OLSON, BZDOK & HOWARD

March 12, 2021

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

Via E-filing

RE: MPSC Case No. U-20804

Dear Ms. Felice:

The following is attached for paperless electronic filing:

PUBLIC Testimony of Devi Glick on behalf of Sierra Club

Exhibits SC-1 through SC-16 (with SC-9 and SC-14 being Confidential)

Proof of Service

Sincerely,

Digitally signed by Christopher M. Bzdok
DN: cn=Christopher M. Bzdok, o=Olson Bzdok & Howard, P.C., ou, email=chris@envlaw.com, c=US
Date: 2021.03.12 16:16:18 -05'00'

Christopher M. Bzdok
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xc: Parties to Case No. U-20804

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of INDIANA MICHIGAN POWER COMPANY for approval of a Power Supply Cost Recovery Plan and Factors (2021)	)))))	**Case No. U-20804**

PUBLIC

Direct Testimony of Devi Glick

On Behalf of Sierra Club

March 12, 2021

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PUBLIC TESTIMONY OF DEVI GLICK
U-20804

1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Associate at Synapse Energy Economics, Inc. My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, utility resource planning practices, valuation of distributed energy resources, and utility handling of coal combustion residuals waste. I have submitted expert testimony on unit commitment practices, plant economics, utility resource needs, and solar valuation before state utility regulators in Michigan, Arizona, Connecticut, Florida, Indiana, New Mexico, North Carolina, South Carolina, Texas, Virginia, and Wisconsin. In the course of my work, I develop in-house electricity system models and perform analysis using industry-standard electricity system models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than eight years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit SC-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the Michigan Public Service Commission ("Commission")?

A Yes, I submitted testimony in Case No. 20224, the 2019 Indiana Michigan Power Company's ("I&M" or "Company") power supply and cost recovery reconciliation docket.

Q What is the purpose of your testimony in this proceeding?

A In my testimony for this proceeding, I review and evaluate the prudence of I&M's power supply cost recovery ("PSCR") plan for 2021. Specifically, I evaluate I&M's justifications for charging Michigan customers for the purchase of energy from its affiliate, Ohio Valley Electric Corporation ("OVEC") under the Inter-Company Power Agreement ("ICPA"), at above-market prices and review I&M's oversight of OVEC's operational and planning decisions. I also evaluate the Company's operation of the Rockport units, and review fuel and power purchase costs it plans to pass on to customers, during the PSCR plan and five-year forecast period.

Q How is your testimony structured?

A In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I discuss how I&M customers are paying unreasonable prices to OVEC for power under the ICPA. I provide background on the ICPA and I&M decision in 2010 to extend the contract through 2040. I discuss the complete insufficiency of any analysis performed by I&M to justify the ICPA contract in 2010 and the lack of data provided in prior and current dockets to justify the decision. I explain why market prices are a reasonable metric against which to value the ICPA. I compare the costs of the ICPA to market prices for the same services and show that I&M is proposing to charge customers above market prices for the energy and capacity it purchases from OVEC. I review OVEC's uneconomic operational practices that are driving the significant losses seen at the units on both a marginal cost and a total unit cost basis. Based on I&M's and OVEC's own forecast data, I calculate the projected costs that will be passed on to I&M ratepayers in the near term (2021–2025) and long term (2021–2040). I discuss how I&M has been imprudently managing the ICPA by remaining ignorant of OVEC's operational and planning decisions. I summarize details of the affiliate relationship between I&M and OVEC. I also outline my recommendations to the Commission to disallow inclusion of ICPA costs above market value in its maximum PSCR factor and to caution I&M that the Commission may not allow recovery of costs above market value in future reconciliation dockets.

In Section 4, I discuss how I&M is imprudently operating the Rockport units and passing the excess costs on to its ratepayers, both directly through fuel costs and through power purchased from AEP Generation ("AEG"). I provide background on the ownership and operation of the two Rockport units. I discuss the Company's pattern of uneconomic operation of the units, and the resulting costs that are incurred for I&M ratepayers. I calculate the costs that I&M is projected to incur at the Rockport plants on a forward-going basis. I recommend that the Commission caution I&M that it may disallow recovery of future excess costs from Rockport 2 if I&M renews its lease (or enters into any type of power purchase agreement) with the current or any future owners of Rockport 2 without contemporaneous Commission approval.

Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the workpapers, exhibits, and discovery responses of I&M witnesses associated with this proceeding. I also rely on public information associated with prior I&M proceedings. To a limited extent, I also rely on certain external, publicly available documents such as State of the Market reports for PJM.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. I&M has been purchasing power from OVEC under the ICPA at above market value and passing those costs on to customers since 2017. Over the course of 2020, the ICPA has cost I&M customers $26.5 million more than the cost of equivalent energy and capacity purchased from the market.

2. OVEC currently operates its two power plants, Clifty Creek and Kyger Creek, uneconomically and incurs net losses relative to market energy prices. In 2020, I&M ratepayers incurred $2.5 million in losses relative to the energy market on just a variable cost basis. In 2020, I&M customers would have been better off if the OVEC plants had not operated at all. These losses could be mitigated with more prudent unit commitment practices.

3. I&M is projected to lose [[[redacted]]] in energy market revenue and capacity value over the PSCR forecast period of 2021–2025 and [[[redacted]]] over the life of the ICPA (on a present value basis) by purchasing

energy from OVEC under the ICPA. These costs will be passed on to ratepayers, absent protection from the Commission.

4. I&M is subject to the MPSC Code of Conduct and, as such, is required to cap payment to an affiliate based on market prices and rates. The Company's sustained pattern of paying OVEC above-market prices for power appears to violate the Code of Conduct.

5. I&M has been imprudently managing its ICPA contract with OVEC. It has taken no apparent steps to minimize costs and losses and has remained ignorant of the operational and planning decisions being made at the plant, including the forward-going economics of the decision to keep the plant online and the 2020 decision to invest in Coal Combustion Residuals ("CCR") and Effluent Limitation Guidelines ("ELG") upgrades.

6. I&M has operated, and continues to operate, the two Rockport units uneconomically. I&M incurred net losses relative to market energy prices of $25.1 million in 2020 on a variable cost basis. These losses could have been mitigated with more prudent unit commitment practices.

7. I&M's latest fuel cost plan and five-year forecast indicate that I&M intends to continue its uneconomic operation and commitment practices at the Rockport units. The Company plans to pass on the costs incurred through both (1) generation fuel costs (for the portion I&M owns and leases), and (2) power purchased from AEG (for the portion it purchases under PPA), which combined, exceed market revenues by [[[redacted]]] million per year over the next five years.

Q **Please summarize your recommendations.**

A Based on my findings, I offer the following chief recommendations:

1. The Commission should amend the PSCR plan by removing the costs of the OVEC ICPA from the maximum PSCR factor for the plan year. The Commission should reduce I&M's forecast costs by the difference between OVEC's expected costs and the expected cost of market purchases for energy and capacity during that time period.

2. The Commission should issue a Section 7 warning to I&M that on the basis of present evidence it will likely disallow I&M's recovery of the Michigan jurisdictional share of compensation for the ICPA in 2021–2025.

3. To the extent that I&M continues paying costs under the ICPA, recovery of all purchased power costs from OVEC should be capped at the equivalent price that I&M would pay to procure the energy, capacity, and ancillary services from the PJM market in each given year.

4. The Commission should not approve I&M's PSCR plan to the extent it is developed around the assumption that it will continue to uneconomically self-commit the Rockport units, and put I&M on notice that the Commission may disallow recovery of the costs of such operation.

5. The Commission should caution I&M that if the Company extends its lease or enters into a new purchase agreement with current or future Rockport unit 2 owners to continue to lease or purchase power from Rockport unit 2 without contemporaneous Commission approval of that lease or purchase agreement decision, the Commission may disallow recovery of all or part of those costs in future proceedings.

6. The Commission should indicate that it will disallow recovery in future fuel cost reconciliation dockets of the fuel portion of all net revenue losses incurred as a result of imprudent unit commitment decisions.

3. I&M CUSTOMERS ARE PAYING UNREASONABLE PRICES TO OVEC FOR POWER UNDER THE ICPA.

i. I&M purchases power from OVEC under the ICPA.

Q What is OVEC and how is it related to I&M ratepayers?

A OVEC is an entity jointly owned by 12 utilities in Ohio, Indiana, Michigan, Kentucky, West Virginia, and Virginia. OVEC operates two 1950s-era coal-fired power plants— (1) Kyger Creek, a five-unit, 1,086 MW plant in Gallia County, Ohio, and (2) Clifty Creek, a six-unit, 1,303 MW plant, in Jefferson County, Indiana. The Company supplies the power from these plants to the utilities through a long-term contract called the Inter-Company Power Agreement (ICPA).[1] Together, the utilities are responsible for the fixed and variable costs of OVEC. In turn, OVEC bills the utilities a variable, demand, and transmission charge.

Q What portion of OVEC is I&M responsible for?

A I&M's share of the ICPA with OVEC is 7.85 percent.[2] This means that I&M is responsible for 7.85 percent of OVEC's fixed and variable costs while also being entitled to a 7.85 percent share of OVEC's power output. This translates into an installed capacity ("ICAP") share of 174–174.3 MW. The cost of the ICPA is passed through to I&M ratepayers as a direct cost. In 2020, I&M was billed $47,665,070 by OVEC for 721,476 MWh.[3]

Q Has I&M ever sought or received approval from the Commission for its decision to sign the ICPA?

A No. Before 2004, the ICPA was set to expire on December 31, 2005. Before this date, the Sponsors agreed among themselves to extend the ICPA to 2026.[4] I&M did not seek approval from the Michigan PSC for the decision to enter into the contract around the time that decision was made in 2004.

In September 2010, the Sponsors again agreed to a revised ICPA that extended its term until 2040. I&M and the other participating investor-owned utilities are therefore obligated to cover the costs of the OVEC plants through 2040. The Clifty Creek and Kyger Creek Plants will each be 85 years old by the time the ICPA expires.[5] Once again, I&M did not request or receive Commission approval for its decision to enter into a revised ICPA contemporaneous with its decision to sign that

[1] Ex SC-2 Ohio Valley Electric Corporation, Annual Report – 2019 (p. 1).
[2] *Id.*
[3] Ex SC-3 I&M Response to SC 4.01, SC 1-14 Attachment 1.
[4] Ohio Valley Electric Corporation, Annual Report – 2019 (p. 1).
[5] *Id*.

contract in 2010. Other utilities, including I&M's affiliate, Appalachian Power, did seek approval for the decision to sign the 2010 contract from the relevant state commission.[6]

ii. <u>I&M pays above-market prices for the power it purchases from OVEC and passes the excess costs on to its customers.</u>

Q How does I&M serve customer load, and which associated costs are at issue in this PSCR docket?

A I&M serves customer load broadly through three types of resource: (1) generation assets owned (or leased) and operated by the Company, (2) power purchased under PPAs from generation assets owned by other entities or affiliates, and (3) PJM market power purchases.

For units owned or leased by I&M, the fuel costs associated with running the units are forecasted in this PSCR docket and recovered directly through fuel adjustment clauses. All other operational costs are the subject of separate proceedings (rate cases and riders). For power purchased under PPAs or directly from the market, the entire cost to operate the units that the power comes from, not just the fuel costs, is forecasted in this PSCR docket and recovered directly from customers through fuel adjustment clauses.

Q What does it mean that I&M is paying OVEC above-market prices for power?

If I&M can purchase the energy, capacity, or ancillary services that it needs from the PJM market at a lower cost than it would pay to purchase power from OVEC under the ICPA, then it is paying above the market price for the OVEC power.

[6] In re Application of Appalachian Power Company, Docket No. PUE-2011-00058, Virginia State Corporation Commission, Order Granting Approval, August 3, 2011.

Q Considering only variable charges and energy market revenue, is the ICPA delivering net revenues to I&M ratepayer?

A No. I compared the total energy charges billed to Sponsoring Companies under the ICPA and the revenue that I&M earned selling that energy into the PJM energy market. I&M's own data shows that in 2020 OVEC billed I&M $18,487,826 in energy charges for 721,476 MWh of electricity.[7] That works out to an energy cost of $25.63/MWh. But I&M only earned $15,960,650 in energy and ancillary market revenue selling that energy, which works out to a value of $22.12/MWh. That means that on a marginal cost basis alone, in 2020 I&M lost $2.5 million for its ratepayers (excluding demand charge and capacity value).

Q Is the ICPA delivering value to I&M ratepayers based on the total value of its provided services?

A No. I compared the total cost billed to members of the ICPA by adding demand and transmission charges to the energy charges I already reviewed. I compared this cost to the value of the energy, capacity, and ancillary services provided by OVEC if I&M sold those services into the PJM. I&M's own data shows that in 2020 OVEC billed I&M a total of $47,665,070 for the 721,476 MWh of electricity.[8] That works out to $66.07/MWh, up from $55.59/MWh in 2019[9].

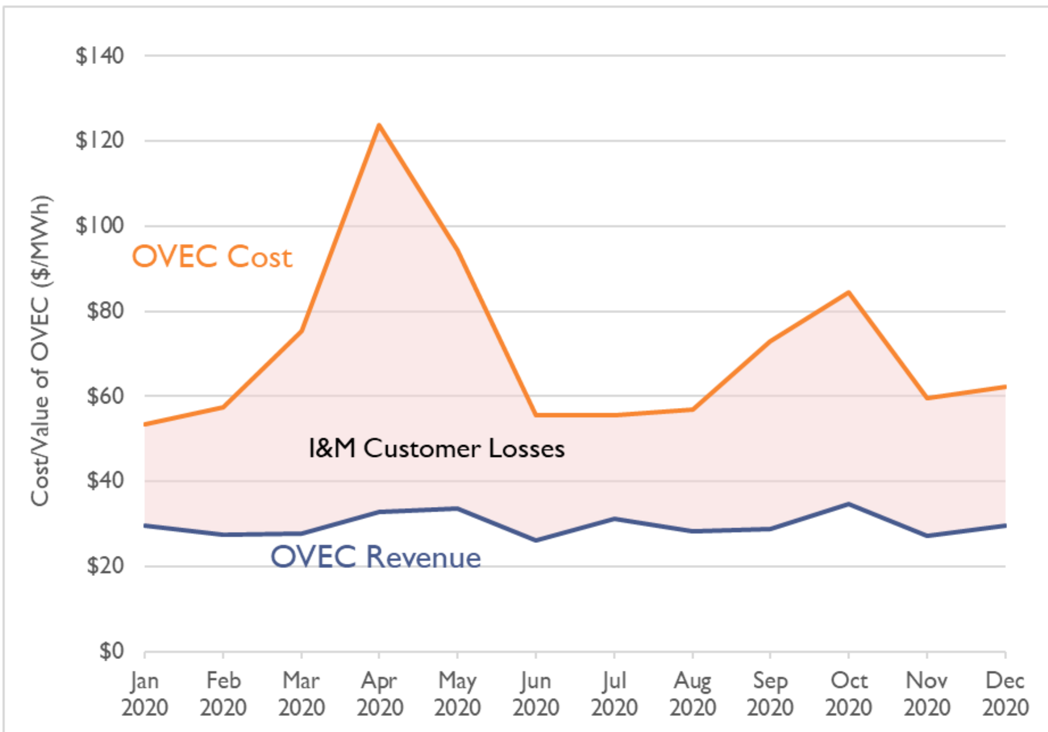
In contrast, the value of the market revenue that would be generated in PJM for OVEC's energy, capacity, and ancillary services was equivalent to only $29.38/MWh for I&M.[10] This is well below the cost OVEC is charging I&M and

[7] I&M Response to Sierra Club Discovery Request 1-14, SC 1-14 Attachment_1.
[8] *Id*.
[9] *Id.*
[10] I&M Response to Sierra Club Request 4-01, SC 4-01 Attachment 1, Exhibit SC-3; Ex SC-4 I&M Response to Sierra Club Request 4-01, SC 4-01 Attachment 2; and Ex SC-5a State of the Market Report for PJM, January through September (2020).

is much closer to the average cost of power I&M purchased from PJM in 2019 at $31.83/MWh.[11]

That amounts to a net loss of $26.5 million in 2020 that I&M customers are being asked to pay while receiving no additional value. In Figure 1 below, I show the all-in monthly cost of OVEC's services relative to the value the services are providing to I&M ratepayers. In each month of 2020, I&M ratepayers were paying significantly more for OVEC services than the equivalent market value of the services.

Figure 1: All-in OVEC cost / value for energy, ancillary services, and capacity (2020)



Source: I&M Response to Sierra Club Request 4-01, SC 4-01 Attachment 1; I&M Response to Sierra Club Request 4-01, SC 4-01 Attachment 2; and Ex SC-5a State of the Market Report for PJM, January through September (2020).

[11] Exhibit IM-3(DHL-1), (p.3), Case No, U-20224.

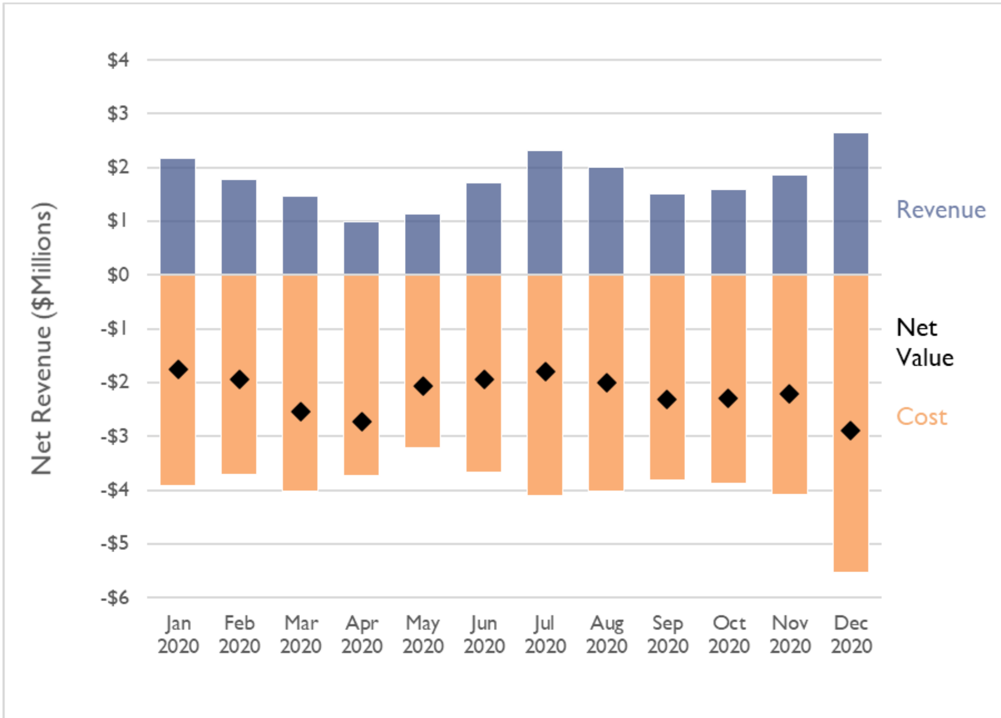
Q How do you calculate the cost to ratepayers of OVEC's contract?

A I&M provided the monthly billing from OVEC for 2020 which includes MWh sold, energy, demand, and transmission charges, along with PJM expenses and fees.[12] The Company provided energy and ancillary revenue by month.[13] The Company refused to provide the ICAP associated with its share of OVEC by month so I relied on the values provided for 2021 (174 MW in January–May, and 174.3 MW June–December).[14] I estimated a capacity value based on the value that I&M's share of OVEC capacity would receive in the PJM Base Residual Auction.

To find the net value or cost to ratepayers of the ICPA, I assumed the cost of the OVEC contract was equivalent to the monthly billing from OVEC. I assumed the value of the ICPA would be equal to the sum of the energy, ancillary services, and capacity value, with the later calculated as if OVEC's capacity were sold under PJM's Base Residual Auction ("BRA"). Figure 2 below shows the monthly OVEC billing versus I&M revenue from ICPA energy, ancillary services, and capacity for 2020. In every month, I&M customers were billed substantially more for OVEC power than I&M would have received from the PJM market for OVEC's services.

[12] Ex SC-3, I&M Response to Sierra Club Request 4-01, SC 4-01 Attachment 1.
[13] Ex SC-4, I&M Response to Sierra Club Request 4-01, SC 4-01 Attachment 2.
[14] Ex SC-6, I&M Response to Sierra Club Request 4.7.

Figure 2: OVEC billing versus I&M revenue from ICPA energy, ancillary services, and capacity (2020)



Source: I&M Response to Sierra Club Request 4-01, SC 4-01 Attachment 1; I&M Response to Sierra Club Request 4-01, SC 4-01 Attachment 2; and Ex SC-5a State of the Market Report for PJM, January through September (2020).

Q How does the cost and value of the ICPA in 2020 compare to the cost and value of the power in recent years?

A The cost for power under the ICPA has been significantly above market value since at least 2017 (the last year for which the Company provided complete data). As shown in Table 1 below, this is not a new occurrence or a single year fluke, it is in fact part of a pattern of poor and steadily worsening performance.

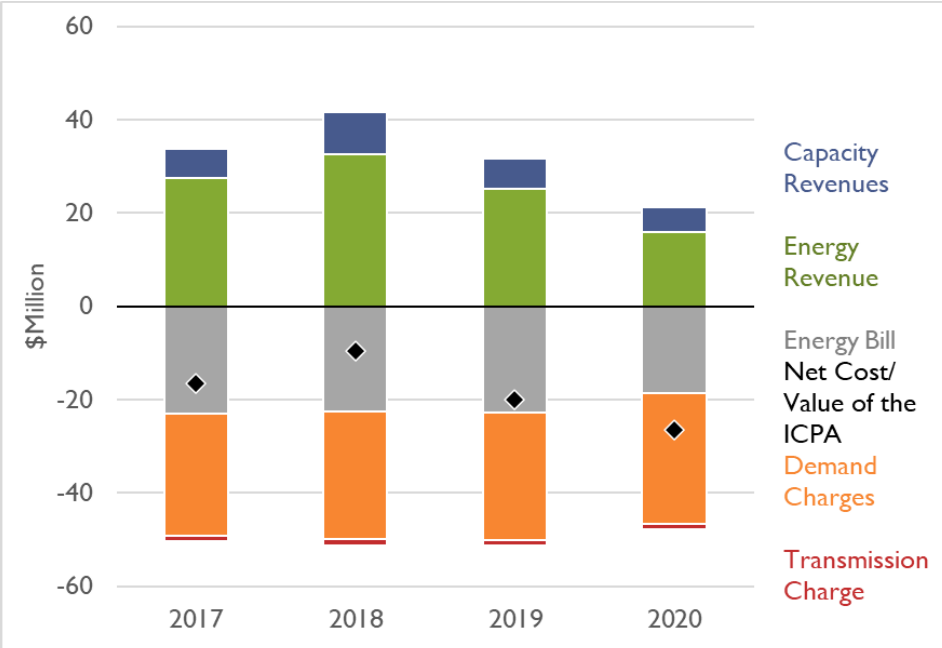
Table 1: OVEC Power costs billed to I&M and market value (2015–2020)

	MWh Electricity	**Total OVEC Charges billed to I&M**	**Total Market Value**	**$/MWh cost**	**$/MWh value**	**Net cost/value**
2015	648,744	$42,945,374	Data not provided	$66.20	Data not provided	Data not provided
2016	743,577	$44,287,508		$59.56		
2017	937,620	$50,371,649	$33,803,653	$53.72	$36.05	($16,567,996)
2018	958,430	$51,213,687	$41,586,273	$53.43	$43.39	($9,627,413)
2019	926,846	$51,524,987	$31,663,991	$55.59	$34.16	($19,860,996)
2020	721,476	$47,665,070	$21,312,856	$66.07	$29.54	($26,352,214)

Source: I&M Response to Sierra Club Request 4-01, SC 4-01 Attachment 1; I&M Response to Sierra Club Request 4-01, SC 4-01 Attachment 2; Ex SC-5b, State of the Market Report for PJM, January through September (2018).

