricity centered on so-called "vertically integrated" utilities that built, owned and operated generation, transmission and distribution assets as local monopoly franchises. Each utility was allowed by its state or local regulator to fully recover from ratepayers all prudently-incurred costs of producing and delivering electric power, including a regulated return on investment. Beginning in the late 1970s, the federal government advanced a variety of rules to allow for competition in the generation of electricity, and to ensure access to the transmission grid for non-utility generators to sell power at wholesale. In Order Nos. 888 and 889 (1996), the Federal Energy Regulatory Commission (FERC) required public utilities to establish tariffs to allow third parties to access their transmission systems, with the goal to remove impediments to wholesale competition, and ultimately to encourage more efficient, lower cost generation of electricity.

In the late 1990s and early 2000s, various US states restructured the regulation of electric utilities to explicitly remove the generation of electricity from the business of public utilities. Most of the states in the northeast, Ohio, Michigan, Illinois, Texas and California substantially restructured their respective electric utilities by the early 2000s, dramatically expanding the wholesale market for power.

FERC further promoted the development of regional power markets through its Order No. 2000 (1999), which encouraged states (and their transmission-owning utilities) to join an independent system operator (ISO) or regional transmission organization (RTO). RTO/ISOs are independent, nonprofit organizations that operate the power system, typically over a multi-state region, administer centralized wholesale markets for power, and oversee the reliability and planning of the transmission system. Two-thirds of electricity use in the United States is by consumers in an RTO/ISO.[41]

[41] "The Value of Independent Regional Grid Operators," The ISO/RTO Council. Available at: http://www.nyiso.com/public/webdocs/media_room/press_releases/2005/isortowhitepaper_final11112005.pdf.

Figure 5: Regional Transmission Organizations in North America[42]



RTO/ISOs administer spot markets for energy and so-called "ancillary services" to determine the efficient generation of electricity from available resources minute-by-minute (in "real-time" markets) and in anticipation of the next operating day (in "day-ahead" markets). The clearing prices in these markets are determined by competitive offers, with lowest-cost resources being selected first, subject to certain constraints necessary to maintain the reliability of the system. These clearing prices also serve a longer-term function in signaling where additional investment in supply, transmission and energy efficiency are economic.

Certain RTO/ISOs—PJM, MISO, NYISO and ISO-NE—also have separate centralized markets for capacity. Capacity represents the *capability* of a resource to produce electric power when called upon. The generation of energy must be balanced minute by minute to demand, and is compensated based on the quantities actually produced, and ultimately consumed. Capacity may or may not be actively used to produce energy at a given moment, but it provides value to the system to the extent that it may be needed. The level of electricity demand varies substantially based on daily usage patterns, changes in weather, seasons, and economic conditions. The system's annual peak need may be spread over a small number of

[42] https://www.ferc.gov/industries-data/electric/power-sales-and-markets/rtos-and-isos.

hours, or even a single hour, meaning that some generation capacity is needed to produce energy only a small portion of the time, yet is nonetheless necessary for keeping the lights on. In addition, generators need to be out of service periodically for maintenance, and unexpected outages of individual generators or parts of the transmission system occur regularly, which means that the system actually needs capacity greater than the anticipated peak demand in order to operate reliably.

This excess capacity need—referred to as the capacity reserve margin—is a challenge in a competitive market context, because the actual production of electricity compensated at hourly clearing prices may leave some generators with insufficient revenue to cover their costs.

Centralized markets for capacity provide a mechanism, supplementary to the energy and ancillary services markets, to compensate resources for essential contributions to the electric system.

Resource Revenue from Centralized Markets

Centralized wholesale markets, such as those administered by PJM and other RTO/ISOs, establish energy prices for each point in time, typically every five minutes, and at different locations (PJM has more than 10,000 locational pricing nodes). The clearing price in energy markets is based on the cost of generating the last quantity of electricity needed to meet demand in the moment (and location), with generating resources selected by the system operator to generate in order from lower to higher cost, subject to constraints to maintain reliability. The energy market is intended to secure generation to meet load efficiently (only using higher cost resources when necessary), and to create incentives for generators to minimize operating costs and increase plant availability. Energy markets set prices per unit of actual generation, generally expressed in dollars per megawatt hour ($/MWh).

The single-price nature of energy markets means that sources of energy with very low operating costs, such as wind turbines and nuclear power plants, receive energy market revenue in excess of their immediate operating costs in most hours. The excess of the energy price over the cost of generation is a plant's net energy revenue.

The economic viability of a generator that sells into the wholesale markets depends on its total costs relative to the combined revenue it can receive in the energy, ancillary services and capacity markets. Plant costs include not only current generating costs, but also the ongoing fixed costs that are required to keep the plant ready to operate when needed, and which may be avoidable only through plant retirement. Some power plants, like nuclear generators, have a low cost of generating energy, but high fixed costs. Other types of plants, such as simple cycle turbines burning natural gas or oil, have relatively high costs of generation, but low fixed costs. In both cases, competitive plants earn revenue to cover their costs in the same markets, but may earn a greater or smaller share of their revenues from the energy and ancillary services markets relative to the capacity market.