As shown in Figure 3, market revenue for power purchased under the ICPA has declined significantly every year since 2018, but costs have declined only marginally. This is due in large part to the demand charge component of the ICPA, which locks ratepayers into high fixed costs regardless of the quantity of energy purchased or whether I&M even needs the energy or services provided.

Figure 3: OVEC charge and revenue by component (2017–2020)



Source: I&M Response to Sierra Club Request 4-01, SC 4-01 Attachment 1; I&M Response to Sierra Club Request 4-01, SC 4-01 Attachment 2; and State of the Market Report for PJM, January through September (2020); State of the Market Report for PJM, 2018.

Q What do you conclude with respect to the ICPA and the services that I&M ratepayers receive from the contract?

A Based on I&M's own data I find that under the ICPA, I&M customers have been paying more than market equivalent for services since at least 2017. In 2020 alone, the energy charges under the ICPA cost I&M customers $2.5 million more than the market value of energy, while the total billed charges (inclusive of energy, capacity, transmission, and other charges) cost I&M customers $26.5 million more than the market price for the same amount of energy and capacity. This means that even with the demand-charge locked in, ratepayers would have been better off if the plant had not operated in 2020 and I&M instead purchased energy from the market. Further, as my analysis in later sections will show, the ICPA is projected to continue to be higher cost than market-equivalent product and services, and therefore will continue to be costly for I&M ratepayers.

iii. <u>A reasonable price to pay for power under the ICPA should be measured based on the market equivalent value of the services provided.</u>

Q What was the estimated cost of the ICPA to I&M at the time I&M decided to sign the 2010 OVEC contract?

A An AEP Service Corporation ("AEPSC") "benchmark study", conducted on behalf of OVEC, found that the ICPA was expected to have a cost of $7.51 billion on a present value basis between the years 2011 and 2040.[15] This means I&M's share of the contract was expected to cost $589.4 million on a present value basis in 2011.[16]

Q Did the benchmark study conducted in 2011 determine that it was reasonable to extend the ICPA for 30 years?

A No. The 2011 "benchmark study," which appears to have been conducted and submitted to the Federal Energy Regulatory Committee ("FERC") *after* I&M agreed to an extension of the ICPA, was a mere seven-page document that compared the cost of OVEC to the levelized cost of new fossil fuel resources. The analysis did not consist of robust forward-looking analysis or consider what I&M's system actually needs, or what the lowest-cost way to meet those needs would be. Additionally, the Company failed to disclose critical assumptions used by the modelers that were essential to evaluating the reasonableness of the analysis. Also, fundamentally, it is impossible that an analysis conducted after a decision was made could have in fact informed the reasonableness of the decision.

While such an analysis may be acceptable for rough screening purposes, it was in no way sufficient for justifying a decision as consequential as extending a power

[15] Ex SC-7 Benchmark Study. April 27, 2011.
[16] *Id.*

contract three decades and locking I&M ratepayers into hundreds of millions of dollars in unit costs.

Q What type of study or analysis should I&M had conducted contemporaneously with its application to extend the contract?

A To evaluate the reasonableness of such a decision, I&M and AEP should have engaged in an optimized resource-planning exercise. As part of this exercise, they should have evaluated system needs, estimated the forward-going cost to operate the unit under the ICPA, estimated the likely costs of alternatives, and evaluated risk and uncertainty from, among other things, fuel prices volatility and CO_2 prices. This type of exercise is typically performed by utilities and requested by state utility commissions, whenever significant resource planning decisions are made by utilities.

Q What are appropriate comparators for a long-term PPA?

A The current value of a contract can be assessed based on available alternatives, including, in this instance, PJM market prices for energy and capacity. The PJM market represents the price that other actors are willing to pay for energy, capacity and ancillary services to meet their system needs. I&M of course can purchase incremental energy requirements from the PJM energy market. The PJM capacity price represents a proxy for the price of incremental capacity if I&M sought to procure capacity.

An even more conservative measure of value, if I&M were capacity constrained, as it projects it will be starting in 2023,[17] would be to value the capacity portion of the ICPA at PJM's Cost of New Entry ("CONE). This represents the cost of building

[17] Exhibit IM-7.

new gas-fired generation capacity and could be used to value capacity in just the years with a capacity constraint.

Q Why is it reasonable overall to use the PJM capacity market to value the capacity of a Fixed Resource Requirement ("FRR") entity such as I&M?

A If I&M or any other PJM FRR entity wanted to acquire capacity, they would look to the PJM capacity market as a benchmark. The PJM capacity market represents the price that buyers are willing to pay for capacity in the region. The PJM capacity auctions provide generally the same service as the demand charge portion of the ICPA, which covers the non-variable costs incurred to maintain the OVEC plants (capital improvements, operations and maintenance, and other non-variable costs).

[[[redacted]]].[19] In addition, I&M used PJM's forecasted capacity market prices as a fundamental parameter of its 2018–2019 Integrated Resource Plan, and the Company priced short-term market purchase of capacity based on PJM capacity pricing.[20]

[18] I&M Response to Sierra Club Request 4.08, SC 4.08 CONFIDENTIAL Attachment 2.
[19] I&M Response to Sierra Club Request 1-05, SC 1-05a CONFIDENTIAL Attachment 1.
[20] "I&M 2018-2019 Integrated Resource Plan," *Indiana & Michigan Power*, 1 July 2019 (p. 102).

iv. <u>OVEC operates its two power plants, Clifty Creek and Kyger Creek, uneconomically and incurred $29.5 million in net losses relative to market energy in 2020 alone.</u>

Q How often did OVEC operate its plants in 2020?

A OVEC operated the Clifty Creek and Kyger Creek plants at 51 percent and 66 percent capacity factors respectively during 2020 despite both units incurring substantial revenue losses relative to the market. In fact, at least one unit at each plant was online and generating during every hour of 2020.[21] This shows that OVEC is not taking action to limit incurring negative energy margins at its plants, and instead is operating them even when it would cost Sponsoring Companies less to not operate any units.

Q Did OVEC's plants cover their variable operating costs with energy market revenues in 2020?

A No. During 2020, OVEC's variable costs exceeded market locational marginal prices ("LMPs") in 83 percent of the hours the units operated. This incurred a total of $29.5 million in variable operating losses across the two plants, $2.3 million of which is allocated to I&M customers.[22] Coal plants such as Clifty Creek and Kyger Creek require high capital costs to stay online, and therefore need large positive energy margins to cover these costs. When a plant losses money on a variable basis, that means it is not covering its fuel and operational and maintenance costs, and therefore it is also contributing nothing to cover these significant fixed and capital costs. In 2020, I&M customers would have been better off if the OVEC plants had not operated at all.

[21] EIA FACT Tool, Clean Air Markets Data for Clifty Creek and Kyger Creek; PJM LMPs for OVEC Zone accessed at https://dataminer2.pjm.com/feed/da_hrl_lmps.
[22] *Id.*

Q How did you calculate these variable losses?

A OVEC includes the cost of coal, allowances, and other fuel-related costs in its energy charge,[23] so I used the energy charge as a proxy for the OVEC unit's variable costs. I obtained hourly LMPs for the OVEC units in 2020 from PJM, hourly gross generation from the EPA Clean Air Markets Data set, and monthly net generation from U.S. Energy Information Administration ("EIA") Form 923.[24] I calculated hourly energy market revenue by combining hourly net generation and market LMPs. For each hour in 2020, I compared the monthly billed energy costs cost to hourly energy market revenue to find the hourly net margin that resulted from operating the unit.

Q How did the OVEC units incur significant losses if they were operating within the PJM market?

A Generators operating within the PJM market generally commit[25] their available units as either economic or must-run. For units committed economically, the market operator, PJM, has the responsibility for unit commitment and dispatch decisions. Those decisions prioritize reliability for the system as a whole, but then select plants to commit and dispatch based on short-term economics to ensure customers are served by the lowest-cost resources available to the system. A plant committed as "economic" will operate only if it is the least-cost option available to the market (i.e., has a lower variable cost than other resources available at the time).

[23] I&M Response to Sierra Club Request 2-17, SC 2-17 Attachment 1.

[24] EIA Form 923, accessible at https://www.eia.gov/electricity/data/eia923/.

[25] In my testimony, I will use the term "unit commitment" to refer to the decision made by the utility or the market on whether to operate a unit at its minimum operating level and therefore make it available to the market. I will use the term "unit dispatch" to refer to the decision by the utility or the market on how to operate a unit above its minimum operating level once the unit has been committed online.

While economic commitment and dispatch tends to be the norm for dispatchable power plants, for units with long startup and shutdown times, such as OVEC's coal-fired power plants, utilities often instead elect to maintain control of unit commitment decisions and utilize a "must-run" commitment status. For these units, the utility determines independently, and often without regard for economics, when to commit a unit. A unit designated as must-run will operate with a power output no less than its minimum operating level.[26] The unit receives market revenue (and incurs variable operational costs) but does not set the market price of energy. If the market price of energy falls below its operational cost, a must-run unit will not turn off and can incur losses that a utility often seeks to recover from ratepayers.

Because units operated by the market follow short-term economic signals, they tend to cycle off when market prices are low and therefore do not generally incur significant operational losses. The OVEC units, on the other hand, stayed online the majority of 2020 despite incurring significant net revenue losses. This indicates that the units were very likely self-committing as "must run" and that OVEC operated the plants without regard to I&M's customers' interests.

Q What drives a power plant operator such as OVEC to uneconomically self-commit its units?

A There are many factors that drive a power plant operator to uneconomically self-commit their units, but four main ones are: (1) a failure to evaluate the economics of daily unit commitment decisions; (2) failure to follow the results of daily unit commitment analysis; (3) incomplete accounting of variable unit costs in unit

[26] Minimum operating level is an output threshold often determined operationally, and below which a generator is either less stable or operates inefficiently. Once the unit commitment decision is made, the level of generation output (above the minimum) is generally left to the market. The operating level is based upon the marginal running cost assumptions provided by the owner in the form of offers or bids to PJM.

dispatch bids; and (4) minimum take provisions in fuel contracts that "lock in" costs that would otherwise be variable.

I&M asserted repeatedly in response to discovery questions about the OVEC units that it does not have "operational responsibility"[27] for OVEC and that it does not have or control requested information about the units' operation,[28] therefore I have no clear information on OVECs unit commitment and operational decision or decision-making processes. What is clear is that OVEC made decisions that increased I&M's customers' costs in 2020.

v. I&M is projected to pass on to ratepayers [[[redacted]]] million in losses relative to the OVEC units energy market revenue and capacity value over the next five years by purchasing power under the ICPA.

Q In the past two years, has I&M conducted any analysis on the forward-going value of the ICPA to its ratepayers?

A No. I&M has conducted no analysis, nor is the Company aware of any other analysis that has been conducted during the past two years, on the economics of operating the OVEC units.[29] I find this troubling for power plants like these that are deeply uneconomic.

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[27] Ex SC-8, I&M Response to Sierra Club Request 1-12; I&M Response to Sierra Club Request 1-13; I&M Response to Sierra Club Request 1-21; I&M Response to Sierra Club Request 2-6; I&M Response to Sierra Club Request 2-7.
[28] *Id.*
[29] I&M Response to Sierra Club 1-10.

Q And what did you find when you conducted your own forward-going analysis of the ICPA using I&M's and OVEC's own data?

A I found that over the short term (2021–2025) the OVEC units are likely to cost I&M ratepayers [[[redacted]]] million in present value terms more than the market value of services, or an average of [[[redacted]]] million per year above market value (as shown in [[[redacted]]] below). Over the remaining life of the ICPA (2021–2040), I&M ratepayers are expected to pay [[[redacted]]] million in present value terms more than the market value of equivalent services, or an average of [[[redacted]]] million per year above market value.[30] These values, which rely on I&M's and OVEC's own projections, are directionally aligned with the findings of the other public analyses discussed below.

[[[redacted]]]

Source: I&M Response to Sierra Club Request 4-08, CONFIDENTIAL Attachment 1; I&M Response to Sierra Club Request 4-08, SC 4-08 CONFIDENTIAL Attachment 2;

[30] Ex SC-9C, I&M Response to Sierra Club Request 4-08, SC 4-08 CONFIDENTIAL Attachment 1; I&M Response to Sierra Club Request 4-08, SC 4-08 CONFIDENTIAL Attachment 2; I&M Response to Sierra Club Request 1-26, SC 1-26 1H2019 Base Attachment 3.

I&M Response to Sierra Club Request 4-07, SC 4-07 Attachment 1; I&M Response to Sierra Club Request 1-26, SC 1-26 1H2019 Base Attachment 3.

Q Explain how you calculated the forward-going value of the ICPA by using the Company's and OVEC's own data.

A I&M provided a monthly projection for the years 2021-2025 of OVEC's estimated power sales (MWh), and billable costs under the ICPA, broken down by energy charges and demand charges.[31] The Company also provided AEP's fundamental forecast prepared by AEPSC in 2019, which includes projections for energy market prices. Using the estimated MWh sales from the OVEC bill and the energy price projections from the fundamental forecast, I calculated the value of the energy provided by OVEC. The Company also provided capacity values[32] and ICAP values[33] for 2021 – 2025, which I combined to get total capacity revenue. I summed the energy and capacity values and compared the value of the power to the costs OVEC estimates it will bill to find the net value or losses associated with the ICPA. I assumed that the OVEC units dispatched on-peak 56.7% of the time, which is the average on-peak generation percentage of Clifty Creek and Kyger Creek in 2019 and 2020 according to public data obtained from the EPA Clean Air Markets Division (CAMD).[34] For years beyond 2024, I assumed generation levels, energy and demand charges all remain constant at 2024 levels.

[31] I&M Response to Sierra Club Request 4-08, SC 4-08 CONFIDENTIAL Attachment 1.

[32] Ex SC-9C I&M Response to Sierra Club Request 4-08, SC 4-08 CONFIDENTIAL Attachment 2.

[33] Ex SC-6, I&M Response to Sierra Club Request 4-07, SC 4-07 Attachment 1.

[34] Environmental Protection Agency, "Air Markets Program Data," accessed 8 March 2021. Accessible at: https://ampd.epa.gov/ampd/

Q What does the capacity value have to be for the OVEC units to appear economic on a forward-going basis?

A In order for the ICPA to be economical on a forward-going basis, that is, for the value of *all* products and services provided by OVEC to I&M to equal the cost of the ICPA, the capacity portion of OVEC's services would have to be valued at an average of [[[redacted]]] over the PSCR forecast period (2021–2025) and [[[redacted]]] over the remaining life of the contract (2021–2040). That means capacity prices have to not only go that high but be sustained at that level. This is substantially higher than the PJM CONE values calculated by Brattle in 2018 of $289/MW-Day for a new Combined Cycle Unit and $259/MW-Day for a new Combustion Turbine Unit (both in $2022),[35] which is generally used to represent the ceiling for capacity price assumptions. It is absolutely not reasonable or prudent to plan around the assumption that capacity prices at this level will ever materialize, let alone be sustained over a period of time.

Q When were the most recent forward-going analysis on the economics of operating the OVEC units conducted?

A There were several analyses performed between 2015 and 2019. The findings of all these analyses are aligned with the findings of my own forward-looking analysis of the ICPA. These include the following:

1. In March 2017, Duke Energy Ohio hired ICF Consulting to conduct forward-looking analysis of the ICPA that projected substantial net losses associated with holding position in the ICPA. Their analysis, scaled to

[35] Ex SC-10, PJM Cost of New Entry, Combustion Turbines and Combined Cycle Plans with June 1, 2022 Online Date. The Brattle Group. April 2018.

I&M's share, suggest losses of $67 million relative to market alternatives between 2020 and 2025.[36]

2. In April 2019, FirstEnergy Solutions, another OVEC Sponsoring Company, had a similar forward-looking analysis conducted through 2040 and found projected losses, scaled to I&M's share, of $267 million relative to market alternatives.[37]

3. In December 2018, Moody's Analytics conducted an assessment of the ICPA in late 2018, and scaled to I&M's share, found annual losses of $16-$20 million.[38]

4. In 2015 and 2016, I&M's AEP affiliate AEPSC performed a forward-looking analysis of the ICPA. The results of this analysis, called the "OVEC Merchant Analysis," are confidential, but they were presented to OVECs board.[39] [[[redacted]]][40]

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[36] Ex SC-11 Revised Public Version of Supplemental Testimony of Mr. Judah L. Rose on behalf of Duke Energy Ohio, Inc. (July 10, 2018, at 20, Exhibit 2, Ohio PUC Docket 17-0872-EL-RDR, accessible at http://dis.puc.state.oh.us/CasesByYearIndustry.aspx.

[37] Ex SC-12 Expert declaration of Judah Rose (Doc. 46, filed Apr. 1, 2018), In re FirstEnergy Solutions Corp., No. 18-50757 (AMK) (Bankr. N.D. Ohio).

[38] Ex SC-13 Moody's Investors Service. December 2018. Credit Opinion: Ohio Valley Electric Cooperative.

[39] Ex SC-14 I&M Response to Sierra Club Request 2-15, SC 2-15 CONFIDENTIAL Attachment 1; I&M Response to Sierra Club Request 2-15, SC 2-15 CONFIDENTIAL Attachment 2.

[40] *Id.*

Q What do you conclude based on the results of your own analysis, and the findings of the other forward-looking analysis completed on the value of the ICPA?

A I&M has neglected to evaluate the forward-going economics of continuing to purchase power under the ICPA over the past few years. But this analysis establishes that if I&M is allowed to continue to purchase power from OVEC under the ICPA, I&M ratepayers will be forced to pay hundreds of millions of dollars more than the market value of the power over the next two decades. These findings, which were conducted using the Company's own data, were confirmed by the analysis conducted by several other reputable consulting firms over the past few years.

vi. I&M has been imprudently managing its ICPA contract with OVEC by remaining ignorant of the operational and planning decision made at the plant.

Q What is I&M's role in operating, and managing the OVEC plants?

A I&M is a Sponsoring Company of OVEC and as such I&M and its AEP affiliates are allowed to appoint one member among them to OVEC's Operating Committee. According to the Amended and Restated Inter-Company Power Agreement (September 10, 2010), the Operating Committee has a role in unit operations:

> *The "Operating Committee" shall establish (and modify as necessary) scheduling, operating, testing and maintenance procedures of the Corporation in support of this Agreement, including establishing: (i) procedures for scheduling delivery of Available Energy under Section 4.03…*[41]

[41] I&M Response to Sierra Club Request 2-03, SC 2-03 Attachment 1.

But, as discussed above, I&M asserted repeatedly in discovery that it does not have "operational responsibility"[42] for OVEC and that it does not have control over or access to information that is critical or understanding the cost to operate OVEC, including the Company's fuel contracts, and forward-going fixed and operating costs.[43] These claims appear to be at odds with the role and responsibilities that the ICPA intends for Sponsoring Companies to have.

Q What are standard industry practices undertake by regulated utilities to ensure its PPAs reflect reasonable and prudent prices for customers?

A Putting aside for a moment the Code of Conduct and I&M's failure to seek approval of its decision to enter into the ICPA, prudent utility management practices dictate a utility would do the following going forward in managing a contract such as the ICPA:

1. Exercise oversight and have knowledge of the operational and planning decisions that impact the costs passed on to its ratepayers.
2. Evaluate and undertake measures to reduce operational costs at the units that are operating at a loss relative to alternatives or the market.
3. Attempt to renegotiate the terms of the contract to minimize losses to its ratepayers.
4. Regularly evaluate the forward-looking economics of the plants to determine whether it is in the best interest of its ratepayers to continue to invest new capital in and operate a plant relative to retirement. Such analysis

[42] *See*, I&M Response to Sierra Club Request 1-12; I&M Response to Sierra Club Request 1-13; I&M Response to Sierra Club Request 1-21; I&M Response to Sierra Club Request 2-6; I&M Response to Sierra Club Request 2-7.

[43] *See*, I&M Response to Sierra Club Request 1-17; I&M Response to Sierra Club Request 1-18. I&M Response to Sierra Club Request 2-7.

is especially important before moving forward with major investments, such as those needed for ELG and CCR compliance

Q How does I&M manage the ICPA with OVEC in reality?

A I find that I&M imprudently manages the ICPA with OVEC. As discussed above, I&M claims it has no role in the operation of OVECs units and has taken no steps to address the uneconomic commitment practices that are driving the high variable costs at OVEC's units. Additionally, there is no evidence that I&M has attempted to renegotiate terms of the ICPA.

Finally, I&M and OVEC have performed no analysis on the economics of continuing to operate the OVEC plants relative to retirement and replacement with alternative resources recently. Most notably, I&M has not evaluated the economics of investing in ELG and CCR compliance technologies relative to retiring the plants or some of their 11 units.[44] Here again, I&M seeks to absolve itself from that responsibility, claiming that OVEC and not I&M that controls the decision on whether to move forward with the environmental upgrades.[45]

Q What do you conclude regarding I&M's management of the ICPA with OVEC?

A Although I&M has the authority under the ICPA to exercise control over at least some of the operational decisions at OVEC that are increasing energy costs for I&M customers, the Company has declined to invoke that authority. Instead, I&M has passed these costs on to its customers without any documented effort to reduce costs through exercise of its ownership stake in OVEC (either by requiring that OVEC produce analysis on the reasonableness of the costs, conducting analysis

[44] I&M Response to Sierra Club Request 1-22.
[45] I&M Response to Sierra Club Request 2-04.

itself, or producing the information necessary for the Commission to perform a review of the prudence of the forward going ICPA costs).

vii. I&M is subject to the MPSC Code of Conduct, and as such is required to cap payments to affiliates, such as OVEC, based on market prices and rates.

Q Explain the nature of the relationship between I&M and OVEC.

A While I&M has a 7.85 percent stake in OVEC, I&M's parent company, AEP, represents the single largest participation interest in OVEC. Three AEP Companies, Appalachian Power Company (15.69 percent), I&M (7.85 percent), and Ohio Power Company (19.93 percent), are together the largest participation block in the ICPA at 43.47 percent. In addition, AEP itself has a 43.47 percent equity stake in OVEC.[46]

The relationship between AEP and OVEC goes beyond this joint-ownership structure. AEP leadership serves on the board of OVEC, and AEP staff members provide a range of operational services to both OVEC and OVEC's wholly owned subsidiary, the Indiana Kentucky Electric Corporation ("IKEC").

The leadership links between AEP/I&M and OVEC include:[47]

- Paul Chodak III, AEP's Executive Vice President of Generation, and prior President of I&M, currently serves as the President of OVEC and IKEC.
- I&M has direct input into the ongoing operations and finances of OVEC and the OVEC units. Toby Thomas, President and Chief Operating Officer of I&M, serves on the Board of Directors for IKEC. David Lucas, Vice President of

[46] Ohio Valley Electric Corporation, Annual Report – 2019 (p. 1).

[47] AEP Leadership Biography of Paul Chodak III, available online at: https://www.aep.com/about/leadership/chodak; Ohio Valley Electric Corporation, Annual Report – 2019 (p. 4); "Credit Opinion: Ohio Valley Electric Cooperative," *Moody's Investors Service,* December 2018.

Finance and Corporate Experience and witness in I&M's 2019 rate case, also serves on the Board of Directors for IKEC.

- AEP holds two other director's seats at OVEC: Raja Sundararajan, President and Chief Operating Officer of AEP Ohio; and Lana Hillebrand, Senior Vice President and Chief Accounting Officer of AEP.

Beyond overlapping leadership, AEP maintains significant operational ties to OVEC. These ties impact the administration of the ICPA and include:[48]

- OVEC holds a long-standing service agreement with AEPSC under which AEP administers and negotiates the terms of existing and proposed fuel contracts for OVEC.
- OVEC's Board Meetings have been hosted at AEP headquarters in Columbus, Ohio, and have regularly featured AEP staff to report on economics, environmental compliance, and fuel procurement—in other words, many fundamental aspects of running two coal plants.
- When OVEC filed for acceptance of the 2010 contract decision, as noted above, it asked AEP to conduct the benchmark study to provide to FERC to support that contract decision that had already been made.
- Because AEP is the largest owner of OVEC equity, AEP has an incentive to keep the plants operating regardless of the economics of continuing to operate the units. If the plants were to retire, AEP shareholders might be on the hook for outstanding debt at the time of retirement.

I&M's parent company, AEP, plays an active role in the oversight, management, and operations of OVEC, and a number of AEP executives hold leadership positions in OVEC.

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[48] Ex SC-15 I&M Response to MPSC Case No. U-20529 SC 1-20; and OVEC Board Meeting Notes from 01 December 2015 and 08 December 2017, MPSC Case No. U-20529.

Q Does the relationship between I&M's parent company, AEP, and OVEC warrant any additional review in Michigan?

A Yes. I am informed by counsel that the MPSC Code of Conduct makes OVEC an "affiliate" of I&M. The Code of Conduct disallows utilities from acquiring from affiliates "products or services" in excess of the "market price." [49] As I demonstrated above, AEP and I&M pay well above market price for OVEC's products and services.

Taking the Code of Conduct's definitions of "affiliate" and "control," it appears that OVEC is an affiliate of I&M by virtue of being "under common control."[50] AEP is both a parent company to I&M and the single-largest participating interest in OVEC. In total, AEP has a 43.47 percent equity stake and participation interest in OVEC via subsidiary holdings—far above the 7 percent ownership level that the Code of Conduct defines as "control."[51] And as I've discussed, AEP maintains close ties with OVEC through director seats, the AEPSC/OVEC service agreement, and the placement of AEP executives within OVEC.

Most importantly for this preceding, the Code of Conduct requires that affiliate product and services which are not defined "value-added" programs under Michigan Compiled Law ("MCL") 460.10ee(8) be capped at the cost of market product and services. As discussed above, OVEC has been billing, is billing, and will bill I&M substantially above market prices, which suggests that the transaction does not comply with the Code of Conduct.

viii. <u>The Commission should not allow I&M to develop its PSCR plan assuming purchases under the ICPA at above market costs, and the Commission</u>

[49] MPSC Code of Conduct, R460.10102 and R R460.10108.
[50] *Id.*
[51] Ohio Valley Electric Corporation, Annual Report – 2019 (p. 1).

should cap I&M's recovery of the Michigan jurisdictional share of compensation for the ICPA in future dockets.

Q What do you recommend regarding I&M's forecasting of future costs incurred under the ICPA in its PSCR plan?

A The Commission should not allow I&M to create its PSCR plan around the assumption that it will continue to purchase power under the ICPA at above-market prices. I&M should instead only be allowed to include in the PSCR plan costs incurred under the ICPA up to the equivalent market value of the power, as determined by the value of energy, ancillary services, and market prices for capacity.

Q What do you recommend to the Commission regarding I&M's recovery of ICPA contract costs above market prices in future reconciliation dockets?

A The Commission should issue a Section 7 warning to I&M that on the basis of present evidence it will likely disallow I&M's recovery of the Michigan jurisdictional share of compensation for the ICPA in 2021–2025.

4. I&M IS IMPRUDENTLY OPERATING THE ROCKPORT UNITS AT EXCESS COSTS TO ITS RATEPAYERS.

i. I&M is responsible for 85 percent of the cost to operate Rockport Units 1 and 2.

Q Provide an overview of the Rockport Generating Station.

A The Rockport Generating Station is a two-unit coal-fired power station located in Spencer County, Indiana. Unit 1 has a nameplate capacity of 1,320 MW and Unit 2 is 1,300 MW. Unit 1 is owned 50 percent by I&M and 50 percent owned by AEG. Unit 2 is owned by non-affiliated parties and is leased back to I&M and AEG at a 50 percent share each. AEG sells 70 percent of its share of each Rockport unit back to I&M and 30 percent to Kentucky Power's ("KPCo") under a Unit Power sales agreement.[52]

I&M's and AEG's leases of Unit 2 expire in December 2022, and both entities have indicated they do not plan to renew their respective leases at that time.[53] I&M does plan to purchase the capacity from Unit 2 through May 2023 to align with PJM's capacity market.[54] KPCo purchase from AEG also expires in December 2022, at which time I&M is expected to take the power from Unit 1 that was previously committed to KPCo.[55]

Q What portion of Rockport's costs is I&M responsible for and how are those costs passed on to its ratepayers?

A I&M is responsible for the costs associated with the 50 percent share of Rockport 1 that it owns and the 50 percent share of Rockport 2 that it leases. The associated fuel costs are planned for in this PSCR docket and passed on directly to customers as fuel costs through fuel clauses. The remaining unit costs are passed on to ratepayer through rate case and other dockets.

I&M also is responsible for the costs associated with the 70 percent share of AEG's portion of Rockport it purchases through a Unit Power Sale agreement. But because this power is procured through a power purchase agreement, instead of from a unit operated by I&M, the entire cost of this share is passed on directly to customers through fuel clauses (not just the fuel costs). That means the entire PPA cost is forecasted and planned for in this PSCR docket.

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[52] Direct Testimony of Baker, pages 7-8.
[53] I&M Response to Sierra Club Request 3-1b, Attachment SC 3-1b.
[54] Direct Testimony of Baker, page 8 lines 8-12.
[55] I&M Response to Sierra Club Request 1-1d.

In total, I&M is responsible 85 percent of the costs associated with Rockport units 1 and 2.

ii. <u>I&M has been operating, and continues to operate, the two Rockport units uneconomically, and incurred approximately $25.1 million in net losses relative to market energy on just a variable basis in 2020.</u>

A The Rockport units operated at only a 17.5 percent capacity factor in 2020.[56]

Q Did the Rockport plants cover their variable operating costs with energy market revenues in 2020?

A No. In 2020, the Rockport units' variable costs exceeded market LMPs in 86 percent of the hours the units were online (both units were offline for 40 percent of the hours in 2020). The Rockport units incurred a total of $30.9 million in variable operating losses across the two plants during the hours the units were online, $26.2 million of which is allocated to I&M customers.[57]

Q How did you calculate these variable losses?

A I obtained hourly LMPs for the Rockport units in 2020 from PJM, hourly gross generation from the EPA Clean Air Markets Data set, and monthly net generation from the EIA Form 923. I calculated hourly energy market revenue by combining hourly net generation and market LMPs. I used the energy charges billed by AEG as a proxy for variable costs.[58] For each hour in 2020, I compared the monthly variable cost to hourly energy market revenue to find the hourly net margin that resulted from operating the unit.

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[56] EIA Form 923, accessible at https://www.eia.gov/electricity/data/eia923/.

[57] EIA FACT Tool, Clean Air Markets Data for Rockport Units 1 and 2; PJM LMPs Rockport accessed at https://dataminer2.pjm.com/feed/da_hrl_lmps.

[58] Ex SC-16, I&M Response to Sierra Club Request 4-10, SC 4-10 Attachment 1.

Q What other evidence do you have that the Rockport units are a bad deal for I&M's ratepayers?

A As discussed above, AEG owns 50 percent of Rockport unit 1 and leases 50 percent of Rockport unit 2. AEG sells 70 percent of the power from its share of each unit to I&M. In 2020, AEG billed I&M $40,342,749 in energy charges and $132,450,949 in demand charges for a total of $172,793,698 for 1,413,575 MWh of electricity for AEG's share of Rockport units 1 and 2.[59] These purchased-power costs worked out to a total cost of $122/MWh.[60] This is an exceptionally high cost when compared against the average cost that I&M paid for power from PJM in 2019 of $31.83/MWh.[61]

I&M only received $29,716,111 in energy market revenue for this Rockport energy. When adding in the capacity value of the 917 MW[62] portion of Rockport purchased by I&M under the PPA based on the PJM market capacity value, I find that in 2020 I&M customers paid AEG an estimated $81.45/MWh premium[63] for Rockport's energy and capacity services over the equivalent value of the energy and capacity in the PJM market. This works out to a total $115,134,664 premium that I&M customers are paying AEG for Rockport services. The results are broken out by month in Figure 5 below.

[59] AEG is a subsidiary of AEP and an affiliate of I&M.

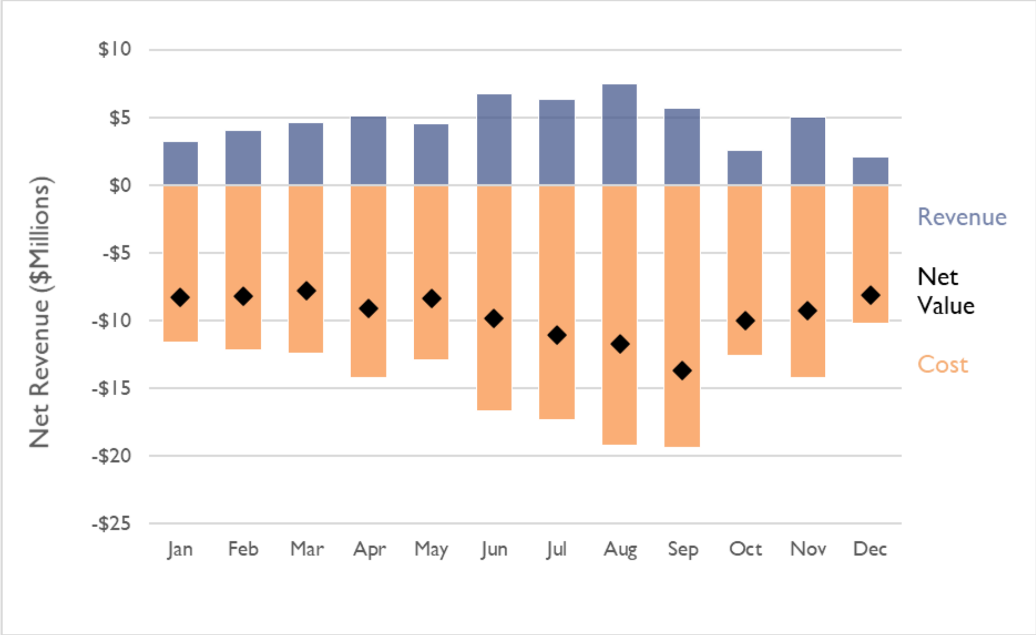
[60] Ex SC-16 I&M Response to Sierra Club Request 4-10, SC 4-10 Attachment 1.

[61] Exhibit IM-3(DHL-1), (p.3), Case No, U-20224.

[62] I&M Exhibit IM-6.

[63] I&M Response to Sierra Club Request 4-10, SC 4-10 Attachment 1; I&M Response to Sierra Club Request 4-11, SC 4-11 Attachment 1. State of the Market Report for PJM, January through September (2020), available online at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020q3-som-pjm.pdf.

Figure 5: AEG billing and I&M revenue from Rockport energy and capacity purchased under PPA (2020)



Source: I&M Response to Sierra Club Request 4-10, SC 4-10 Attachment 1; I&M Response to Sierra Club Request 4-11, SC 4-11 Attachment 1. State of the Market Report for PJM, January through September (2020).

Q Can these findings be used to estimate the net cost associated with I&M's entire share of Rockport?

A Yes. The energy charges billed by AEG on a $/MWh basis should roughly represent the variable cost of operating the plants, while the demand charge on a $/MWh basis should represent the fixed and capital costs. These charges can be scaled up to estimate the costs associated with I&M's combined 85 percent share of Rockport that it owns, leases, and purchases through a PPA.

This works out to $25,078,131 in variable net losses relative to the market that I&M ratepayers paid in 2020. This value is comparable to the variable losses I calculated above based on hourly generation data. Adding in the value of Rockport's capacity, I&M paid $279,612,755 above the market value of Rockport's energy and capacity on a total unit cost basis in 2020. This represents the significant cost premium that

I&M incurred for its ratepayers in 2020 from the uneconomic operation of Rockport units 1 and 2.

Table 2: Rockport charges and revenues for 2020

	Billed to I&M by AEG	**Total I&M share (including owned and leased portion)**
Percent of Rockport Plan	35%	85%
Generation (MWh)	1,413,575	3,432,968
Capacity (MW)	917	2227
Energy charges	$40.3	$98.0
Demand charges	$132.5	$321.7
Total charges	$172.8	$419.6
Energy market revenue	$30.0	$72.9
Capacity value	$27.6	$67.1
Total value	$57.7	$140.0
Net margin	**($115.1)**	**($279.6)**
Net energy margin (loss)	**($10.3)**	**($25.1)**

Source: I&M Response to Sierra Club Request 4-10, SC 4-10 Attachment 1; I&M Response to Sierra Club Request 4-11, SC 4-11 Attachment 1. State of the Market Report for PJM, January through September (2020).

iii. <u>I&M's latest fuel cost plan and five-year forecast indicates that it intends to continue its uneconomic operation and commitment practices at the Rockport units.</u>

Q How does I&M model the operation of the Rockport units for the purposes of its PSCR plan?

A I&M models the Rockport units as committed and dispatched economically into the market and operating only when market revenue exceed unit costs for the purposes of making its PSCR plan.[64]

[64] I&M Response to Sierra Club Request 2-10a.

Q How has I&M historically operated the Rockport Units?

A Analysis performed in the most recent reconciliation docket, Cause U-20224 found that I&M regularly self-commits Rockport Units 1 and 2 and does not in fact economically commit the units.[65] In fact, the units were committed as must-run the majority of the time that they were available in 2019.[66] This behavior resulted in unnecessary net losses being passed on to I&M customers.

Q Why is it concerning for ratepayers that I&M is using a must-run commitment status at its coal-fired generating units so frequently?

A I&M should be committing its units economically into the market. It is only reasonable for I&M to take control of its unit commitment decisions from the market-based PJM algorithm if the utility demonstrates that its internal price-based analysis process produces greater net revenues and a more-economic outcome for ratepayers than relying solely on the PJM market. But I&M has not demonstrated this to be the case. This means the Company is either ignoring the results of its own analysis or bidding the units into the market at a cost below the units' true marginal cost.

This is concerning because if and when I&M commits a unit in PJM uneconomically (that is with variable costs above the market LMP), I&M is only paid by PJM based on the market LMP.[67] But the full cost is still incurred by I&M to run that plant. This means that the fuel costs not economically incurred are passed on to I&M ratepayers in their monthly bills through the PSCR clause.

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[65] Direct Testimony of Sierra Club Witness Devi Glick, page 12. Cause No. U-20224.
[66] *Id.*
[67] The market revenue I&M receives includes energy and ancillary market revenue from both the day-ahead and real-time markets.

Q Are the units projected to operate economically on a forward-going basis?

A No. The Rockport units are projected to incur [[[redacted]]] (present value) in costs relative to the market value of energy and capacity based on unit cost data over the next five years, or an average of [[[redacted]]] per year (as shown in [[[redacted]]]).[68] Note that the drop in both costs and revenues in 2023 occurs when both I&M's lease with Rockport 2 and its PPA with AEG's to purchase power from Rockport 2 ends.

[[[redacted]]

Source: I&M response to Sierra Club Request 1-20, SC 1-20 CONFIDENTIAL Supplemental Attachment 1; I&M Response to Sierra Club Request 4-07, SC 4.07 Attachment 1; I&M Response to Sierra Club Request 1-26, SC 1-26 1H2019 Base Attachment 3; US. EIA, Generating Unit Annual Capital and Life Extension Costs Analysis, December 2019.

[68] I&M response to Sierra Club Request 1-20, SC 1-20 CONFIDENTIAL Supplemental Attachment 1; I&M Response to Sierra Club Request 4-07, SC 4.07 Attachment 1; I&M Response to Sierra Club Request 1-26, SC 1-26 1H2019 Base Attachment 3; US. EIA, Generating Unit Annual Capital and Life Extension Costs Analysis, December 2019. Accessible https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

Q How did you calculate these values?

A I calculated projected generation over the next five years using the forecasted capacity factors supplied by the Company.[69] I&M refused to provide fixed and capital cost projection, so I used the EIA's technology and age-specific values to estimate the units' costs,[70] and applied them to the ICAP values provide by the Company[71] to get the total fixed costs. I combined these with the fuel and variable costs I&M provided to get total forward-going costs for the units. I calculated capacity revenue using the ICAP values I&M provided and the capacity price forecast from I&M's 2019 fundamental forecast. I added that to energy market revenue, which I calculated based on the power market prices in I&M's fundamental forecast.[72] I compared total costs to total revenues to find the units' net revenues.

iv. The Commission should not allow I&M to develop its PSCR plan in this or any future PSCR docket assuming continued uneconomic operation of the Rockport units or extension of the lease at Rockport 2 without contemporaneous analysis.

Q Do you have any recommendations for the Commission related to Rockport unit 2?

A Yes. Though the Company has indicated its intent not to renew the lease for Rockport unit 2 when it expires in December 2022,[73] it could still decide to

[69] I&M response to Sierra Club Request 1-20, SC 1-20 CONFIDENTIAL Supplemental Attachment 1.

[70] US. EIA, Generating Unit Annual Capital and Life Extension Costs Analysis, December 2019. Accessible at https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

[71] I&M Response to Sierra Club Request 4-07, SC 4.07 Attachment 1.

[72] I&M Response to Sierra Club Request 1-26, SC 1-26 1H2019 Base Attachment 3.

[73] I&M Response to Sierra Club 3-1b, SC 3-1b Attachment 1.

negotiate an extension or enter into a new purchase agreement with the Rockport unit 2 owners (or another party if the unit is sold or leased to another entity). Given that unit's recent economic performance, and the Company's projected forward-going economics, the Commission should caution I&M that if the Company extends its lease or enters into a new purchase agreement with the current Rockport unit 2 owners (or any future owners or lessors) without contemporaneous approval of that lease or purchase agreement decision, the Commission may disallow recovery of all or part of those costs in future proceedings.

Q What do you recommend regarding I&M's forecasting of future costs incurred at the Rockport units and included in its PSCR plan?

A The Commission should not approve I&M's PSCR plan to the extent it is developed around the assumption that it will continue to operate Rockport 1 and 2 uneconomically. I&M should instead only be allowed to include in the PSCR plan costs incurred up to the equivalent market value of the power, as determined by the value of energy, ancillary services, and market prices for capacity as delivered from Rockport. In other words, I&M should plan to operate its power plants efficiently and should not plan to run Rockport when cheaper energy is available from the PJM market.

Q Does this conclude your testimony?

A Yes.

Devi Glick, Senior Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-453-7050
dglick@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate*, April 2019 – Present, *Associate*, January 2018 – March 2019

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Providing expert testimony in rate cases on the prudence of continued investment in, and operation of, coal plants based on the economics of plant operations relative to market prices and alternative resource costs.
- Providing expert testimony and analysis on the reasonableness of utility coal plant commitment and dispatch practice in fuel and power cost adjustment dockets.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents in Arizona, Kentucky, New Mexico, Florida, South Carolina, North Carolina, South Africa, Newfoundland, and Nova Scotia for expert reports.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017
Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.
- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Eash-Gates, P., D. Glick, S. Kwok. R. Wilson. 2020. *Orlando's Renewable Energy Future: The Path to 100 Percent Renewable Energy by 2020.* Synapse Energy Economics for the First 50 Coalition.

Eash-Gates, P., B. Fagan, D. Glick. 2020. *Alternatives to the Surry-Skiffes Creek 500 kV Transmission Line.* Synapse Energy Economics for the National Parks Conservation Association.

Biewald, B., D. Glick, J. Hall, C. Odom, C. Roberto, R. Wilson. 2020. *Investing in Failure: How Large Power Companies are Undermining their Decarbonization Targets.* Synapse Energy Economics for Climate Majority Project.

Glick, D., D. Bhandari, C. Roberto, T. Woolf. 2020. *Review of benefit-cost analysis for the EPA's proposed revisions to the 2015 Steam Electric Effluent Limitations Guidelines.* Synapse Energy Economics for Earthjustice and Environmental Integrity Project.

Camp, E., B. Fagan, J. Frost, N. Garner, D. Glick, A. Hopkins, A. Napoleon, K. Takahashi, D. White, M. Whited, R. Wilson. 2019. *Phase 2 Report on Muskrat Falls Project Rate Mitigation, Revision 1 – September 25, 2019.* Synapse Energy Economics for the Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Camp, E., A. Hopkins, D. Bhandari, N. Garner, A. Allison, N. Peluso, B. Havumaki, D. Glick. 2019. *The Future of Energy Storage in Colorado: Opportunities, Barriers, Analysis, and Policy Recommendations.* Synapse Energy Office for the Colorado Energy Office.

Glick, D., B. Fagan, J. Frost, D. White. 2019. *Big Bend Analysis: Cleaner, Lower-Cost Alternatives to TECO's Billion-Dollar Gas Project*. Synapse Energy Economics for Sierra Club.

Glick, D., F. Ackerman, J. Frost. 2019. *Assessment of Duke Energy's Coal Ash Basin Closure Options Analysis in North Carolina.* Synapse Energy Economics for the Southern Environmental Law Center.

Glick, D., N. Peluso, R. Fagan. 2019. *San Juan Replacement Study: An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station*. Synapse Energy Economics for Sierra Club.