The following assessment of net revenue data focuses on the PJM markets.

PJM Energy and Capacity Markets

PJM operates competitive wholesale electricity markets and manages the reliability of its transmission grid.[43] In managing the grid, PJM centrally dispatches generation and coordinates the movement of wholesale electricity in all or part of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia) and the District of Columbia. PJM's markets provide for the pricing and procurement of energy (day-ahead and real-time), capacity (Reliability Pricing Model or RPM), and ancillary services, including regulation, synchronized reserves, and day-ahead scheduling reserve.

As of 2019, PJM had installed generating capacity of approximately 200,000 MW, serving a region of more than 65 million people.[44]

Energy Market

The PJM energy market procures electricity to meet consumers' demands both in real-time (five minutes) and on a day-ahead (one-day forward) basis. PJM uses locational marginal prices (LMPs) to price energy

---

43 PJM was founded in 1927 as a power pool of three utilities serving customers in Pennsylvania and New Jersey. In 1956, with the addition of two Maryland utilities, it became the Pennsylvania-New Jersey-Maryland Interconnection, or PJM. PJM became a fully functioning ISO in 1996 and, in 1997, it introduced markets with bid-based pricing and locational market pricing. PJM was designated an RTO in 2001.

44 Measures of generation capacity distinguish between 'installed' quantities, which represent maximum generation capability, and other measures that capture performance characteristics of resource types and historical performance of individual resources. Capacity quantities referenced in this paper are installed quantities unless otherwise noted.

purchases and sales. LMPs are derived using a physical flow-based pricing methodology that includes local generation costs, transmission congestion, and the cost of transmission losses to move energy within the PJM service territory. Accordingly, LMPs represent the marginal cost to serve the next MW of demand at a specific location, using the lowest production cost of all available generation, while observing all transmission constraints and operating limitations. To ensure the lowest production cost, PJM requires that generators bid the price and amount of generation at generator-specific locations (i.e., a generator "bus") and accepts bids from the lowest until the accepted amount meets the demand. The resulting market clearing price is the LMP and is paid to all accepted bidders in that specific location without regard to the original bid price. LMPs are calculated both in day-ahead and real-time auctions.

Unlike other generators that rapidly change their output in response to fluctuating demand, nuclear generators are inflexible and generally run continuously at maximum output. Since the opportunity costs of not running a nuclear plant are exceptionally high, they generally bid as price-takers in the energy markets to ensure that they can continuously sell their energy, regardless of the clearing prices in the day-ahead and real-time energy market auctions. At times of high energy prices, nuclear plant owners earn very large margins, since fuel costs are far cheaper than for fossil fuel plants. However, the recent decline in natural gas prices, driven primarily by the abundance of cheap shale gas, has decreased energy prices, thereby dramatically reducing the profitability of many nuclear plants, as well as other generation owners. Nonetheless, current low energy prices are the result of the operation of competitive markets, as the PJM IMM has found.

Capacity Market

The PJM capacity market, called the Reliability Pricing Model (RPM), was first introduced in 2007. The RPM ensures long-term grid reliability by procuring an appropriate amount of capacity resources needed to meet forecasted energy demand three years in the future. By matching energy supply with future energy demand, the RPM creates long-term price signals to attract needed investments in generation infrastructure and to assure adequate power supplies in the region. In the PJM capacity market, a load-serving entity (LSE) is required to have the resources to meet its customers' demand plus a reserve. LSEs can meet that requirement in four ways: (i) with generating capacity they own; (ii) with capacity they purchase from others under contract; (iii) through demand response, in which end-use customers reduce their usage in exchange for payment; or (iv) with capacity obtained through the RPM auctions.[45]

LSEs in PJM procure capacity three years before it is needed through a competitive auction administered by PJM that results in locational pricing for capacity that varies to reflect limitations on the transmission system and accounts for the differing needs for capacity in various areas of PJM.

Similar to the energy market, the RPM participants offer power supply resources into the market that either increase energy supply or reduce demand at a certain price and volume at specific locations, called Locational Delivery Areas (LDAs).[46] The PJM capacity market accepts the offer from the lowest bid price until the requisite amount for each capacity zone has been met. The last accepted offer in each capacity zone establishes the market-clearing price for that zone, and all accepted capacity resources in that zone are paid the respective market-clearing price regardless of the original offer price. Accepted capacity resources must deliver energy or reduce demand in the energy market, if warranted, especially during power system emergencies. Otherwise, they are subject to significant penalty payments.

Net Revenue Results in PJM

PJM's independent market monitor (IMM) regularly evaluates and reports on estimated net revenue from PJM's wholesale markets for different resource types, and also assesses revenue adequacy—the extent to which resources can cover avoidable costs via the centralized markets. If resources cannot consistently achieve revenue sufficient to cover avoidable costs, it is expected that they would exit the market, either through retirement and deactivation, or potentially by becoming capacity resources in a neighboring ISO/RTO and selling into those markets.