Suphachalasai, S., M. Touati, F. Ackerman, P. Knight, D. Glick, A. Horowitz, J.A. Rogers, T. Amegroud. 2018. *Morocco – Energy Policy MRV: Emission Reductions from Energy Subsidies Reform and Renewable Energy Policy.* Prepared for the World Bank Group.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation.* Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan.* Synapse Energy Economics for Centre for Environmental Rights.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for the Natural Resources Defense Council.

Knight, P., E. Camp, D. Glick, M. Chang. 2018. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act*. Supplement to 2018 AESC Study. Synapse Energy Economics for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection.

Fagan, B., R. Wilson, S. Fields, D. Glick, D. White. 2018. *Nova Scotia Power Inc. Thermal Generation Utilization and Optimization: Economic Analysis of Retention of Fossil-Fueled Thermal Fleet to and Beyond 2030 – M08059*. Prepared for Board Counsel to the Nova Scotia Utility Review Board.

Ackerman, F., D. Glick, T. Vitolo. 2018. *Report on CCR proposed rule*. Prepared for Earthjustice.

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EP*A. NextGen Climate America.

Smith, O., M. Lehrman, D. Glick. 2014. *Rate Design for the Distribution Edge*. Rocky Mountain Institute.

Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

TESTIMONY

Public Utility Commission of Texas (PUC Docket No. 50997): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to reconcile fuel costs for the period May 1, 2017- December 31, 2019. On behalf of Sierra Club. January 7, 2021.

Michigan Public Service Commission (Docket No. U-20224): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan (Case No. U-20223) for the 12-month period ending December 31, 2019. On behalf of Sierra Club. October 23, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Surrebuttal Testimony of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 29, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Surrebuttal Testimony of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 21, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Direct Testimony and Exhibits of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 18, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Direct Testimony and Exhibits of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC125): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. September 4, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123 S1): Direct Testimony and Exhibits of Devi Glick in the Subdocket for review of Duke Energy Indian, LLC's Generation Unit Commitment Decisions. On behalf of Sierra Club. July 31, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC124): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. June 4, 2020.

Arizona Corporation Commission (Docket No. E-01933A-19-0028): Rely to Late-filed ACC Staff Testimony of Devi Glick in the application of Tucson Electric Power Company for the establishment of just and reasonable rates. On behalf of Sierra Club. May 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. March 6, 2020.

Texas Public Utility Commission (PUC Docket No. 49831): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

Nova Scotia Utility and Review Board (Matter M09420): Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power's Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Direct Testimony of Devi Glick regarding Southwestern Public Service Company's application for revision of its retail rates and authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

North Carolina Utilities Commission (Docket No. E-100, Sub 158): Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

State Corporation Commission of Virginia (Case No. PUR-2018-00195): Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petition to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

Connecticut Siting Council (Docket No. 470B): Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 12, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Resume updated March 2021

ANNUAL REPORT — 2019

OHIO VALLEY ELECTRIC CORPORATION

and subsidiary

INDIANA-KENTUCKY ELECTRIC CORPORATION

Ohio Valley Electric Corporation

GENERAL OFFICES, 3932 U.S. Route 23, Piketon, Ohio 45661

Ohio Valley Electric Corporation (OVEC) and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC), collectively, the Companies, were organized on October 1, 1952. The Companies were formed by investor-owned utilities furnishing electric service in the Ohio River Valley area and their parent holding companies for the purpose of providing the large electric power requirements projected for the uranium enrichment facilities then under construction by the Atomic Energy Commission (AEC) near Portsmouth, Ohio.

OVEC, AEC and OVEC's owners or their utility-company affiliates (called Sponsoring Companies) entered into power agreements to ensure the availability of the AEC's substantial power requirements. On October 15, 1952, OVEC and AEC executed a 25-year agreement, which was later extended through December 31, 2005 under a Department of Energy (DOE) Power Agreement. On September 29, 2000, the DOE gave OVEC notice of cancellation of the DOE Power Agreement. On April 30, 2003, the DOE Power Agreement terminated in accordance with the notice of cancellation.

OVEC and the Sponsoring Companies signed an Inter-Company Power Agreement (ICPA) on July 10, 1953, to support the DOE Power Agreement and provide for excess energy sales to the Sponsoring Companies of power not utilized by the DOE or its predecessors. Since the termination of the DOE Power Agreement on April 30, 2003, OVEC's entire generating capacity has been available to the Sponsoring Companies under the terms of the ICPA. The Sponsoring Companies and OVEC entered into an Amended and Restated ICPA, effective as of August 11, 2011, which extends its term to June 30, 2040.

OVEC's Kyger Creek Plant at Cheshire, Ohio, and IKEC's Clifty Creek Plant at Madison, Indiana, have nameplate generating capacities of 1,086,300 and 1,303,560 kilowatts, respectively. These two generating stations, both of which began operation in 1955, are connected by a network of 705 circuit miles of 345,000-volt transmission lines. These lines also interconnect with the major power transmission networks of several of the utilities serving the area.

The current Shareholders and their respective percentages of equity in OVEC are:

Allegheny Energy, Inc.[1]	3.50
American Electric Power Company, Inc.*	39.17
Buckeye Power Generating, LLC[2]	18.00
The Dayton Power and Light Company[3]	4.90
Duke Energy Ohio, Inc.[4]	9.00
Kentucky Utilities Company[5]	2.50
Louisville Gas and Electric Company[5]	5.63
Ohio Edison Company[1]	0.85
Ohio Power Company**[6]	4.30
Peninsula Generation Cooperative[7]	6.65
Southern Indiana Gas and Electric Company[8]	1.50
The Toledo Edison Company[1]	4.00
	100.00

The Sponsoring Companies are each either a shareholder in the Company or an affiliate of a shareholder in the Company, with the exception of Energy Harbor Corp. The Sponsoring Companies currently share the OVEC power participation benefits and requirements in the following percentages:

Allegheny Energy Supply Company LLC[1]	3.01
Appalachian Power Company[6]	15.69
Buckeye Power Generating, LLC[2]	18.00
The Dayton Power and Light Company[3]	4.90
Duke Energy Ohio, Inc.[4]	9.00
Energy Harbor Corp	4.85
Indiana Michigan Power Company[6]	7.85
Kentucky Utilities Company[5]	2.50
Louisville Gas and Electric Company[5]	5.63
Monongahela Power Company[1]	0.49
Ohio Power Company[6]	19.93
Peninsula Generation Cooperative[7]	6.65
Southern Indiana Gas and Electric Company[8]	1.50
	100.00

Some of the Common Stock issued in the name of:

*American Gas & Electric Company
**Columbus and Southern Ohio Electric Company

Subsidiary or affiliate of:
[1]FirstEnergy Corp.
[2]Buckeye Power, Inc.
[3]The AES Corporation
[4]Duke Energy Corporation
[5]PPL Corporation
[6]American Electric Power Company, Inc.
[7]Wolverine Power Supply Cooperative, Inc.
[8]CenterPoint Energy, Inc.

A Message from the President

Ohio Valley Electric Corporation (OVEC) and its subsidiary, Indiana-Kentucky Electric Corporation (IKEC), achieved another year of improved unit availability, safety results and strong operating performance in 2019. Results are solely due to the great work of our employees and their efforts in creating a zero-harm culture, focusing on environmental stewardship, and using continuous improvement and LEAN tools to improve operating metrics and create cost optimization. OVEC-IKEC's strategic business plan continues to guide our efforts for "better" and improving our culture.

For 2020, we face the new challenge of COVID-19 and its impact on our business, our industry and our way of life. The OVEC-IKEC team has stepped up to this challenge. Our employees have shown amazing perseverance while working in this new environment and continue to remain focused on achieving our goals of being a safe, reliable and environmentally compliant provider of choice.

SAFETY

Our commitment to providing a safe and healthy place to work for all employees begins with ensuring that each employee returns home safely at the end of every day. Clifty Creek employees completed two years with no recordable injuries in March 2020. System Office employees have worked over 16 years without a lost-time injury. Electrical Operations have completed five years with no recordable injuries in April 2020. The company recordable and DART incident rates trended down in 2019 from the previous year, with year-end rates being 0.88 and 0.35, respectively. The goal is unchanged, zero-harm is the target.

Effective and quality coaching in the field continues as a focus with our ongoing Supervisor Field Observation safety training program. In alignment with Strategic Plan initiatives, a new safety training process including online training options is being to implemented to allow employees to receive key and required training in more than one format. In 2020, we will continue to strive to create and sustain a zero-harm culture for all working at OVEC-IKEC.

CULTURE

OVEC-IKEC remains on its continuous journey of culture improvement. Beginning in 2016, the company has seen significant improvement from the initial survey, with 2019 yielding a 15% improvement over 2018 results. OVEC-IKEC believes investing in culture improvement to engage our people will be the key to our long-term success. For 2020, an updated survey will allow our teams to continue to focus on opportunities and, with engagement of employees, create updated culture action plans to enable improvement.

RELIABILITY

In 2019, the combined equivalent availability of the five generating units at Kyger Creek and the six units at Clifty Creek was 78.2 percent compared with 76.6 percent in 2018. The combined equivalent forced outage rate (EFOR) at both plants was 5.8 percent in 2019 compared with 6.6 percent in 2018.

Through May 2020, the combined EFOR of the eleven generating units was 4 percent.

ENERGY SALES

OVEC's use factor — the ratio of power scheduled by the Sponsoring Companies to power available — for the combined on- and off-peak periods averaged 76.2 percent in 2019 compared with 84.2 percent in 2018. The on-peak use factor averaged 87.4 percent in 2019 compared with 92.1 percent in 2018. The off-peak use factor averaged 61.8 percent in 2019 and 74.0 percent in 2018.

In 2019, OVEC delivered 11.2 million megawatt hours (MWh) to the Sponsoring Companies under the terms of the Inter-Company Power Agreement compared with 11.8 million MWh delivered in 2018.

POWER COSTS

In 2019, OVEC's average power cost to the Sponsoring Companies was $57.04 per MWh compared with $54.29 per MWh in 2018. The total Sponsoring Company power costs were $641 million in 2019 compared with $644 million in 2018.

2020 ENERGY SALES OUTLOOK

COVID-19's impact on an already depressed energy market has caused historically low energy prices and weak demand, which has resulted in reduced OVEC generation compared to traditional results. OVEC's total generation through June was approx. 3.9 million MWh compared to approximately 5.2 million MWh through June 2019. OVEC's updated projection for 2020, which assumes some incremental improvement in the energy demand by the end of the year, is projected at approximately 9 million MWh of generation.

COST CONTROL INITIATIVES

The OVEC and IKEC employees continue to strive to control costs and improve operating performance through application of its continuous improvement process (CIP). Since 2013, CIP has obtained over $26.5 million in sustainable savings through implementation of over 4,000 process improvements. Employee-driven process improvements and a continued effort in hands-on skill development with CIP and LEAN tools throughout the Company are driving the sustainability of the continuous improvement efforts.

In 2019, OVEC-IKEC continued utilizing the LEAN tool of Open Book Leadership (OBL) as a cost-control initiative to further improve our culture and overall business success. OBL is a management philosophy that focuses on empowering employees by providing them the information, education and communication necessary to understand how the Company performs and how they can impact that performance. The OBL process creates transparency of Company performance and engages employees in their ability to impact and improve key performance areas.

For 2020, OVEC is working to optimize operating cost and available generation, during this unprecedented time.

ENVIRONMENTAL COMPLIANCE

OVEC-IKEC continues to maintain a strong commitment to meeting all applicable federal, state and local environmental rules and regulations. During 2019, OVEC operated in substantial compliance with the Mercury Air Toxics Standards (MATS), the Cross-State Air Pollution Rule (CSAPR) and other applicable state and federal air, water and solid waste regulations. In addition, for the third consecutive year, OVEC successfully met the challenge of operating in compliance with the more stringent ozone season NO_x constraints that went into effect with the 2017 ozone season with the adoption of EPA's CSAPR Update Rule. The Company is well positioned to continue to operate all SCR controlled units during 2020 and all future ozone seasons within the constraints of the current CSAPR Update Rule.

Clifty Creek and Kyger Creek both continue to sell nearly all of the gypsum produced at each plant into the wallboard market. Clifty Creek has also been successful in marketing some of its fly ash, and OVEC anticipates that market to continue to grow longer term. Kyger Creek will also pursue a marketing agreement for its dry fly ash in 2023 and beyond following the completion of the dry fly ash conversion project at that Station. Due to long-term market interest in gypsum, both plants have also been evaluating options to install barge loading facilities on-site that could provide additional benefits to fly ash and boiler slag marketing.

During the third year of the Trump Administration, there have been myriad regulatory actions and litigation involving several key environmental regulations impacting the electric utility sector. The regulatory actions include, but are not limited to, continued rulemaking on revising portions of the Steam Electric Effluent Limitations Guidelines (ELG) and associated compliance deadlines, further regulatory actions to the Coal Combustion Residuals (CCR) rule, and state regulatory action to implement the federal Affordable Clean Energy (ACE) rule. OVEC-IKEC will be engaging in multi-year environmental compliance activities to meet requirements in the new ELG and CCR rule revisions, anticipated to become final in 2020. OVEC will also continue to monitor and evaluate the impacts of the associated litigation involving these and other environmental rules impacting the utility sector.

In the interim, the Company continues to work toward meeting various compliance obligations associated with the current CCR rule, the current ELG rule applicable to dry fly ash conversion at the Kyger Creek Station and the Clean Water Act Section 316(b) regulations applicable to both facilities.

FIRSTENERGY SOLUTIONS BANKRUPTCY

On May 18, 2020, OVEC executed a settlement agreement (in the form of a joint stipulation) with Energy Harbor (formerly FirstEnergy Solutions) with respect to all claims in bankruptcy and related litigation. The settlement provided for Energy Harbor to pay OVEC $32.5 million to settle any cure costs associated with prior defaults and to assume its share (4.85%) of the Inter-Company Power Agreement (ICPA) as of June 1, 2020, and be obligated to perform its obligations under the ICPA going forward. The settlement agreement was approved by the Bankruptcy Court on June 15, 2020, and became fully effective on June 30, 2020.

BOARD OF DIRECTORS AND OFFICERS CHANGES

On April 28, 2020, Mr. Dan Arbough, treasurer at LG&E and KU Energy, LLC, was elected a director of OVEC following the resignation of Mr. Paul W. Thompson. Mr. Thompson had served as an OVEC director since 2001. Also, Mr. Lonnie Bellar, Chief Operating Officer at LG&E and KU Energy, LLC, was appointed as a member of the Human Resource Committee, replacing Mr. Thompson.

Paul Chodak
President

July 24, 2020

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2019 AND 2018

	2019	2018
ASSETS		
ELECTRIC PLANT:		
At original cost	$ 2,793,490,793	$ 2,785,266,305
Less—accumulated provisions for depreciation	1,563,780,062	1,500,183,895
	1,229,710,731	1,285,082,410
Construction in progress	13,208,832	11,073,112
Total electric plant	1,242,919,563	1,296,155,522
CURRENT ASSETS:		
Cash and cash equivalents	32,241,171	47,523,556
Accounts receivable	74,486,689	64,278,896
Fuel in storage	61,351,858	33,474,186
Emission allowances	291,681	298,355
Materials and supplies	40,931,063	40,634,643
Income taxes receivable	2,307,853	4,690,064
Property taxes applicable to future years	3,150,000	3,062,500
Prepaid expenses and other	2,817,715	2,175,905
Total current assets	217,578,030	196,138,105
REGULATORY ASSETS:		
Unrecognized postemployment benefits	5,201,536	4,147,956
Unrecognized pension benefits	32,170,308	33,894,325
Decommissioning, demolition and other	-	5,902,867
Total regulatory assets	37,371,844	43,945,148
DEFERRED CHARGES AND OTHER:		
Unamortized debt expense	688,643	156,683
Long-term investments	240,739,279	181,271,533
Income taxes receivable	2,307,341	4,614,683
Other	2,510,636	1,245,637
Total deferred charges and other	246,245,899	187,288,536
TOTAL	$ 1,744,115,336	$ 1,723,527,311

(Continued)

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2019 AND 2018

	2019	2018
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common stock, $100 par value—authorized, 300,000 shares; outstanding, 100,000 shares in 2019 and 2018	$ 10,000,000	$ 10,000,000
Long-term debt	1,119,568,409	1,110,069,775
Line of credit borrowings	80,000,000	-
Retained earnings	17,294,023	14,238,732
Total capitalization	1,226,862,432	1,134,308,507
CURRENT LIABILITIES:		
Current portion of long-term debt	141,387,803	179,670,116
Line of credit borrowings	-	85,000,000
Accounts payable	34,871,926	41,313,387
Accrued other taxes	10,527,047	10,725,765
Regulatory liabilities	7,677,404	7,657,791
Accrued interest and other	27,532,934	20,663,191
Total current liabilities	221,997,114	345,030,250
COMMITMENTS AND CONTINGENCIES (Notes 3, 9, 11, and 12)		
REGULATORY LIABILITIES:		
Postretirement benefits	76,162,798	63,659,058
Income taxes refundable to customers	8,658,897	11,571,428
Advance billing of debt reserve	90,000,000	60,000,000
Decommissioning, demolition and other	14,718,161	-
Total regulatory liabilities	189,539,856	135,230,486
OTHER LIABILITIES:		
Pension liability	32,170,308	33,894,325
Asset retirement obligations	63,487,038	60,246,682
Postretirement benefits obligation	4,242,848	10,186,597
Postemployment benefits obligation	5,201,536	4,147,956
Other non-current liabilities	614,204	482,508
Total other liabilities	105,715,934	108,958,068
TOTAL	$ 1,744,115,336	$ 1,723,527,311

See notes to consolidated financial statements. (Concluded)

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

	2019	2018
REVENUES FROM CONTRACTS WITH CUSTOMERS—Sales of electric energy to:		
Department of Energy	$ 4,641,167	$ 7,605,922
Sponsoring Companies	606,993,408	608,233,419
Other	3,033,066	-
Total revenues from contracts with customers	614,667,641	615,839,341
OPERATING EXPENSES:		
Fuel and emission allowances consumed in operation	274,843,402	277,368,623
Purchased power	3,735,333	6,863,294
Other operation	91,611,162	86,302,869
Maintenance	87,208,116	86,305,942
Depreciation	88,825,066	54,190,596
Taxes—other than income taxes	11,330,963	12,164,929
Income taxes	(2,912,531)	-
Total operating expenses	554,641,511	523,196,253
OPERATING INCOME (LOSS)	60,026,130	92,643,088
OTHER INCOME (EXPENSE)	24,280,007	(5,921,972)
INCOME BEFORE INTEREST CHARGES	84,306,137	86,721,116
INTEREST CHARGES:		
Amortization of debt expense	4,204,163	4,143,079
Interest expense	77,046,683	78,681,556
Total interest charges	81,250,846	82,824,635
NET INCOME	3,055,291	3,896,481
RETAINED EARNINGS—Beginning of year	14,238,732	10,342,251
RETAINED EARNINGS—End of year	$ 17,294,023	$ 14,238,732

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

	2019	2018
OPERATING ACTIVITIES:		
Net income	$ 3,055,291	$ 3,896,481
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation	88,825,066	54,190,596
Amortization of debt expense	4,204,163	4,143,079
Loss (gain) on marketable securities	(16,672,791)	13,147,621
Changes in assets and liabilities:		
Accounts receivable	(10,207,793)	(23,544,559)
Fuel in storage	(27,877,672)	342,925
Materials and supplies	(296,420)	(2,189,366)
Property taxes applicable to future years	(87,500)	(150,000)
Emissions allowances	6,674	57,497
Income tax receivable	2,382,211	65,545
Prepaid expenses and other	(641,810)	(123,945)
Other regulatory assets	9,392,126	(1,146,702)
Other noncurrent assets	1,042,342	(1,244,103)
Accounts payable	(5,360,967)	10,589,698
Accrued taxes	(198,718)	(148,768)
Accrued interest and other	6,869,743	(5,021,649)
Decommissioning, demolition and other	11,899,339	3,076,062
Other liabilities	(3,242,134)	(10,203,483)
Other regulatory liabilities	15,662,796	43,646,969
Net cash provided by operating activities	78,753,946	89,383,898
INVESTING ACTIVITIES:		
Electric plant additions	(12,474,714)	(8,439,941)
Proceeds from sale of long-term investments	55,360,283	71,570,881
Purchases of long-term investments	(98,155,238)	(111,716,117)
Net cash (used in) provided by investing activities	(55,269,669)	(48,585,177)
FINANCING ACTIVITIES:		
Debt issuance and maintenance costs	(3,849,380)	(529,670)
Repayment of Senior 2006 Notes	(22,029,278)	(20,798,412)
Repayment of Senior 2007 Notes	(15,648,462)	(14,759,418)
Repayment of Senior 2008 Notes	(16,992,682)	(15,926,263)
Reissuance 2009A Bonds	25,000,000	-
Redemption of 2009E Bonds	(100,000,000)	-
Issuance of 2019A Bonds	100,000,000	-
Proceeds from line of credit	10,000,000	-
Payments on line of credit	(15,000,000)	-
Principal payments under capital leases	(246,860)	(239,492)
Net cash (used in) provided by financing activities	(38,766,662)	(52,253,255)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(15,282,385)	(11,454,534)
CASH AND CASH EQUIVALENTS—Beginning of year	47,523,556	58,978,090
CASH AND CASH EQUIVALENTS—End of year	$ 32,241,171	$ 47,523,556
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:		
Interest paid	$ 75,703,531	$ 81,777,903
Income taxes (received) paid—net	$ (4,690,064)	$ (74,784)
Non-cash electric plant additions included in accounts payable at December 31	$ 58,516	$ 892,150

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

1. ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Consolidated Financial Statements—The consolidated financial statements include the accounts of Ohio Valley Electric Corporation (OVEC) and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC), collectively, the Companies. All intercompany transactions have been eliminated in consolidation.

Organization—The Companies own two generating stations located in Ohio and Indiana with a combined electric production capability of approximately 2,256 megawatts. OVEC is owned by several investor-owned utilities or utility holding companies and two affiliates of generation and transmission rural electric cooperatives. These entities or their affiliates comprise the Sponsoring Companies. The Sponsoring Companies purchase power from OVEC according to the terms of the Inter-Company Power Agreement (ICPA), which has a current termination date of June 30, 2040. Approximately 24% of the Companies' employees are covered by a collective bargaining agreement that expires on August 31, 2021.

Prior to 2004, OVEC's primary commercial customer was the U.S. Department of Energy (DOE). The contract to provide OVEC-generated power to the DOE was terminated in 2003 and all obligations were settled at that time. Currently, OVEC has an agreement to arrange for the purchase of power (Arranged Power), under the direction of the DOE, for resale directly to the DOE. The current agreement with the DOE was executed on July 11, 2018, for one year, with the option for the DOE to extend the agreement at the anniversary date. The agreement was extended on July 11, 2019, for one year. OVEC anticipates that this agreement will continue until 2022. All purchase costs are billable by OVEC to the DOE.

Rate Regulation—The proceeds from the sale of power to the Sponsoring Companies are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, as well as earn a return on equity before federal income taxes. In addition, the proceeds from power sales are designed to cover debt amortization and interest expense associated with financings. The Companies have continued and expect to continue to operate pursuant to the cost-plus rate of return recovery provisions at least to June 30, 2040, the date of termination of the ICPA. In 2014, to promote reduced costs, the Companies reduced their billings under the ICPA to effectively forego recovery of the equity return through the ICPA billings. However, in 2018, the Companies discontinued this practice and are once again recovering the equity return through the ICPA billings.

The accounting guidance for Regulated Operations provides that rate-regulated utilities account for and report assets and liabilities consistent with the economic effect of the way in which rates are established, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected. The Companies follow the accounting and reporting requirements in accordance with the guidance for Regulated Operations. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred in the accompanying consolidated balance sheets and are recognized as income as the related amounts are included in service rates and recovered from or refunded to customers.

The Companies' regulatory assets, liabilities, and amounts authorized for recovery through Sponsor billings at December 31, 2019 and 2018, were as follows:

	2019	2018
Regulatory assets:		
Noncurrent regulatory assets:		
Unrecognized postemployment benefits	$ 5,201,536	$ 4,147,956
Unrecognized pension benefits	32,170,308	33,894,325
Decommissioning, demolition and other	-	8,721,689
Total	37,371,844	46,763,970
Total regulatory assets	$ 37,371,844	$ 46,763,970
Regulatory liabilities:		
Current regulatory liabilities:		
Deferred revenue—advances for construction	$ 6,182,811	$ 6,024,309
Deferred credit—advance collection of interest	1,494,593	1,633,482
Total	7,677,404	7,657,791
Noncurrent regulatory liabilities:		
Postretirement benefits	76,162,798	63,659,058
Income taxes refundable to customers	8,658,897	11,571,428
Advance billing of debt reserve	90,000,000	60,000,000
Decommissioning, demolition and other	14,718,161	2,818,822
Total	189,539,856	138,049,308
Total regulatory liabilities	$ 197,217,260	$ 145,707,099

Regulatory Assets—Regulatory assets consist primarily of pension benefit costs, postemployment benefit costs, and accrued decommissioning and demolition costs to be billed to the Sponsoring Companies in future years. The Companies' current billing policy for pension and postemployment benefit costs is to bill its actual plan funding.

Regulatory Liabilities—The regulatory liabilities classified as current in the accompanying consolidated balance sheet as of December 31, 2019, consist primarily of interest expense collected from customers in advance of expense recognition and customer billings for construction in progress. These amounts will be credited to customer bills during 2020. Other regulatory liabilities consist primarily of postretirement benefit costs and decommissioning and demolition costs that have been billed to customers in excess of cumulative expense recognition, income taxes refundable to customers that will be credited to bills over a long-term basis, and advanced billings collected from the Sponsoring Companies for debt service.

The regulatory liability for postretirement benefits recorded at December 31, 2019 and 2018, represents amounts collected in historical billings in excess of the accounting principles generally accepted in the United States of America (GAAP) net periodic benefit costs, including a termination payment from the DOE in 2003 for unbilled postretirement benefit costs, and incremental unfunded plan obligations recognized in the balance sheets but not yet recognizable in GAAP net periodic benefit costs. Related regulatory liabilities are being credited to customer bills on a long-term basis.

In January 2017, the Companies started advance billing the Sponsoring Companies for debt service as allowed under the ICPA. As of December 31, 2019 and 2018, $90 million and $60 million, respectively, had been advance billed to the Sponsoring Companies. As the Companies have not yet incurred the related costs, a regulatory liability was recorded which will be credited to customer bills on a long-term basis.

Cash and Cash Equivalents—Cash and cash equivalents primarily consist of cash and money market funds and their carrying value approximates fair value. For purposes of these statements, the Companies consider temporary cash investments to be cash equivalents since they are readily convertible into cash and have original maturities of less than three months.

Electric Plant—Property additions and replacements are charged to utility plant accounts. Depreciation expense is recorded at the time property additions and replacements are billed to customers or at the date the property is placed in service if the in-service date occurs subsequent to the customer billing. Customer billings for construction in progress are recorded as deferred revenue—advances for construction. These amounts are closed to revenue at the time the related property is placed in service. Depreciation expense and accumulated depreciation are recorded when financed property additions and replacements are recovered over a period of years through customer debt retirement billing. All depreciable property will be fully billed and depreciated prior to the expiration of the ICPA. Repairs of property are charged to maintenance expense.

Fuel in Storage, Emission Allowances, and Materials and Supplies—The Companies maintain coal, reagent, and oil inventories, as well as emission allowances, for use in the generation of electricity for regulatory compliance purposes due to the generation of electricity. These inventories are valued at average cost. Materials and supplies consist primarily of replacement parts necessary to maintain the generating facilities and are valued at average cost.

Long-Term Investments—Long-term investments consist of marketable securities that are held for the purpose of funding decommissioning and demolition costs, debt service, potential postretirement funding, and other costs. These debt securities have been classified as trading securities in accordance with the provisions of the accounting guidance for Investments—Debt and Equity Securities. Debt and equity securities reflected in long-term investments are carried at fair value with the unrealized gain or loss, reported in Other Income (Expense). The cost of securities sold is based on the specific identification cost method. The fair value of most investment securities is determined by reference to currently available market prices. Where quoted market prices are not available, the Companies use the market price of similar types of securities that are traded in the market to estimate fair value. See Fair Value Measurements in Note 10. Long-term investments primarily consist of municipal bonds, money market mutual fund investments, and mutual funds. Net unrealized gains (losses) recognized during 2019 and 2018 on securities still held at the balance sheet date were $16,445,716 and ($12,968,851), respectively.

Fair Value Measurements of Assets and Liabilities—The accounting guidance for Fair Value Measurements and Disclosures establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). Where observable inputs are available, pricing may be completed using comparable securities, dealer values, and general market conditions to determine fair value. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, and other observable inputs for the asset or liability.

Unamortized Debt Expense—Unamortized debt expense relates to costs incurred in connection with obtaining revolving credit agreements. These costs are being amortized over the term of the related revolving credit agreement and are recorded as an asset in the consolidated balance sheets. Costs incurred to issue debt are recorded as a reduction to long-term debt as presented in Note 6.

Asset Retirement Obligations and Asset Retirement Costs—The Companies recognize the fair value of legal obligations associated with the retirement or removal of long-lived assets at the time the obligations are incurred and can be reasonably estimated. The initial recognition of this liability is accompanied by a corresponding increase in depreciable electric plant. Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to electric plant) and for accretion of the liability due to the passage of time.

These asset retirement obligations are primarily related to obligations associated with future asbestos abatement at certain generating stations and certain plant closure costs, including the impacts of the coal combustion residuals rule.

Balance—January 1, 2018	$ 57,170,620
Accretion	3,076,062
Liabilities settled	-
Revisions to cash flows	-
Balance—December 31, 2018	60,246,682
Accretion	3,275,262
Liabilities settled	(34,906)
Revisions to cash flows	-
Balance—December 31, 2019	$ 63,487,038

During 2017, the Companies completed an updated study to estimate the asset retirement costs described above. The revised estimated costs are recorded in the accompanying balance sheets. Adjustments resulting from the revised estimated costs are included as revisions to cash flows in the above table. The increase in the asset retirement obligation is primarily the result of proposed regulations related to the disposal of coal combustion residuals, as further discussed in Note 9.

The Companies do not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. The Companies have asset retirement obligations associated with transmission assets. However, the retirement date for these assets cannot be determined; therefore, the fair value of the associated liability currently cannot be estimated and no amounts are recognized in the consolidated financial statements herein.

Income Taxes—The Companies use the liability method of accounting for income taxes. Under the liability method, the Companies provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities, which will result in a future tax consequence. The Companies account for uncertain tax positions in accordance with the accounting guidance for Income Taxes.

Use of Estimates—The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition—In May 2014, the FASB issued Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09), which provides a new framework for the recognition of revenue. The standard’s core principle is that a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The Companies implemented the guidance on a modified retrospective basis on January 1, 2018. Revenue for the reporting periods beginning after December 31, 2017, are recorded and disclosed in accordance with Topic 606, while prior period results have not been adjusted and continue to be reported in accordance with prior accounting guidance. The Companies did not make any adjustments to the January 1, 2018, opening balances as a result of adoption, and the implementation had no impact on the Companies’ consolidated financial statements.

Performance obligations related to the sale of electric energy are satisfied over time as system resources are made available to customers and as energy is delivered to customers and the Companies recognize revenue upon billing the customer.

The Companies have three contracts with customers resulting in three types of revenue. These three contracted revenue types are:

1) Sales of Electric Energy to Department of Energy
2) Sales of Electric Energy to Sponsoring Companies
3) Sales of Electric Energy to Pennsylvania, Jersey, Maryland Power Pool (PJM)

The performance obligations and recognition of revenue are similar and both individually and, in the aggregate, were not materially impacted by the implementation of Topic 606. The Companies have no contract assets or liabilities as of December 31, 2019. The following table provides information about the Companies' receivables and unbilled revenue from contracts with customers:

	Accounts Receivable	Unbilled
Beginning balance as of January 1, 2018	$ 40,737,337	$ 5,454,632
Ending balance as of December 31, 2018	64,278,896	5,098,515
Increase/(decrease)	$ 23,544,559	$ (356,117)
Beginning balance as of January 1, 2019	$ 64,278,896	$ 5,098,515
Ending balance as of December 31, 2019	$ 74,486,689	$ 5,611,960
Increase/(decrease)	$ 10,207,793	$ 513,445

Recently Issued Accounting Standards—In June 2016, the FASB issued ASU 2016-13, *Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. The pronouncement changes the impairment model for most financial assets, replacing the current "incurred loss" model. ASU 2016-13 will require the use of an "expected loss" model for instruments measured at amortized cost and will also require entities to record allowances for available-for-sale debt securities rather than reduce the carrying amount. The Companies plan to adopt the standard for the fiscal year ended December 31, 2020. The Companies are in the process of evaluating the impact of adoption, if any, of this ASU on the Companies' consolidated financial statements.

See adoption of ASC 842, *Leases*, in Note 11.

Subsequent Events—In preparing the accompanying financial statements and disclosures, the Companies reviewed subsequent events through April 17, 2020, which is the date the consolidated financial statements were issued.

Subsequent to December 31, 2019, the World Health Organization declared the ongoing expansion of an existing outbreak of the SARS-CoV-2 virus, named the coronavirus 2019 ("COVID-19"), a pandemic. As a result of the evolving situation and increasing number of cases, many countries have taken various steps in an attempt to curtail or slow COVID-19's spread, including limiting or ceasing international and domestic travel, slowing or ceasing production activity, and lockdowns or shelter-in-place orders. The Companies are currently unable to predict the duration or extent of any business disruption, changes in law and/or regulation, and uncertainty regarding government and regulatory policy that may occur as a result of these events. COVID-19 has also caused significant volatility and declines in value to most financial markets, which will have a near-term impact on the value of the Companies' long-term investments and investments related to benefit obligations. As there are no comparable recent events which may provide guidance as to the effect of the spread of

COVID-19, the Companies are unable to estimate the impact that COVID-19 will have on its financial results at this time.

2. RELATED-PARTY TRANSACTIONS

Transactions with the Sponsoring Companies during 2019 and 2018 included the sale of all generated power to them, the purchase of Arranged Power from them, and other utility systems in order to meet the DOE’s power requirements, contract barging services, railcar services, and minor transactions for services and materials. The Companies have Power Agreements with Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, Kentucky Utilities Company, Ohio Edison Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies; and Transmission Service Agreements with Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, The Toledo Edison Company, Ohio Edison Company, Kentucky Utilities Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies.

At December 31, 2019 and 2018, balances due from the Sponsoring Companies are as follows:

	2019	2018
Accounts receivable	$ 66,926,922	$ 57,442,759

During 2019 and 2018, American Electric Power accounted for approximately 44% of operating revenues from Sponsoring Companies and Buckeye Power accounted for 18%. No other Sponsoring Company accounted for more than 10%.

American Electric Power Company, Inc. and subsidiary companies owned 43.47% of the common stock of OVEC as of December 31, 2019. The following is a summary of the principal services received from the American Electric Power Service Corporation as authorized by the Companies’ Boards of Directors:

	2019	2018
General services	$ 4,830,104	$ 4,917,608
Specific projects	119,157	472,862
Total	$ 4,949,261	$ 5,390,470

General services consist of regular recurring operation and maintenance services. Specific projects primarily represent nonrecurring plant construction projects and engineering studies, which are approved by the Companies’ Boards of Directors. The services are provided in accordance with the service agreement dated December 15, 1956, between the Companies and the American Electric Power Service Corporation.

3. COAL SUPPLY

The Companies have coal supply agreements with certain nonaffiliated companies that expire at various dates from the year 2020 through 2022. Pricing for coal under these contracts is subject to contract provisions and adjustments. The Companies currently have 100% of their 2020 coal requirements under contract. These contracts are based on rates in effect at the time of contract execution. Our total obligations under these agreements as of December 31, 2019, are included in the table below:

2020	$ 213,126,750
2021	$ 135,876,000
2022	$ 50,340,000

4. ELECTRIC PLANT

Electric plant at December 31, 2019 and 2018, consists of the following:

	2019	2018
Steam production plant	$2,698,568,508	$2,690,743,500
Transmission plant	81,986,558	81,578,790
General plant	12,909,163	12,917,451
Intangible	26,564	26,564
	2,793,490,793	2,785,266,305
Less accumulated depreciation	1,563,780,062	1,500,183,895
	1,229,710,731	1,285,082,410
Construction in progress	13,208,832	11,073,112
Total electric plant	$1,242,919,563	$1,296,155,522

All property additions and replacements are fully depreciated on the date the property is placed in service, unless the addition or replacement relates to a financed project. As the Companies' policy is to bill in accordance with the debt service schedule under the debt agreements, all financed projects are being depreciated in amounts equal to the principal payments on outstanding debt.

5. BORROWING ARRANGEMENTS AND NOTES

OVEC had a $200 million revolving credit facility set to expire in November 2019, which was replaced on April 25, 2019, by a new revolving credit facility of $185 million with an expiration date of April 25, 2022. At December 31, 2019 and 2018, OVEC had borrowed $80 million and $85 million, respectively, under lines of credit. Interest expense related to lines of credit borrowings was $3,757,148 in 2019 and $3,448,137 in 2018. During 2019 and 2018, OVEC incurred annual commitment fees of $268,285 and $318,885, respectively, based on the borrowing limits of the lines of credit.

6. LONG-TERM DEBT

The following amounts were outstanding at December 31, 2019 and 2018:

	Interest Rate Type	Interest Rate	2019	2018
Senior 2006 Notes:				
2006A due February 15, 2026	Fixed	5.80 %	$ 168,569,904	$ 189,381,919
2006B due June 15, 2040	Fixed	6.40	54,142,874	55,360,136
Senior 2007 Notes:				
2007A-A due February 15, 2026	Fixed	5.90	74,610,818	84,386,325
2007A-B due February 15, 2026	Fixed	5.90	18,790,003	21,251,868
2007A-C due February 15, 2026	Fixed	5.90	18,939,620	21,421,088
2007B-A due June 15, 2040	Fixed	6.50	27,012,831	27,630,240
2007B-B due June 15, 2040	Fixed	6.50	6,802,916	6,958,404
2007B-C due June 15, 2040	Fixed	6.50	6,857,084	7,013,810
Senior 2008 Notes:				
2008A due February 15, 2026	Fixed	5.92	23,292,665	26,342,332
2008B due February 15, 2026	Fixed	6.71	47,301,931	53,467,070
2008C due February 15, 2026	Fixed	6.71	49,367,759	55,446,166
2008D due June 15, 2040	Fixed	6.91	39,387,935	40,230,351
2008E due June 15, 2040	Fixed	6.91	40,072,323	40,929,376
Series 2009 Bonds:				
2009A due February 15, 2026	Fixed	2.88	25,000,000	-
2009B due February 1, 2026	Floating	3.31	25,000,000	25,000,000
2009C due February 1, 2026	Floating	3.31	25,000,000	25,000,000
2009D due February 1, 2026	Floating	1.46	25,000,000	25,000,000
2009E due October 1, 2019	Fixed	5.63	-	100,000,000
Series 2010 Bonds:				
2010A due February 1, 2040	Floating	6.23	50,000,000	50,000,000
2010B due February 1, 2040	Floating	3.31	50,000,000	50,000,000
Series 2012 Bonds:				
2012A due June 1, 2032	Fixed	5.00	76,800,000	76,800,000
2012A due June 1, 2039	Fixed	5.00	123,200,000	123,200,000
2012B due June 1, 2040	Floating	6.23	50,000,000	50,000,000
2012C due June 1, 2040	Floating	6.23	50,000,000	50,000,000
Series 2017 Notes:				
2017A due August 4, 2022	Floating	6.23	100,000,000	100,000,000
Series 2019 Bonds:				
2019A due September 1, 2029	Fixed	3.25	100,000,000	-
Total debt			1,275,148,663	1,304,819,085
Total premiums and discounts (net)			(437,865)	(460,465)
Less unamortized debt expense			(13,754,586)	(14,618,729)
Total debt net of premiums, discounts, and unamortized debt expense			1,260,956,212	1,289,739,891

All of the OVEC amortizing unsecured senior notes have maturities scheduled for February 15, 2026, or June 15, 2040, as noted in the previous table.

In 2009, the Ohio Air Quality Development Authority (the "OAQDA") issued the variable-rate, non-amortizing, tax-exempt State of Ohio Air Quality Revenue Bonds (Ohio Valley Electric Corporation Project) in four series (Series 2009A, Series 2009B, Series 2009C and Series 2009D) of $25 million each (the "Series 2009A Bonds," the "Series 2009B Bonds," the "Series 2009C Bonds" and the "Series 2009D Bonds") and $100 million fixed-rate non-amortizing tax-exempt State of Ohio Air Quality Revenue Bonds (Ohio Valley Electric Corporation Project) (the "Series 2009E Bonds"), the proceeds of which were used to finance a portion of OVEC's costs of acquiring, constructing and installing certain solid waste disposal facilities comprising "air quality facilities," as defined in Chapter 3706, Ohio Revised Code, as amended, for Units 1-5 of the Kyger Creek Plant. OVEC is obligated to make payments under loan agreements between OVEC and OAQDA equal to the principal and interest payments due on such bonds, among other payments.

The Series 2009B and Series 2009C Bonds were remarketed in August 2016, for a five-year interest period that extends to August 25, 2021. The Series 2009A Bonds were secured by an irrevocable transferable direct-pay letter of credit at December 31, 2016, but were repurchased by OVEC on February 6, 2017. Further, the Series 2009D Bonds were secured by an irrevocable transferable direct-pay letter of credit that expired on November 14, 2019. On August 14, 2019, the Series 2009A Bonds and Series 2009D Bonds were each reoffered with a fixed interest rate of 2.875% per annum for the period beginning on August 28, 2019 and ending on February 1, 2026. In addition, the Series 2009E Bonds, which were scheduled to mature on October 1, 2019, were refunded with the proceeds of the Series 2019A Bonds (as defined below).

In December 2010, OVEC established a borrowing facility under which OVEC borrowed, in 2011, $100 million variable-rate bonds due on February 1, 2040. In June 2011, the $100 million variable-rate bonds were reissued by the Indiana Finance Authority (the "IFA") as two series of $50 million variable-rate, non-amortizing, tax-exempt bonds: the Series 2010A Bonds, with an interest period of three years and the Series 2010B Bonds, with an interest period of five years. The Series 2010B Bonds were remarketed in August 2016 for another five-year interest period ending on August 25, 2021. The Series 2010A Bonds were remarketed in June 2014 for a three-year period and in September 2017 for another three-year period that extends to August 4, 2020. The Series 2010A Bonds are to be refinanced in 2020. The Series 2010B Bonds are not being reoffered at this time.

During 2012, the IFA issued $200 million fixed-rate, tax-exempt Midwestern Disaster Relief Revenue Bonds (Ohio Valley Electric Corporation Project) (the "Series 2012A Bonds") and two series of $50 million each, variable-rate, tax-exempt bonds: the Series 2012B Bonds and the Series 2012C Bonds. The Series 2012A Bonds will begin amortizing on June 1, 2027, up to its maturity date. OVEC is obligated to make payments under loan agreements between OVEC and the IFA equal to the principal and interest payments due on such bonds, among other payments.

In 2017, the Series 2012B Bonds and the Series 2012C Bonds, which had been secured by irrevocable transferable direct-pay letters of credit, were remarketed with four-year and five-year interest periods expiring August 4, 2021 and August 4, 2022, respectively.

During 2017, OVEC issued $100 million 2017A variable-rate non-amortizing unsecured senior notes ("2017A Notes") to refinance and retire a 2013 series of notes ("2013A Notes"). The 2013A Notes had an original maturity date of February 15, 2018. The 2017A Notes have an annual repayment of $33,333,333 on August 4, 2020, August 4, 2021, and at the maturity date of August 4, 2022.

In August 2019, OVEC refinanced or refunded $150 million in tax-exempt bonds as follows: (i) the OAQDA issued the State of Ohio Air Quality Revenue Refunding Bonds (Ohio Valley Electric Corporation Project), Series 2019A in an aggregate principal amount of $100 million (the "Series 2019A Bonds"), with a fixed interest rate of 3.25% per annum for the period beginning August 28, 2019 to September 1, 2029, the proceeds of which were used to refund the Series 2009E Bonds, (ii) the Series 2009A Bonds were reoffered in an aggregate principal amount of $25 million and (iii) the Series 2009D Bonds were reoffered in an aggregate principal amount of $25 million.

The annual maturities of long-term debt as of December 31, 2019, are as follows:

2020	$ 141,387,803
2021	244,982,570
2022	148,800,891
2023	69,523,395
2024	73,831,592
2025–2040	596,622,412
Total	$1,275,148,663

Note that the 2020 maturities of long-term debt include $50 million variable-rate bonds with agreements expiring in August 2020.

7. INCOME TAXES

OVEC and IKEC file a consolidated federal income tax return. The effective tax rate varied from the statutory federal income tax rate due to differences between the book and tax treatment of various transactions as follows:

	2019	2018
Income tax expense at statutory rate (21% 2019, 21% 2018)	$ 29,980	$ 818,261
Temporary differences flowed through to customer bills	(2,948,492)	(823,343)
Permanent differences and other	5,981	5,082
Income tax provision	$ (2,912,531)	$ -

Components of the income tax provision were as follows:

	2019	2018
Current income tax expense—federal	$ (2,912,531)	$ -
Current income tax (benefit)/expense—state	-	-
Deferred income tax expense/(benefit)—federal	-	-
Total income tax provision	$ (2,912,531)	$ -

OVEC and IKEC record deferred tax assets and liabilities based on differences between book and tax basis of assets and liabilities measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Deferred tax assets and liabilities are adjusted for changes in tax rates.

To the extent that the Companies have not reflected credits in customer billings for deferred tax assets, they have recorded a regulatory liability representing income taxes refundable to customers under the applicable agreements among the parties. These temporary differences will be credited to the Sponsoring Companies through future power billings. The regulatory liability was $8,658,898 and $11,571,429 at December 31, 2019 and 2018, respectively.