---

45 The RPM conducts a series of auctions for a delivery year in the future. The majority of capacity is procured in the first auction for a particular delivery year, which is known as the Base Residual Auction (BRA). This auction is conducted three years in advance of a given delivery year. The RPM model works in conjunction with PJM's Regional Transmission Expansion Planning (RTEP) process to ensure the reliability of the PJM region for future years.

46 LDAs are established by their ability to move electricity in the event of an emergency. LDAs are determined annually through PJM's RTEP process. There are currently 27 LDAs in PJM.

The evaluation of net revenue and revenue adequacy in the centralized markets provides valuable information about effects from ongoing changes to the resource mix and energy usage patterns, and also about the functioning of the markets themselves.

PJM wholesale markets are designed as a consistent set of mechanisms for incentivizing the provision of cost-effective resources to meet system needs, and the capacity market is an integral part of the package.

In 2018, the energy markets did not provide net revenue for most units to cover their avoidable costs. The capacity market provided additional revenues sufficient to make up the shortfall for most units on the system, with the exception of some coal and nuclear units.

Nuclear Revenue Sufficiency

Based on estimated unit costs, the PJM markets provided sufficient revenue in 2018 to cover the costs of nuclear units across the footprint, providing surplus revenue to 16 of 19 plants. One of the three units with estimated revenue shortfalls was Oyster Creek, which retired in September 2018. Another, Three Mile Island, retired in September 2019. Davis Besse in Ohio was the third.

A forward-looking analysis through 2021 indicated that two operational nuclear plants would fail to recover avoidable costs—Davis Besse and Perry—both single-unit facilities located in Ohio. Davis Besse was expected to retire in 2020, and Perry in 2021. However, in 2019 Ohio enacted legislation to provide subsidies intended to keep the plants in operation until 2027.

PJM Generator Retirements

Table 3: Generator Retirements in PJM, MW of Installed Capacity[47]

	Coal	Nuclear	Other	Total
2010	893	0	173	**1,066**
2011	581	0	853	**1,434**
2012	5,015	0	614	**5,629**
2013	3,072	0	186	**3,258**
2014	2,131	0	978	**3,109**
2015	8,015	0	2,232	**10,247**
2016	386	0	193	**580**
2017	1,942	0	755	**2,697**
2018	2,891	550	908	**4,349**
2019	2,160	981	4,245	**7,386**
Totals	**27,086**	**1,531**	**11,137**	**39,754**

It is important to emphasize that the retirement of uneconomic generation assets is not a bad thing, and in fact is an important indicator that supplying power competitively is acting as intended. Generators that cannot cover their costs in the wholesale market generally exit the market and do not impose their excess costs on ratepayers. Retirements of coal-fired generation and nuclear plants is an indicator of the value of the wholesale markets to end-use customers, not an indicator of market failure. Rather than ratepayers being required to continue to pay for uneconomic assets under cost-of-service regulation, it is the asset owners that bear that cost and are encouraged to retire assets that no longer provide sufficient value to the system to warrant their cost.

[47] Totals based on data from Form EIA-860m (see footnote 6).

PJM Generator Additions

The PJM markets have supported substantial capacity additions over the same period.

Table 4: Generator Additions in PJM, MW of Installed Capacity[48]

	Natural Gas	Wind	Solar	Other	Total
2010	209	976	51	74	**1,310**
2011	1,223	888	225	945	**3,281**
2012	1,916	1,271	191	745	**4,122**
2013	89	8	131	342	**570**
2014	2,252	240	166	40	**2,698**
2015	2,756	213	364	156	**3,488**
2016	3,279	787	557	236	**4,859**
2017	3,510	568	549	13	**4,640**
2018	12,162	326	522	65	**13,075**
2019	1,447	397	246	21	**2,112**
Totals	**28,843**	**5,673**	**3,004**	**2,636**	**40,156**

The PJM wholesale markets have been effective at inducing both orderly economic exit, and investment in new generation capacity. Indeed, these are closely related patterns. The fall in natural gas prices driven by the shale gas boom (itself a function of competitive markets) has made gas-fired generators more cost effective, and kept energy clearing prices low. Large, baseload generation units, such as coal-fired and nuclear plants, with high fixed costs have typically relied on a large amount of net energy market revenue to be viable. Lower energy prices have reduced the ability of such plants—particularly older coal-fired generators—to cover their avoidable costs.

The capacity market has consistently cleared at prices below the net cost of new entry (net CONE). This reflects the fact that the PJM market has maintained more than sufficient capacity to ensure system reliability. The design of the capacity market provides for compensation to generators consistent with the

48 Totals based on data from Form EIA-860m (see footnote 6).

reliability value they provide to the system, but does not reach the full cost of new entry until excess supply decreases to near the minimum requirement.