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Deferred income tax assets (liabilities) at December 31, 2019 and 2018, consisted of the following:

	2019	2018
Deferred tax assets:		
Deferred revenue—advances for construction	$ 1,299,537	$ 1,265,885
Federal net operating loss carryforwards	39,691,784	49,663,022
Postretirement benefit obligation	891,785	2,140,505
Pension liability	7,034,974	6,447,661
Postemployment benefit obligation	1,093,288	871,608
Asset retirement obligations	13,344,057	12,659,609
Advanced collection of interest and debt service	19,230,828	12,951,016
Miscellaneous accruals	1,154,630	1,183,464
Regulatory liability—postretirement benefits	16,008,318	13,376,650
Regulatory liability—asset retirement costs	3,093,544	-
Regulatory liability—income taxes refundable to customers	4,549,301	5,484,284
Total deferred tax assets	107,392,046	106,043,704
Deferred tax liabilities:		
Prepaid expenses	(384,597)	(352,638)
Electric plant	(81,887,070)	(81,674,810)
Unrealized gain/loss on marketable securities	(4,348,230)	(855,225)
Regulatory asset—pension benefits	(6,719,696)	(7,122,200)
Regulatory asset—asset retirement costs	-	(1,240,367)
Regulatory asset—unrecognized postemployment benefits	(1,093,288)	(871,608)
Total deferred tax liabilities	(94,432,881)	(92,116,848)
Valuation allowance	(12,959,165)	(13,926,856)
Deferred income tax assets	$ -	$ -

Because future taxable income may prove to be insufficient to recover the Companies' deferred tax assets, the Companies have recorded a valuation allowance for their deferred tax assets as of December 31, 2019 and 2018. During 2016, due to a change in federal tax law, the Companies recorded as receivables certain AMT credit carryforwards that the Companies expect to claim as refundable credits in their 2018–2022 federal income tax returns. The amount of the refundable AMT credit is reflected as a current receivable of $2,307,341 and a non-current receivable of $2,307,341 for a total receivable of $4,614,682.

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The accounting guidance for Income Taxes addresses the determination of whether the tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under this guidance, the Companies may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The Companies have not identified any uncertain tax positions as of December 31, 2019 and 2018, and accordingly, no liabilities for uncertain tax positions have been recognized.

The Companies file income tax returns with the Internal Revenue Service and the states of Ohio, Indiana, and the Commonwealth of Kentucky. The Companies are no longer subject to federal tax examinations for tax years 2015 and earlier. The Companies are no longer subject to State of Indiana tax examinations for tax years 2015 and earlier. The Companies are no longer subject to Ohio and the Commonwealth of Kentucky examinations for tax years 2014 and earlier. The Companies have $189,008,494 of Federal Net Operating Loss carryovers that begin to expire in 2032.

8. PENSION PLAN AND OTHER POSTRETIREMENT AND POSTEMPLOYMENT BENEFITS

The Companies have a noncontributory qualified defined benefit pension plan (the Pension Plan) covering substantially all of their employees hired prior to January 1, 2015. The benefits are based on years of service and each employee’s highest consecutive 36-month compensation period. Employees are vested in the Pension Plan after five years of service with the Companies.

Funding for the Pension Plan is based on actuarially determined contributions, the maximum of which is generally the amount deductible for income tax purposes and the minimum being that required by the Employee Retirement Income Security Act of 1974, as amended.

In addition to the Pension Plan, the Companies provide certain health care and life insurance benefits (Other Postretirement Benefits) for retired employees. Substantially, all of the Companies’ employees hired prior to January 1, 2015, become eligible for these benefits if they reach retirement age while working for the Companies. These and similar benefits for active employees are provided through employer funding and insurance policies. In December 2004, the Companies established VEBA trusts. In January 2011, the Companies established an Internal Revenue Code Section 401(h) account under the Pension Plan.

The full cost of the pension benefits and other postretirement benefits has been allocated to OVEC and IKEC in the accompanying consolidated financial statements. The allocated amounts represent approximately a 56% and 44% split between OVEC and IKEC, respectively, as of December 31, 2019, and approximately a 57% and 43% split between OVEC and IKEC, respectively, as of December 31, 2018.

The Pension Plan’s assets as of December 31, 2019, consist of investments in equity and debt securities. All of the trust funds’ investments for the pension and postemployment benefit plans are diversified and managed in compliance with all laws and regulations. Management regularly reviews the actual asset allocation and periodically rebalances the investments to targeted allocation when appropriate. The investments are reported at fair value under the Fair Value Measurements and Disclosures accounting guidance.

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies, and target asset allocations by plan. Benefit plan assets are reviewed on a formal basis each quarter by the OVEC-IKEC Qualified Plan Trust Committee.

The investment philosophies for the benefit plans support the allocation of assets to minimize risks and optimize net returns.

Investment strategies include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs, and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style neutral to limit volatility compared to applicable benchmarks.

The target asset allocation for each portfolio is as follows:

Pension Plan Assets	**Target**
Domestic equity	15 %
International and global equity	15
Fixed income	68
Cash	2

VEBA Plan Assets	**Target**
Domestic equity	20 %
International and global equity	20
Fixed income	60

Each benefit plan contains various investment limitations. These limitations are described in the investment policy statement and detailed in customized investment guidelines. These investment guidelines require appropriate portfolio diversification and define security concentration limits. Each investment manager's portfolio is compared to an appropriate diversified benchmark index.

Equity investment limitations:

- No security in excess of 5% of all equities.

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- Cash equivalents must be less than 10% of each investment manager's equity portfolio.
- Individual securities must be less than 15% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

Fixed-Income Limitations—As of December 31, 2019, the Pension Plan fixed-income allocation consists of managed accounts composed of U.S. Government, corporate, and municipal obligations. The VEBA benefit plans' fixed-income allocation is composed of a variety of fixed-income securities and mutual funds. Investment limitations for these fixed-income funds are defined by manager prospectus.

Cash Limitations—Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments, including money market mutual funds, certificates of deposit, treasury bills, and other types of investment-grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

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Projected Pension Plan and Other Postretirement Benefits obligations and funded status as of December 31, 2019 and 2018, are as follows:

	Pension Plan		Other Postretirement Benefits	
	2019	2018	2019	2018
Change in projected benefit obligation:				
Projected benefit obligation—beginning of year	$ 234,099,137	$ 256,019,423	$ 151,305,246	$ 168,487,209
Service cost	6,078,450	7,108,309	3,428,368	4,297,973
Interest cost	10,082,144	9,445,262	6,571,166	6,196,344
Plan participants' contributions		-	1,312,941	1,363,566
Benefits paid	(8,079,496)	(10,240,977)	(6,795,047)	(5,270,543)
Net actuarial loss (gain)	30,255,836	(28,186,233)	21,462	(17,121,066)
Plan amendments (1) (2)		-	3,989,560	(6,648,237)
Settlement (3)	(27,857,703)	-	-	-
Expenses paid from assets	(36,469)	(46,647)	-	-
Projected benefit obligation—end of year	244,541,899	234,099,137	159,833,696	151,305,246
Change in fair value of plan assets:				
Fair value of plan assets—beginning of year	200,204,812	218,769,576	141,118,649	151,290,524
Actual return on plan assets	42,540,447	(14,277,140)	19,940,452	(6,304,997)
Expenses paid from assets	(36,469)	(46,647)	-	-
Employer contributions	5,600,000	6,000,000	13,853	40,099
Plan participants' contributions		-	1,312,941	1,363,566
Benefits paid	(8,079,496)	(10,240,977)	(6,795,047)	(5,270,543)
Settlement	(27,857,703)	-	-	-
Fair value of plan assets—end of year	212,371,591	200,204,812	155,590,848	141,118,649
Underfunded status—end of year	$ (32,170,308)	$ (33,894,325)	$ (4,242,848)	$ (10,186,597)

(1) The $3.9M plan amendment is the result of the change of the long-term retiree cost sharing through retiree contributions for pre-65 retirees from 20% to 12%.

(2) The $6.6M plan amendment is the result of the termination of the active/pre-65 retiree PPO and indemnity plans. All participants in those plans were moved to the CDHP.

(3) The $27.9M settlement is the result of an annuity purchase of about $22.7M for 162 retirees and beneficiaries which was paid on November 25, 2019 and the lump sums payments totaling about $5.2M during 2019.

See Note 1 for information regarding regulatory assets related to the Pension Plan and Other Postretirement Benefits plan.

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The accumulated benefit obligation for the Pension Plan was $218,590,886 and $212,367,000 at December 31, 2019 and 2018, respectively.

Components of Net Periodic Benefit Cost—The Companies record the expected cost of Other Postretirement Benefits over the service period during which such benefits are earned.

Pension expense is recognized as amounts are contributed to the Pension Plan and billed to customers. The accumulated difference between recorded pension expense and the yearly net periodic pension expense, as calculated under generally accepted accounting principles, is billable as a cost of operations under the ICPA when contributed to the pension fund. This accumulated difference has been recorded as a regulatory asset in the accompanying consolidated balance sheets.

	Pension Plan		Other Postretirement Benefits	
	2019	2018	2019	2018
Service cost	$ 6,078,450	$ 7,108,309	$ 3,428,368	$ 4,297,973
Interest cost	10,082,144	9,445,262	6,571,166	6,196,344
Expected return on plan assets	(11,867,776)	(13,034,239)	(7,515,431)	(8,062,728)
Amortization of prior service cost	(416,565)	(416,565)	(3,145,420)	(2,536,062)
Recognized actuarial loss (gain)	1,234,195	1,049,337	-	-
Cost of Settlements	3,570,924	-	-	-
Total benefit cost	$ 8,681,372	$ 4,152,104	$ (661,317)	$ (104,473)
Pension and other postretirement benefits expense recognized in the consolidated statements of income and retained earnings and billed to Sponsoring Companies under the ICPA	$ 5,600,000	$ 6,000,000	$ -	$ -

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The following table presents the classification of Pension Plan assets within the fair value hierarchy at December 31, 2019 and 2018:

	Fair Value Measurements at Reporting Date Using			
2019	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Common stock	$ 8,792,346	$ -	$ -	$ 8,792,346
Equity mutual funds	42,776,633	-	-	42,776,633
Index futures	-	230	-	230
Fixed-income securities	-	140,413,999	-	140,413,999
Commodities	-	43	-	43
Cash equivalents	7,154,484	-	-	7,154,484
Subtotal benefit plan assets	$ 58,723,463	$ 140,414,272	$ -	199,137,735
Investments measured at net asset value (NAV)				13,233,857
Total benefit plan assets				$ 212,371,592
2018	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Common stock	$ 7,138,880	$ -	$ -	$ 7,138,880
Equity mutual funds	35,494,238	-	-	35,494,238
Index futures	-	81	-	81
Fixed-income securities	-	142,452,199	-	142,452,199
Commodities	-	47	-	47
Cash equivalents	3,719,257	-	-	3,719,257
Subtotal benefit plan assets	$ 46,352,375	$ 142,452,327	$ -	188,804,702
Investments measured at net asset value (NAV)				11,400,110
Total benefit plan assets				$ 200,204,812

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The following table presents the classification of VEBA and 401(h) account assets within the fair value hierarchy at December 31, 2019 and 2018:

	Fair Value Measurements at Reporting Date Using			
2019	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**2019 Total**
Equity mutual funds	$ 54,952,087	$ -	$ -	$ 54,952,087
Fixed-income mutual funds	75,428,176	-	-	75,428,176
Fixed-income securities	-	21,122,393	-	21,122,393
Cash equivalents	1,175,475	-	-	1,175,475
Benefit plan assets	$ 131,555,738	$ 21,122,393	$	152,678,131
Uncleared cash disbursements from benefits paid				(5,468,253)
Investments measured at net asset value (NAV)				8,380,969
Total benefit plan assets				$ 155,590,847
2018	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Equity mutual funds	$ 46,690,283	$ -	$ -	$ 46,690,283
Fixed-income mutual funds	69,726,689	-	-	69,726,689
Fixed-income securities	-	19,673,412	-	19,673,412
Cash equivalents	1,866,335	-	-	1,866,335
Benefit plan assets	$ 118,283,307	$ 19,673,412	$ -	137,956,719
Uncleared cash disbursements from benefits paid				(3,866,878)
Investments measured at net asset value (NAV)				7,028,808
Total benefit plan assets				$ 141,118,649

Investments that were measured at net asset value (NAV) per share (or its equivalent) as a practical expedient have not been classified in the fair value hierarchy. These investments represent holdings in a single private investment fund that are redeemable at the election of the holder upon no more than 30 days' notice. The values reported above are based on information provided by the fund manager.

Pension Plan and Other Postretirement Benefit Assumptions—Actuarial assumptions used to determine benefit obligations at December 31, 2019 and 2018, were as follows:

	Pension Plan		Other Postretirement Benefits			
	2019	**2018**	**2019**		**2018**	
			Medical	**Life**	**Medical**	**Life**
Discount rate	3.58 %	4.40 %	3.55 %	3.55 %	4.40 %	4.40 %
Rate of compensation increase	3.00	3.00	N/A	3.00	N/A	3.00

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

Actuarial assumptions used to determine net periodic benefit cost for the years ended December 31, 2019 and 2018, were as follows:

	2019	2018	2019		2018	
			Medical	Life	Medical	Life
Discount rate	4.40 %	3.75 %	4.40 %	4.40 %	3.76 %	3.76 %
Expected long-term return on plan assets	6.00	6.00	5.33	6.00	5.33	6.00
Rate of compensation increase	3.00	3.00	N/A	3.00	N/A	3.00

In selecting the expected long-term rate of return on assets, the Companies considered the average rate of earnings expected on the funds invested to provide for plan benefits. This included considering the Pension Plan and VEBA trusts' asset allocation, and the expected returns likely to be earned over the life of the Pension Plan and the VEBAs.

Assumed health care cost trend rates at December 31, 2019 and 2018, were as follows:

	2019	2018
Health care trend rate assumed for next year—participants under 65	7.00 %	7.00 %
Health care trend rate assumed for next year—participants over 65	7.30	19.40
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)—participants under 65	5.00	5.00
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)—participants over 65	5.00	5.00
Year that the rate reaches the ultimate trend rate	2024	2024

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on total service and interest cost	$ 1,274,727	$ (1,043,944)
Effect on postretirement benefit obligation	19,856,817	(16,262,286)

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Pension Plan and Other Postretirement Benefit Assets—The asset allocation for the Pension Plan and VEBA trusts at December 31, 2019 and 2018, by asset category was as follows:

	Pension Plan		VEBA Trusts	
	2019	2018	2019	2018
Asset category:				
Equity securities	31 %	27 %	39 %	37 %
Debt securities	69	73	61	63

Pension Plan and Other Postretirement Benefit Contributions—The Companies expect to contribute $5,800,000 to their Pension Plan and $21,500 to their Other Postretirement Benefits plan in 2020.

Estimated Future Benefit Payments—The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Years Ending December 31	Pension Plan	Other Postretirement Benefits
2020	$ 9,176,543	$ 6,640,020
2021	9,826,112	7,064,850
2022	10,603,824	7,596,021
2023	11,268,181	8,175,889
2024	12,239,883	8,788,750
Five years thereafter	66,774,987	49,888,077

Postemployment Benefits—The Companies follow the accounting guidance in FASB ASC 712, *Compensation—Non-Retirement Postemployment Benefits*, and accrue the estimated cost of benefits provided to former or inactive employees after employment but before retirement. Such benefits include, but are not limited to, salary continuations, supplemental unemployment, severance, disability (including workers' compensation), job training, counseling, and continuation of benefits, such as health care and life insurance coverage. The cost of such benefits and related obligations has been allocated to OVEC and IKEC in the accompanying consolidated financial statements. The allocated amounts represent approximately a 42% and 58% split between OVEC and IKEC, respectively, as of December 31, 2019, and approximately a 59% and 41% split between OVEC and IKEC, respectively, as of December 31, 2018. The liability is offset with a corresponding regulatory asset and represents unrecognized postemployment benefits billable in the future to customers. The accrued cost of such benefits was $5,201,536 and $4,147,956 at December 31, 2019 and 2018, respectively.

Defined Contribution Plan—The Companies have a trustee-defined contribution supplemental pension and savings plan that includes 401(k) features and is available to

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employees who have met eligibility requirements. The Companies' contributions to the savings plan equal 100% of the first 1% and 50% of the next 5% of employee-participants' pay contributed. In addition, the Companies provide contributions to eligible employees, hired on or after January 1, 2015, of 3% to 5% of pay based on age and service. Benefits to participating employees are based solely upon amounts contributed to the participants' accounts and investment earnings. By its nature, the plan is fully funded at all times. The employer contributions for 2019 and 2018 were $1,966,847 and $2,014,215, respectively.

9. ENVIRONMENTAL MATTERS

Air Regulations

On March 10, 2005, the United States Environmental Protection Agency (the U.S. EPA) issued the Clean Air Interstate Rule (CAIR) that required significant reductions of SO_2 and NO_x emissions from coal-burning power plants. On March 15, 2005, the U.S. EPA also issued the Clean Air Mercury Rule (CAMR) that required significant mercury emission reductions for coal-burning power plants. These emission reductions were required in two phases: 2009 and 2015 for NO_x, 2010 and 2015 for SO_2, and 2010 and 2018 for mercury. Ohio and Indiana subsequently finalized their respective versions of CAIR and CAMR. In response, the Companies determined that it would be necessary to install flue gas desulfurization (FGD) systems at both plants to comply with these rules. Following completion of the necessary engineering and permitting, construction was started on the FGD systems, and the two Kyger Creek FGD systems were placed into service in 2011 and 2012, while the two Clifty Creek FGD systems were placed into service in 2013.

After the promulgation of CAIR and CAMR, a series of legal challenges to those rules resulted in their replacement with additional rules. CAMR was replaced with a rule referred to as the Mercury and Air Toxics Standards (MATS) rule. The rule became final on April 16, 2012, and the Companies had to demonstrate compliance with MATS emission limits on April 16, 2015. The MATS rule has also undergone legal challenges since it went into effect, and there are a few remaining legal issues pending. The controls the Companies have installed have proven to be adequate to meet the stringent emissions requirements outlined in the MATS rule.

After CAIR was promulgated, legal challenges resulted in that rule being remanded back to the U.S. EPA. The U.S. EPA subsequently promulgated a replacement rule to CAIR called the Cross-State Air Pollution Rule (CSAPR). CSAPR was issued on July 6, 2011, and it was scheduled to go into effect on January 1, 2012. However, a legal challenge of that rule resulted in a stay. The stay was lifted by the D.C. Circuit Court in 2014 and CSAPR, which requires significant NO_x and SO_2 emissions reductions, became effective on January 1, 2015. Further legal challenges of CSAPR resulted in the U.S. Supreme Court remanding portions of the CSAPR rule back to the D.C. Circuit Court for additional review and subsequent action by the U.S. EPA. This resulted in U.S. EPA issuing the CSAPR Update rule which became final on September 7, 2016, and went into effect beginning with the May 1, 2017 to September 30, 2017 ozone season. The CSAPR Update did not replace CSAPR, it only required additional reductions in NO_x emissions from utilities in twenty-two states (including Ohio and Indiana) during the ozone season. The Companies prepared for and implemented a successful compliance strategy for the CSAPR Update rule requirements in the 2017 ozone season. That strategy was standardized to meet future ozone season compliance obligations, and its execution provided for another successful ozone season in 2019. The CSAPR Update Rule has also been subject to extensive litigation, and the D.C. Circuit Court of Appeals issued a decision on September 13, 2019, on one of those legal challenges that remanded portions of this rule back to U.S. EPA to address. The EPA has not yet acted on the remand; however, the Companies are not currently anticipating any potential changes in the rule to address the D.C. Circuit Court remand that would materially impact our current compliance strategy or change future operations.

As a result of the installation and effective operation of the FGD systems and the SCR systems at each plant, management did not need to purchase additional annual SO_2 allowances, annual NO_x allowances or ozone season NO_x allowances in 2019 to cover actual emissions. The Companies also maintain a bank of allowances for all three programs as a hedge to cover future emissions in the event of any short-term operating events or other external factors. Depending on a variety of operational and economic factors, management may elect to consume a portion of these banked allowances and/or strategically purchase additional CSAPR annual and ozone season allowances in 2020 and beyond for compliance with the CSAPR and CSAPR Update rules.

With all FGD systems fully operational, the Companies continue to expect to have adequate SO_2 allowances available every year without having to rely on market purchases to comply with the CSAPR rules in their current form. Given the success of the Companies' NO_x ozone season compliance strategy, the purchase of additional NO_x allowances is less likely in the short term as well; however, the Companies did implement changes in unit dispatch criteria for Clifty Creek Unit 6 during the 2017 and subsequent ozone seasons and are continuing to evaluate the need for additional NO_x controls for this unit to provide additional flexibility in operating this unit in the event future NO_x regulations place additional emission constraints on the utility industry.

CCR Rule

In 2010, the U.S. EPA published a proposed rule to regulate the disposal and beneficial reuse of coal combustion residuals (CCRs), including fly ash and boiler slag generated at coal-fired electric generating units as well as FGD gypsum generated at some coal-fired plants. The proposed rule contained two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial reuse and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and existing unlined surface impoundments.

Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. To comply with a court-ordered deadline, the U.S. EPA issued a prepublication copy of its final rule in December 2014. The rule was published in the Federal Register in April 2015 and became effective in October 2015.

In the final rule, the U.S. EPA elected to regulate CCR as a nonhazardous solid waste and issued new minimum federal solid waste management standards. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes new and additional construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria, and additional groundwater monitoring requirements. The rule is self-implementing and currently does not require state action. As a result of this self-implementing feature, the rule contains extensive recordkeeping, notice, and Internet posting requirements.

The Companies have been systematically implementing the applicable provisions of the CCR rule. The Companies have completed all compliance obligations associated with the rule to date and are continuing to evaluate what, if any, impacts groundwater quality will have on the South Fly Ash Pond and landfill at Kyger Creek and the West Boiler Slag Pond and landfill at Clifty Creek. To date, these four CCR units continue to meet the groundwater monitoring standards of the CCR Rule. The Companies have been evaluating potential impacts to groundwater quality near the boiler slag pond at Kyger Creek and the landfill runoff collection pond at Clifty Creek as required by the CCR Rule. The Companies have determined that statistically significant increases (SSIs) in certain groundwater parameters are present at the two identified locations, and additional steps as defined by the CCR rule were taken. The evaluation of whether an SSI exists is a required component of the groundwater monitoring conditions of the CCR rule. A determination that an SSI appears to be present requires additional evaluation to be undertaken by the facility to determine if there are alternative sources that are influencing groundwater quality and to evaluate the extent of the groundwater quality impact. Concurrently, a facility must continue to evaluate groundwater quality as required by the CCR rule, and determine what potential corrective actions are feasible to address the SSIs. The Companies conducted Alternative Source Demonstrations (ASD) to determine if groundwater was being influenced from sources other than the CCR unit. The ASDs were unable to definitively prove that alternative sources were directly influencing groundwater quality. As a result, the Companies worked with their Qualified Professional Engineer (QPE) to determine what corrective actions were feasible for each CCR unit, and then held a public meeting to discuss these options with the public prior to selecting a remedy. The Companies continue to work through the compliance requirements of the CCR Rule and remain in compliance.

Since the initial rollout of the CCR rules in 2015, several legal, legislative and regulatory events impacting the scope, applicability and future CCR compliance obligations and timelines have also taken place. Final actions include federal legislation (i.e., the WIIN Act) that provides a pathway for states to seek approval for administering and enforcing the federal CCR program, U.S. EPA's issuance of a Phase I, Part I revision to the CCR rules on March 1, 2018, and the D.C. Circuit Court's August 21, 2018, ruling vacating and remanding portions of the CCR rule. In addition, the U.S. EPA announced plans to issue additional revisions to the CCR rule, some of which would also directly address the D.C. Circuit Court's issues raised in its August 21, 2018, decision. Other proposed revisions to the 2015 CCR rules that the U.S. EPA is currently undertaking will address outstanding issues previously identified by the agency and the Court. Two draft CCR rules entitled Part A and Part B, are in the public notice phase and are expected to be issued in final form later in 2020. Part A proposes a significant revision to the 2015 CCR rule requiring all impoundments that do not meet the liner requirements outlined in the 2015 CCR rule to cease receiving CCR material and initiate closure by August 31, 2020, regardless of their overall compliance status. If that date is not technically feasible, an alternate date to cease receiving CCR material and initiate closure can be secured from U.S. EPA through a proposed extension request process. The surface impoundments at Kyger Creek and Clifty Creek do not meet the liner design requirements required under the 2015 CCR rule. As a result, the Companies have begun an engineering evaluation to determine a technically feasible timeline for discontinuing placement of CCR materials in these impoundments and the initiation of closure consistent with the draft rule. Subsequently, the Companies intend to submit a technical justification document to U.S. EPA that demonstrates why additional time is needed to cease placement of CCR in the surface impoundments and initiate closure. The Companies anticipate U.S. EPA will approve the alternative schedule at this time. Separately, the proposed Part B revisions to the 2015 CCR rule outline the development of a federal permitting program to regulate and enforce the CCR rule at all applicable facilities consistent with the Congressional mandate outlined in the WIIN Act. This federal permit program would replace the current enforcement mechanism of a self-implementing rule enforced through citizen suits and place it back with U.S. EPA or any state regulatory that receives primacy to implement the CCR permitting within their respective state. The Companies are actively monitoring these developments and adapting their CCR compliance program to ensure compliance obligations and timelines are adjusted accordingly. Changes in regulations or in the Companies' strategies for mitigating the impact of coal combustion residuals could potentially result in material increases to the asset retirement obligations.

In February 2014, the U.S. EPA completed a risk evaluation of the beneficial uses of coal fly ash in concrete and FGD gypsum in wallboard and concluded that the U.S. EPA supports these beneficial uses. Currently, approximately 60 percent of the coal ash and other residual products from our generating facilities are reused in the production of cement and wallboard, as soil amendments, as abrasives or road treatment materials, and for other beneficial uses.

NAAQS Compliance for SO_2

On June 22, 2010, the U.S. EPA revised the Clean Air Act by developing and publishing a new one-hour SO_2 NAAQS of 75 parts per billion, which replaced the previously existing 24-hour and annual standards, and became effective on August 23, 2010. States with areas failing to meet the standard were required to develop state implemented plans to expeditiously attain and maintain the standard.

On August 15, 2013, the U.S. EPA published its initial non-attainment area designations for the new one-hour SO_2, which did not include the areas around Kyger Creek or Clifty Creek. However, the amended rule does establish that at a minimum, sources that emit 2,000 tons SO_2 or more per year be characterized by their respective states using either modeling of actual source emissions or through appropriately sited ambient air quality monitors.

In addition, U.S. EPA entered into a settle agreement with Sierra Club/NRDC in the U.S. District Court for the Northern District of California requiring U.S. EPA to take certain actions, including completing area designation by July 2, 2016, for areas with either monitored violations based on 2013-15 air quality monitoring or sources not announced for retirement that emitted more than 16,000 tons SO_2 or more than 2,600 tons with a 0.45 SO_2/mmBtu emission rate in 2012.

Both Kyger Creek and Clifty Creek directly or indirectly triggered one of the criteria and have been evaluated by the respective state regulatory agencies through modeling. The modeling results showed Clifty Creek could meet the new one-hour SO_2 limit using their current scrubber systems without any additional investment or modifications. Kyger Creek's modeling data was rejected by U.S. EPA as inconclusive in 2016. As a result, U.S. EPA required Kyger Creek install an SO_2 monitoring network around the plant and monitor ambient air quality beginning on January 1, 2017. Based on the first three years of data from that network, Ohio EPA will be preparing an updated petition to U.S. EPA requesting that the area in the county surrounding the plant be designated in attainment of the one-hour standard. Finally, on February 26, 2019, the U.S. EPA issued a final decision that it is retaining the existing primary SO_2 NAAQS at 75 parts per billion for the next five-year NAAQS review cycle. Given this decision, combined with current scrubber performance, the Companies expect to avoid more restrictive permit limits relative to its SO_2 emissions or the need for additional capital investment in major scrubber upgrades or modifications.

Steam Electric ELGs

On September 30, 2015, the U.S. EPA signed a new final rule governing Effluent Limitations Guidelines (ELGs) for the wastewater discharges from steam electric power generating plants. The rule, which was formally published in the Federal Register on November 3, 2015, impacted future wastewater discharges from both the Kyger Creek and Clifty Creek Stations.

The rule was intended to require the Companies to modify the way they handle a number of wastewater processes at both power plants. Specifically, the new ELG standards were going to affect the following wastewater processes in three ways listed below; however, in April 2017, the U.S. EPA issued an administrative stay on the ELG rule; and then in June 2017, the U.S. EPA issued a separate rulemaking staying the compliance deadlines for portions of the ELG rule applicable to bottom ash sluice water and to FGD wastewater discharges. The U.S. EPA has been working to revise the rule to evaluate what constitutes "best available technology" for these two wastewater discharges and issue an updated rule by no later than the fall of 2020. While the revised rule is not yet final, the Companies' understanding of what the original impacts and updated impacts to each wastewater discharge are highlighted below:

1. Kyger Creek will need to convert to dry fly ash handling by no later than December 31, 2023. The U.S. EPA stay on portions of the ELG rule does not impact the need to convert Kyger Creek Station to dry fly ash handling or the associated timeline. The Clifty Creek Station already has a dry fly ash handling system in place, so this provision of the rule will not impact Clifty Creek's operations.

2. The new ELG rules originally prohibited the discharge of bottom ash sluice water from boiler slag/bottom ash wastewater treatment systems. For Clifty Creek and Kyger Creek, this will likely result in the conversion of each plant's boiler slag pond to a closed-loop sluicing system for boiler slag. The Companies conducted a Phase I engineering study in 2016 to determine options and costs associated with retrofitting the plants' boiler slag treatment systems but postponed the study until more information was available from U.S. EPA on the technologies being considered in the revised rule. After reviewing the new draft rule, the Companies resumed the engineering study needed to formulate an

overall compliance strategy based on this updated information. This study includes a further evaluation of technologies or retrofits capable of complying with the requirements of the revised rule, which include preliminary engineering, design, and schedule development that were initiated late in 2019. The results of that evaluation are expected to be available in the second quarter of 2020.

3. The new ELG rules originally established new internal limitations for the FGD system wastewater discharges. Specifically, there were to be new internal limits for arsenic, mercury, selenium, and nitrate/nitrite nitrogen from the FGD chlorides purge stream wastewater treatment plant at each plant. For both Clifty Creek and Kyger Creek Stations, the Companies were expecting to be able to meet the mercury and arsenic limitations with the current wastewater treatment technology; however, the Companies were expecting to add some form of biological (or equivalent non-biological) treatment system on the back end of each Station's existing FGD wastewater treatment plant to meet the new nitrate/nitrite nitrogen and selenium limitations. Installation of new controls to meet the final effluent limitations contained in the revised rule are currently on hold while the Companies await further regulatory action from the U.S. EPA that will determine what the new limits for each of these constituents will be in the final ELG rule, which is expected late fall 2020. Once those final effluent limits are established, the Companies will resume evaluation of the appropriate technology, design, and schedule to achieve compliance with the new requirements. Based on the Companies' review of the draft revised ELG rule, the compliance deadline for FGD wastewater has been moved to compliance with the updated requirements no later than December 31, 2025.

Any new ELG limits will be implemented through each Station's wastewater discharge permit, which is typically renewed on a five-year basis. The final compliance dates are expected to be facility-specific and negotiated with the Companies' state permit agencies based on the time needed to plan, secure funding, design, procure, and install necessary control technologies once the new rulemaking has been completed. The Companies will continue to monitor EPA regulatory actions on this rule and will respond as necessary.

316(b) Compliance

The 316(b) rule was published as a final rule in the Federal Register on August 15, 2014, and impacts facilities that use cooling water intake structures designed to withdraw at least 2 million gallons per day from waters of the U.S., and those facilities who also have an NPDES permit. The rule requires such facilities choose one of seven options specified by the rule to reduce impingement to fish and other aquatic organisms. Additionally, facilities that withdraw 125 million gallons or more per day must conduct entrainment studies to assist state permitting authorities in determining what site-specific controls are required to reduce the number of aquatic organisms entrained by each respective cooling water system.

The Companies have completed the required two-year fish entrainment studies and filed the reports with the respective state regulatory agencies consistent with regulatory requirements under 40 CFR Section 122.21(r).

The timeline for determining if retrofits may be required to the cooling water systems at either Clifty Creek or Kyger Creek, as well as the type of retrofit required, will be negotiated with each state regulatory agency during future NPDES Permit renewals consistent with state regulatory obligations under 40 CFR Section 125.98(f).

The environmental rules and regulations discussed throughout the Environmental Matters footnote could require additional capital expenditures or maintenance expenses in future periods.

10. FAIR VALUE MEASUREMENTS

The accounting guidance for Financial Instruments requires disclosure of the fair value of certain financial instruments. The estimates of fair value under this guidance require the application of broad assumptions and estimates. Accordingly, any actual exchange of such financial instruments could occur at values significantly different from the amounts disclosed.

OVEC utilizes its trustee's external pricing service in its estimate of the fair value of the underlying investments held in the benefit plan trusts and investment portfolios. The Companies' management reviews and validates the prices utilized by the trustee to determine fair value. Equities and fixed-income securities are classified as Level 1 holdings if they are actively traded on exchanges. In addition, mutual funds are classified as Level 1 holdings because they are actively traded at quoted market prices. Certain fixed-income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed-income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed-income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, bids, offers, and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

As of December 31, 2019 and 2018, the Companies held certain assets that are required to be measured at fair value on a recurring basis. These consist of investments recorded within long-term investments. The investments consist of money market mutual funds, equity mutual funds, and fixed-income municipal securities. Changes in the observed trading prices and liquidity of money market funds are monitored as additional support for determining fair value, and unrealized gains and losses are recorded in earnings.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Companies believe their valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

As cash and cash equivalents, current receivables, current payables, and line of credit borrowings are all short-term in nature, their carrying amounts approximate fair value.

Long-Term Investments—Assets measured at fair value on a recurring basis at December 31, 2019 and 2018, were as follows:

	Fair Value Measurements at Reporting Date Using		
2019	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Equity mutual funds	$ 99,982,734	$ -	$ -
Fixed-income mutual funds	37,002,850	-	-
Fixed-income municipal securities		101,374,099	-
Cash equivalents	2,379,596	-	-
Total fair value	$139,365,180	$101,374,099	$ -
2018	**(Level 1)**	**(Level 2)**	**(Level 3)**
Equity mutual funds	$ 64,095,224	$ -	$ -
Fixed-income mutual funds	22,186,437	-	-
Fixed-income municipal securities	-	93,085,183	-
Cash equivalents	1,904,689	-	-
Total fair value	$ 88,186,350	$ 93,085,183	$ -

Long-Term Debt—The fair values of the senior notes and fixed-rate bonds were estimated using discounted cash flow analyses based on current incremental borrowing rates for similar types of borrowing arrangements. These fair values are not reflected in the balance sheets. The fair values and recorded values of the senior notes and fixed- and variable-rate bonds as of December 31, 2019 and 2018, are as follows:

	2019		**2018**	
	Fair Value	**Recorded Value**	**Fair Value**	**Recorded Value**
Total	1,390,779,759	1,275,148,664	1,398,244,690	1,329,819,085

11. LEASES

OVEC has various operating leases for the use of other property and equipment.

On January 1, 2019, the Companies adopted ASC 842, "Leases" which, among other changes, requires the Companies to record liabilities classified as operating leases on the balance sheet along with a corresponding right-of-use asset. Results for reporting periods beginning January 1, 2019, are presented under Topic 842, while prior period amounts are not adjusted and continue to be reported in accordance with historic accounting under Topic 840. The Companies elected the package of practical expedients available for expired or existing contracts, which allowed them to carryforward their historical assessments of whether contracts are or contain leases, lease classification tests and treatment of initial direct costs. Further, the Companies elected to not separate lease components from non-lease components for all fixed payments, and excluded variable lease payments in the measurement of right-of-use assets and lease obligations.

Upon adoption of ASC 842, the impact was a $22,000 increase in ROU assets and operating lease obligations. These adjustments are the result of assigning a right-of-use asset and related lease liability to the Companies operating leases. There were no cumulative effect adjustments to opening retained earnings, and adoption of the lease standard had no impact to cash from or used in operating, financing, or investing activities on the cash flow statement.

The Companies determine whether an arrangement is, or includes, a lease at contract inception. Leases with an initial term of 12 months or less are not recognized on the balance sheet. The Companies recognize lease expense for these leases on a straight-line basis over the lease term.

Operating lease right-of-use assets and liabilities are recognized at commencement date and initially measured based on the present value of lease payments over the defined lease term.

The leases typically do not provide an implicit rate; therefore, the Companies use the estimated incremental borrowing rate at the time of lease commencement to discount the present value of lease payments. In order to apply the incremental borrowing rate, a portfolio approach with a collateralized rate is utilized. Assets were grouped based on similar lease terms and economic environments in a manner whereby the Companies reasonably expect that the application is not expected to differ materially from a lease-by-lease approach.

The Companies have operating and finance leases for the use of vehicles, property, and equipment. The leases have remaining terms of 1 year to 7 years. The components of lease expense were as follows:

Year Ending December 31,	**2019**
Operating lease cost	$ 15,095
Finance lease cost:	
Amortization of leased assets	$ 258,411
Interest on lease liabilities	61,547
Total finance lease cost	$ 319,958

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

Supplemental cash flow information related to leases was as follows:

Operating cash flows from operating leases	$15,095
Operating cash from finance leases	55,793
Financing cash flows from finance leases	156,130
Weighted average remaining lease term:	
Operating leases	< 1 year
Finance leases	4 years
Weighted average discount rate:	
Operating leases	3.8 %
Finance leases	8.1 %

The amount of operating lease ROU assets and liabilities is $7,431 and $0 as of December 31, 2019 and 2018, respectively.

The amount in property under finance leases is $1,545,051 and $1,156,718 with accumulated depreciation of $669,164 and $464,194 as of December 31, 2019 and 2018, respectively.

Future cash flows of operating leases, and maturities of financing lease liabilities are as follows:

Years Ending December 31	Operating	Finance
2020	$ 7,512	$291,782
2021	-	221,997
2022	-	151,065
2023	-	89,223
2024	-	55,121
Thereafter	-	105,649
Total future minimum lease payments	$ 7,512	914,837
Less estimated interest element		168,135
Estimated present value of future minimum lease payments		$746,702

12. COMMITMENTS AND CONTINGENCIES

The Companies are party to or may be affected by various matters under litigation. Management believes that the ultimate outcome of these matters will not have a significant adverse effect on either the Companies' future results of operation or financial position.

On March 31, 2018, FirstEnergy Solutions Corp. (FES), one of the Sponsoring Companies under the ICPA, filed for Chapter 11 bankruptcy protection under the United States Bankruptcy Code in the United States Bankruptcy Court for the Northern District of Ohio (the "Bankruptcy Court"). OVEC made a preemptive filing on March 26, 2018, at the Federal Energy Regulatory Commission (FERC) requesting either (i) an order finding that FES's anticipated rejection of the ICPA would constitute a violation of that agreement's terms and would not satisfy the Federal Power Act's "public interest" standard, or, (ii) an order declaring that FERC has exclusive jurisdiction over the proposed rejection of the ICPA (the "FERC Action"). On April 1, 2018, FES filed in the Bankruptcy Court a motion to reject the ICPA and separately obtained an order temporarily enjoining the FERC Action. On May 11, 2018, the Bankruptcy Court granted a preliminary injunction enjoining FERC from reviewing FES's requested rejection of the ICPA under the public interest standard. FERC subsequently filed an appeal of this decision with the United States Court of Appeals for the Sixth Circuit (the "Injunction Appeal"), which OVEC joined as an intervenor. On July 31, 2018, the Bankruptcy Court granted FES's motion to reject the ICPA using the "business judgement" standard used to evaluate contract rejection under the Bankruptcy Code (the "Rejection Order"). Per the ICPA, upon rejection, OVEC made available to all other Sponsoring Companies FES's entitlement to available energy under the ICPA. OVEC appealed the Rejection Order to the Sixth Circuit (the "Rejection Appeal"). The Rejection Appeal was ultimately consolidated with the Injunction Appeal (together as consolidated, the "Sixth Circuit Rejection Appeal"). On December 12, 2019, the U.S. Court of Appeals for Sixth Circuit ruled on the Sixth Circuit Rejection Appeal by (1) affirming the Bankruptcy Court's jurisdiction over the rejection of the ICPA and (2) finding that the Bankruptcy Court should have considered the public interest in the standard for rejection and remanding to the Bankruptcy Court for further consideration under a heightened standard, after giving FERC a reasonable opportunity to weigh in. OVEC filed a petition for rehearing "en banc," and on March 13, 2020, the Sixth Circuit denied the petition.

On July 31, 2019, OVEC and FES entered into a stipulation with respect to OVEC's objection to confirmation of the FES plan of reorganization, stipulating that FES (a) would not seek to dismiss OVEC's Sixth Circuit appeal, or, if applicable, OVEC's appeal of an order with respect to an objection by OVEC to confirmation of the plan arising under section 1129(a)(6) of the Bankruptcy Code or oppose further review by the United States Supreme Court, on the grounds of mootness. OVEC objected to confirmation of the FES plan under section 1129(a)(6) of the Bankruptcy Code, which requires any governmental regulatory commission with jurisdiction, after confirmation of the plan, over the rates of a debtor to approve any rate change provided for in the plan, or that such rate change is expressly conditioned on such regulatory approval. OVEC's objection was overruled at the confirmation hearing on August 20th and 21st. The FES plan of reorganization was confirmed on October 16, 2019. On October 29, 2019, OVEC moved to certify a direct appeal of the Bankruptcy Court's confirmation order to the Sixth Circuit. On November 27, 2019, the Bankruptcy Court granted OVEC's motion to certify the confirmation order for direct appeal to the Sixth Circuit. On March 24, 2020, the Sixth Circuit granted OVEC's petition for direct appeal of the confirmation order.

On October 14, 2018, OVEC filed with the Bankruptcy Court its rejection damages claim of approximately $540 million against FES. The amount of OVEC's rejection damages claim has not been litigated at this time. Until the outcome of the Sixth Circuit Appeal and, potentially, a subsequent proceeding at FERC, it is undetermined whether FES will ultimately be permitted to reject its interest in the ICPA. FES's share of obligations, in each case under the ICPA, is approximately 5%. However, the Companies currently have access to the credit markets to fund ongoing liquidity needs, and the Sponsoring Companies remain obligated to fund debt service payments when due. The Companies accounts receivables as of December 31, 2019, on the consolidated balance sheets include receivables for FES's share of the Sponsor billings from March 2018 through December 31, 2019, which amounts to $38.5 million at December 31, 2019.

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OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of Ohio Valley Electric Corporation

We have audited the accompanying consolidated financial statements of Ohio Valley Electric Corporation and its subsidiary company, Indiana-Kentucky Electric Corporation (the "Companies"), which comprise the consolidated balance sheets as of December 31, 2019 and 2018, and the related consolidated statements of income and retained earnings and cash flows for the years then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Companies' preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Companies' internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Companies as of December 31, 2019 and 2018, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

/s/Deloitte & Touche LLP
Columbus, Ohio
April 17, 2020

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

OVEC PERFORMANCE – A 5-YEAR COMPARISON

	2019	2018	2017	2016	2015
Net Generation (MWh)	**11,238,298**	12,146,884	11,940,259	9,946,877	8,899,619
Energy Delivered (MWh) to:					
DOE	**125,881**	148,613	156,768	173,873	221,610
Sponsors	**11,234,353**	11,863,505	11,724,662	9,745,956	8,681,829
Maximum Scheduled (MW) by:					
DOE	**21**	33	34	35	40
Sponsors	**2,209**	2,173	2,186	2,167	2,047
Power Costs to:					
DOE	**$4,641,000**	$7,606,000	$8,188,000	$8,519,000	$10,249,000
Sponsors	**$640,801,000**	$644,114,000	$636,287,000	$571,687,000	$559,123,000
Average Price (MWh):					
DOE	**$36.869**	$51.180	$52.229	$48.996	$46.248
Sponsors	**$57.040**	$54.294	$54.270	$58.657	$64.402
Operating Revenues	**$614,667,000**	$615,839,000	$624,058,000	$585,896,000	$565,329,000
Operating Expenses	**$554,642,000**	$523,196,000	$560,170,000	$515,702,000	$492,803,000
Cost of Fuel Consumed	**$274,843,000**	$277,369,000	$288,503,000	$261,833,000	$246,582,000
Income and Other Taxes	**$8,418,000**	$12,165,000	$11,975,000	$12,329,000	$11,646,000
Payroll	**$55,491,000**	$57,569,000	$58,847,000	$60,051,000	$63,909,000
Fuel Burned (tons)	**5,111,144**	5,428,783	5,338,318	4,603,575	4,134,871
Heat Rate (Btu per kWh, net generation)	**10,714**	10,540	10,622	10,904	10,681
Unit Cost of Fuel Burned (per mmBtu)	**$2.28**	$2.17	$2.27	$2.41	$2.59
Equivalent Availability (percent)	**78.2**	76.6	75.6	72.9	64.7
Power Use Factor (percent)	**76.23**	84.19	83.90	72.67	73.07
Employees (year-end)	**591**	640	666	708	738

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Indiana Michigan Power Company
OVEC Billing Data
January 2015 to December 2020

	MWh	Energy Charge	Demand Charge	Transmission Charge	PJM Expenses/ Fees	Total Bill
Jan 2015	72,501	$1,899,272	$1,547,597	$109,246		$3,556,115
Feb	65,617	$1,720,027	$1,565,307	$105,027		$3,390,362
Mar	71,226	$1,899,161	$1,981,141	$107,897		$3,988,199
Apr	55,387	$1,490,052	$2,395,423	$101,130		$3,986,606
May	49,999	$1,505,223	$1,842,171	$91,925		$3,439,319
Jun	55,921	$1,654,843	$1,691,356	$100,677		$3,446,876
Jul	54,362	$1,651,366	$1,965,086	$100,085		$3,716,537
Aug	65,907	$1,787,529	$1,871,847	$104,923		$3,764,299
Sep	62,304	$1,820,109	$1,847,212	$101,736		$3,769,057
Oct	47,873	$1,392,335	$1,968,277	$98,916		$3,459,527
Nov	25,557	$811,597	$2,247,303	$89,352		$3,148,253
Dec	22,090	$779,366	$2,412,632	$88,226		$3,280,224

Indiana Michigan Power Company
Case No. U-20804
SC 4-1 Attachment 1

	MWh	Energy Charge	Demand Charge	Transmission Charge	PJM Expenses/ Fees	Total Bill
Jan 2016	52,558	$1,515,951	$1,531,039	$100,638		$3,147,628
Feb	44,281	$1,236,126	$1,617,773	$97,814		$2,951,713
Mar	29,756	$773,142	$1,892,817	$92,735		$2,758,695
Apr	32,278	$923,902	$2,567,807	$91,412		$3,583,121
May	48,478	$1,337,521	$1,986,197	$99,140		$3,422,858
Jun	80,535	$2,125,263	$1,524,541	$110,432		$3,760,236
Jul	88,148	$2,313,550	$1,712,436	$114,173		$4,140,159
Aug	84,446	$2,199,008	$1,796,092	$111,469		$4,106,569
Sep	84,528	$2,199,215	$1,683,785	$111,535		$3,994,535
Oct	46,778	$1,264,218	$2,203,944	$96,544		$3,564,706
Nov	60,683	$1,646,298	$2,151,153	$102,148		$3,899,599
Dec	91,108	$2,428,505	$2,415,220	$113,963		$4,957,689
Jan 2017	77,915	$1,958,792	$1,756,404	$109,355	$186	$3,824,737
Feb	83,113	$2,041,717	$1,925,768	$110,573	$784	$4,078,843
Mar	103,611	$2,516,284	$1,998,440	$118,002	$186	$4,632,911
Apr	66,155	$1,687,670	$2,442,300	$104,128	$186	$4,234,283
May	47,723	$1,254,953	$2,678,596	$96,421	$855	$4,030,825
Jun	78,688	$1,934,239	$1,808,936	$108,755	$186	$3,852,116
Jul	90,408	$2,146,206	$2,046,243	$113,290	$186	$4,305,923
Aug	86,215	$2,091,025	$1,939,160	$111,466	$831	$4,142,482
Sep	52,935	$1,318,937	$2,589,294	$98,536	$186	$4,006,953
Oct	65,446	$1,636,331	$2,561,559	$103,824	$186	$4,301,900
Nov	82,256	$2,003,463	$2,239,373	$110,684	$780	$4,354,300
Dec	103,155	$2,480,126	$2,007,877	$118,188	$186	$4,606,376
Jan 2018	94,970	$2,201,990	$1,828,115	$115,319	$190	$4,145,614
Feb	74,367	$1,891,001	$1,922,764	$106,826	$798	$3,921,390
Mar	92,426	$2,038,271	$2,108,377	$114,492	$190	$4,261,331
Apr	71,592	$1,588,687	$2,810,074	$106,423	$190	$4,505,375
May	56,548	$1,374,834	$2,748,094	$100,280	$806	$4,224,014
Jun	81,677	$1,887,062	$2,014,513	$110,091	$190	$4,011,855
Jul	92,665	$2,148,571	$2,203,312	$114,368	$190	$4,466,442
Aug	87,958	$2,060,939	$2,185,845	$112,573	$1,031	$4,360,388
Sep	68,432	$1,729,063	$2,187,940	$103,476	$417	$4,020,897
Oct	56,741	$1,276,276	$2,562,668	$99,449	$190	$3,938,583
Nov	91,032	$1,988,586	$1,962,812	$110,328	$990	$4,062,716
Dec	90,022	$2,228,542	$2,951,098	$95,791	$19,651	$5,295,083
Jan 2019	91,218	$2,152,952	$2,094,810	$110,194	-$1,915	$4,356,041
Feb	78,170	$1,836,187	$2,034,957	$105,126	$24,981	$4,001,251
Mar	87,236	$2,114,271	$2,344,018	$109,083	$13,497	$4,580,869
Apr	42,097	$1,136,458	$2,918,177	$92,291	$28,319	$4,175,244
May	60,874	$1,608,660	$2,570,080	$98,898	$24,129	$4,301,767
Jun	72,564	$1,792,517	$2,029,810	$103,577	$25,653	$3,951,558
Jul	90,014	$2,170,400	$2,170,947	$109,947	$23,149	$4,474,442
Aug	79,026	$2,008,555	$2,140,937	$105,945	$18,888	$4,274,325

	MWh	Energy Charge	Demand Charge	Transmission Charge	PJM Expenses/ Fees	Total Bill
Sep	72,769	$1,748,783	$2,286,598	$103,401	$50,137	$4,188,920
Oct	78,634	$1,935,855	$2,388,985	$106,183	$38,334	$4,469,357
Nov	89,736	$2,100,142	$1,884,349	$109,800	$10,588	$4,104,878
Dec	84,508	$2,070,091	$2,441,030	$108,224	$26,989	$4,646,333
Jan 2020	73,111	$1,774,282	$2,002,353	$103,859	$31,144	$3,911,638
Feb	64,814	$1,642,742	$1,939,210	$100,820	$33,116	$3,715,888
Mar	53,273	$1,423,887	$2,466,473	$96,633	$26,062	$4,013,055
Apr	30,105	$974,603	$2,635,093	$87,568	$28,325	$3,725,589
May	33,978	$978,732	$2,386,859	$88,915	-$251,480	$3,203,026
Jun	65,730	$1,609,964	$1,938,162	$102,441	$7,588	$3,658,155
Jul	73,949	$1,837,940	$2,150,072	$105,719	$10,518	$4,104,250
Aug	70,557	$1,715,507	$2,197,338	$104,073	-$1,852	$4,015,065
Sep	52,291	$1,396,224	$2,308,890	$96,881	$10,427	$3,812,422
Oct	45,990	$1,224,347	$2,547,592	$94,374	$13,366	$3,879,678
Nov	68,609	$1,712,394	$2,267,110	$103,728	$1,371	$4,084,602
Dec	89,069	$2,197,204	$3,231,200	$111,049	$2,250	$5,541,702

As reported by PJM

	Energy Revenues	Ancillary Revenue
May 2016	$302,747.14	$0.67
Jun 2016	$2,154,151.21	$197.18
Jul 2016	$2,831,350.89	$231.41
Aug 2016	$2,640,777.23	$660.77
Sep 2016	$2,503,461.16	$468.44
Oct 2016	$1,377,735.53	$315.99
Nov 2016	$1,571,913.99	$59.76
Dec 2016	$2,889,165.97	$95.79
Jan 2017	$2,292,946.82	$500.27
Feb 2017	$2,074,501.83	$173.26
Mar 2017	$3,180,843.68	$821.08
Apr 2017	$1,935,621.58	$258.61
May 2017	$1,430,521.24	$182.56
Jun 2017	$2,184,186.76	$78.73
Jul 2017	$2,758,507.76	$31.29
Aug 2017	$2,373,535.77	$76.60
Sep 2017	$1,679,230.03	$1,552.37
Oct 2017	$1,938,282.40	$11.48
Nov 2017	$2,385,552.74	$66.10
Dec 2017	$3,210,924.09	$0.00
Jan 2018	$4,634,744.00	$13,815.14
Feb 2018	$1,970,332.66	$0.00
Mar 2018	$2,913,590.64	$62.37
Apr 2018	$2,426,270.46	$36.73
May 2018	$1,932,982.46	$39,424.29
Jun 2018	$2,479,542.68	$86.76
Jul 2018	$2,939,188.57	$30.34
Aug 2018	$2,757,436.62	$13.76
Sep 2018	$2,393,559.71	$494.79
Oct 2018	$1,972,823.32	$2,422.64
Nov 2018	$3,322,595.26	$168.14
Dec 2018	$2,885,259.27	$2,145.26
Jan 2019	$2,827,876.77	$186.19
Feb 2019	$2,060,612.35	$2,450.76
Mar 2019	$2,555,122.32	$5,050.24
Apr 2019	$1,135,817.78	$3,003.12
May 2019	$1,547,838.64	$3,471.73
Jun 2019	$1,721,150.86	$2,779.52
Jul 2019	$2,509,929.46	$4,576.51
Aug 2019	$2,024,648.89	$3,166.37
Sep 2019	$1,984,088.21	$2,507.90
Oct 2019	$2,083,410.39	$6,595.46
Nov 2019	$2,622,153.22	$2,567.68
Dec 2019	$2,011,992.65	$1,011.62
Jan 2020	$1,657,028.64	$857.38
Feb 2020	$1,321,633.07	$720.01
Mar 2020	$968,761.98	$914.27
Apr 2020	$501,605.04	$153.25
May 2020	$635,743.61	$419.63
Jun 2020	$1,327,334.66	$3,762.91
Jul 2020	$1,911,109.59	$4,155.59
Aug 2020	$1,596,450.88	$4,539.38
Sep 2020	$1,108,804.20	$2,797.40
Oct 2020	$1,181,275.64	$10,272.84
Nov 2020	$1,471,473.69	$8,170.18
Dec 2020	$2,234,765.91	7,900.73

Q3

State of the Market Report for PJM

January through September

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

11.12.2020

2020

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Capacity Market

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1] The conclusions are a result of the MMU's evaluation of the last Base Residual Auction, for the 2021/2022 Delivery Year.

Table 5-1 The capacity market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Not Competitive	
Market Performance	**Not Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[2] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as not competitive in the 2021/2022 RPM Base Residual Auction. Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. But the net CONE times B offer cap under the capacity performance design, in the absence of 30 performance assessment hours, exceeds the competitive level and should be reevaluated for each BRA. In the 2021/2022 RPM Base Residual Auction, some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the nonperformance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.
- Market performance was evaluated as not competitive based on the 2021/2022 RPM Base Residual Auction. Although structural market power exists in the Capacity Market, a competitive outcome can result from the application of market power mitigation rules. The outcome of the 2021/2022 RPM Base Residual Auction was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, the inclusion of imports which are not substitutes for internal capacity resources, and the definition of the default offer cap.

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.
2 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test.
3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test.

- PJM did not run the 2022/2023 Base Residual Auction in May 2019, the 2023/2024 Base Residual Auction in May 2020, or the 2022/2023 First Incremental Auction in September 2020 because the capacity market design was found to be not just and reasonable by FERC and a final market design had not been approved.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[4]

Under RPM, capacity obligations are annual.[5] Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[6] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[7] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[8]

The 2020/2021 RPM Third Incremental Auction and the 2021/2022 RPM Second Incremental Auction were conducted in the first nine months of 2020.

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.[9] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** In the first nine months of 2020, RPM installed capacity decreased 788.7 MW or 0.4 percent, from 184,722.8 MW on January 1 to 183,934.17 MW on September 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on September 30, 2020, 45.7 percent was gas; 27.0 percent was coal; 17.6 percent was nuclear; 4.8 percent was hydroelectric; 3.4 percent was oil; 0.7 percent was wind; 0.4 percent was solid waste; and 0.5 percent was solar.
- **Market Concentration.** In the 2021/2022 RPM Second Incremental Auction, two participants in the EMAAC LDA market passed the TPS test.[10] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test,

4 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
5 Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either with commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.
6 See 126 FERC ¶ 61,275 at P 86 (2009).
7 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
8 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.
9 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.
10 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).

the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[11] [12] [13]

- **Imports and Exports.** Of the 4,470.4 MW of imports in the 2021/2022 RPM Base Residual Auction, 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (47.1 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,586.0 MW for June 1, 2020, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2020/2021 delivery year (13,015.2 MW) less purchases of replacement capacity (2,429.2 MW).

Market Conduct

- **2021/2022 RPM Second Incremental Auction.** Of the 276 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for zero generation resources (0.0 percent).

Market Performance

- The 2020/2021 RPM Third Incremental Auction and the 2021/2022 RPM Second Incremental Auction were conducted in the first nine months of 2020.[14] The weighted average capacity price for the 2019/2020 Delivery Year is $109.82 per MW-day, including all RPM auctions for the 2019/2020 Delivery Year. The weighted average capacity price for the 2020/2021 Delivery Year is $111.05 per MW-day, including all RPM auctions for the 2020/2021 Delivery Year.
- For the 2020/2021 Delivery Year, RPM annual charges to load are $7.0 billion.
- In the 2021/2022 RPM Base Residual Auction, the market performance was determined to be not competitive as a result of noncompetitive offers that affected market results.

Reliability Must Run Service

- Of the seven companies (23 units) that have provided RMR service, two companies (seven units) filed to be paid for RMR service under the deactivation avoidable cost rate (DACR), the formula rate. The other five companies (16 units) filed to be paid for RMR service under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd in the first nine months of 2020 was 6.3 percent, an increase from 6.0 percent in the first nine months of 2019.[15]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first nine months of 2020 was 86.8 percent, an increase from 85.2 percent in the first nine months of 2019.

Recommendations[16]

Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource

11 See OATT Attachment DD § 6.5.
12 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
13 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).
14 FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).
15 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on October 23, 2020. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.
16 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

types, including planned generation, demand resources and imports.[17] [18] (Priority: High. First reported 2013. Status: Not adopted.)

- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[19] [20] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be reviewed. (Priority: Medium. First reported 2019. Status: Not adopted.)

17 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
18 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
19 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
20 See the *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[21] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[22] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a process for calculating a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Market Seller Offer Cap (MSOC). The MMU recommends that the Nonperformance Charge Rate be left at its current level. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the MSOC. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed reserve margins, and other assumptions consistent with the annual IRM study. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit which is not capable of supplying energy consistent with its day-ahead offer which should equal its ICAP, reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance,

21 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).
22 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that RMR units recover all and only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules.

The MMU concludes that the 2021/2022 RPM Base Residual Auction results were not competitive as a result of offers above the competitive level by some market participants. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of net CONE times B. But net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the nonperformance charge rate is defined as net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

The FERC approved PJM tariff defines the offer cap as net CONE times B, rather than including the full logic supporting the definition of the offer cap under the capacity performance paradigm. If the tariff had defined the offer cap consistent with PJM's filing in the capacity performance matter, the offer cap would have been net ACR rather than net CONE times B.

The MMU filed a complaint with the Commission asserting that the market seller offer cap is overstated.[23] The result of an overstated market seller offer cap is to permit the exercise of market power, as occurred in the 2021/2022 BRA. That complaint remains pending. The outcome of the complaint could have a significant and standalone impact on clearing prices in the 2022/2023 BRA.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

The MMU found serious market structure issues, measured by the three pivotal supplier test results in the PJM Capacity Market in the last BRA and in the first nine months of 2020. Explicit market power mitigation rules in the RPM construct only partially offset the underlying market structure issues in the PJM Capacity Market under RPM. In the 2021/2022 RPM Base Residual Auction, the default offer cap of net CONE times B exceeded the competitive offer for a number of resources. Some seasonal resources were paid additional make whole based on a failure of the market power rules to apply offer capping.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[24] [25] [26] [27] [28] [29] In 2019 and 2020, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The capacity performance modifications to the RPM construct significantly improved the capacity market and addressed a number of issues that had been identified by the MMU. But significant issues remain in the PJM capacity market design.

The PJM markets have worked to provide incentives to entry and to retain capacity. PJM had excess reserves of 11,911.9 ICAP MW on June 1, 2020, and will have excess reserves of 18,401.8 ICAP MW on June 1, 2021, based on current positions.[30] A majority of capacity investments in PJM were financed by market sources.[31] Of the 41,979.4 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2019/2020 delivery years, 32,333.9 MW (77.0 percent) were based on market funding. Of the 2,640.4 MW of additional capacity that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years, 2,553.6 MW (96.7 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

The issue of external subsidies, particularly for economic nuclear power plants, continued to evolve. The subsidies are not part of the PJM market

23 In 2019, the MMU filed a complaint seeking an order directing PJM to update the assumptions regarding the expected number of performance assessment intervals (PAI) in calculating the default capacity market seller offer cap (MSOC). Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47-000 (February 21, 2019).

24 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).

25 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).

26 See "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

27 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

28 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

29 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

30 The calculated reserve margin for June 1, 2021, does not account for cleared buy bids that have not been used in replacement capacity transactions.

31 "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

design but nonetheless threaten the foundations of the PJM Capacity Market as well as the competitiveness of PJM markets overall.

The Ohio subsidy legislation to subsidize both nuclear and coal plants and to eliminate the RPS, the Illinois ZEC legislation to subsidize the Quad Cities nuclear power plant and the requests for additional subsidies, the request in Pennsylvania to subsidize nuclear power plants, the New Jersey legislation to subsidize the Salem and Hope Creek nuclear power plants, the potential U.S. DOE proposal to subsidize coal and nuclear power plants, the request by FirstEnergy to the U.S. DOE for subsidies consistent with the DOE Grid Resilience Proposal and the specific FRR proposals for ComEd and for New Jersey, all originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. The proposed solution in all cases ignores the opportunity cost of subsidizing uneconomic units, which is the displacement of new resources and technologies that would otherwise be economic. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market-based mechanisms available to all market participants on a competitive basis and without discrimination.

Subsidies are contagious. Competition in the markets could be replaced and is now being replaced by competition to receive subsidies. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these subsidies. Competition to receive subsidies is now a reality and is accelerating in PJM.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market. The MMU calls this approach the Sustainable Market Rule (SMR).[32] The SMR is fully consistent with the renewables targets of many states in the PJM footprint. The SMR is also consistent with incorporating economic nuclear power plants in the capacity market.

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet.

Subsidies to specific resources that are uneconomic as a result of competition are an effort to reverse market outcomes with no commitment to a regulatory model and no attempt to mitigate negative impacts on competition. The unit specific subsidy model is inconsistent with the PJM market design and inconsistent with the market paradigm and constitutes a significant threat to both.

The states have authority over their generation resources and can choose to remain in PJM capacity markets or to create FRR entities. The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. As made clear in recent analyses of FRR options in Illinois, Maryland, New Jersey and Ohio, the FRR approach is likely to lead to significant increases in payments by customers.[33] The existing FRR rules

32 The MMU filed several comments as well as a proposal summary in the Capacity Market Investigation focused on the Sustainable Market Rule (SMR) in Docket Nos. ER18-1314-000, -001, EL16-49-000, and EL18-178-000 (October 2, 2018; October 31, 2018; November 6, 2018). MMU filings are located at the Monitoring Analytics website at <http://www.monitoringanalytics.com/Filings/2018.shtml>.

33 The MMU has posted several reports regarding the creation of FRRs. "Potential Impacts of the Creation of a ComEd FRR," (December 18, 2019). <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf>. "Potential Impacts of the Creation of Maryland FRRs," (April 16, 2020). <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf>. "Potential Impacts of the Creation

were created in 2007 primarily for the specific circumstances of AEP as part of the original RPM capacity market design settlement. The FRR rules should be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market.

Recent FRR proposals in Illinois for the ComEd Zone and in New Jersey are primarily nuclear subsidy programs that would increase nuclear subsidies well beyond the ZECs rules currently in place in both states while also providing for payments to some renewable resources at above market prices.[34] The MMU has prepared reports with analysis on the potential impacts of states pursuing the FRR option. In separate reports for Illinois, Maryland, New Jersey and Ohio, the cost impacts of the state choosing the FRR option are computed under different FRR capacity price assumptions and different assumptions regarding the composition of the FRR service area.[35] [36] [37] [38] Additionally, the impact on the remaining PJM capacity market footprint is computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM capacity market would be significantly lower.

Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value is calculated correctly. PJM is considering the application of the Effective Load Carrying Capability (ELCC) approach to defining a dynamic and market based method for determining the capacity contribution of intermittent resources. ELCC would be an advance over the current approach to discounting the reliability contribution of intermittent resources, if done correctly. But implementing ELCC incorrectly, based on average rather than marginal values and locking in values regardless of market realities, would be a significant mistake and create new issues for the PJM capacity markets. The results could be degraded reliability, favoring old technologies over new technologies, and the inefficient displacement of thermal resources. It is essential to not build in a bad market design from the beginning as such designs gain momentum and gain entrenched supporters among the beneficiaries.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

Price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus in the entire market.

The expected impact of the SMR design on the offers and clearing of renewable resources and nuclear plants would be from zero to insignificant.

of New Jersey FRRs," (May 13, 2020). <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf>. "Potential Impacts of the Creation of Ohio FRRs," (July 17, 2020). <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf>.

34 *In the Matter of the Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities, Docket No. EO20030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf> (July 15, 2020).

35 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of a ComEd FRR," , <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf> (December 18, 2020).

36 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Maryland FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).

37 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of New Jersey FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf> (May 13, 2020).

38 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Ohio FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf> (July 17, 2020).

The competitive offers of renewables, based on the net ACR of current technologies, are likely to clear in the capacity market. The competitive offers of nuclear plants, based on net ACR, are likely to clear in the capacity market.

Cost of service resources have the option of using the existing FRR rules, which would allow regulated utilities to opt out of the capacity market. The expected impact of the SMR design on the offers and clearing of regulated cost of service resources that remained in the capacity market would be from zero to insignificant. The competitive offers of these resources, based on net ACR, are likely to clear in the capacity market.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed, but this can happen with a slightly longer lead time. If a shared goal is to reduce carbon output, a price on carbon is the market based solution. If a shared goal is increased renewables in addition to their carbon attributes, a common approach to RECs would be a market based solution. Fuel diversity has also been mentioned as an issue. Current fuel diversity is higher than ever in PJM. If there is an issue, the real issue is fuel security and not fuel diversity. Significant reliance on specific fuels, including nuclear, coal and gas means that markets are at risk from a significant disruption in any one fuel. If fuel security for gas is a concern, a number of issues should be considered including the reliability of the pipelines, the compatibility of the gas pipeline and the merchant generator business models, the degree to which electric generators have truly firm gas service and the need for a gas RTO/ISO to help ensure reliability.

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.[39]

The Commission issued its MOPR order on December 19, 2019 ("December 19th Order").[40] The December 19th Order defines a clear path for defending competitive wholesale power markets in PJM. The Order defines a clear, consistent and comprehensive approach to the PJM markets and to the role of subsidized resources in the markets. The 2022/2023 BRA is expected to be run by mid 2021.[41]

In another proceeding, the Commission has ordered PJM on compliance to propose revisions to the PJM market rules to implement a forward looking EAS offset to include forward looking energy and ancillary services revenues rather than historical.[42] The MMU has recommended such an approach. The change in the offset will affect MOPR floor prices and the results of unit specific reviews under MOPR. PJM submitted its compliance filing on August 5, 2020, and the matter is now pending.

39 See Monitoring Analytics, LLC, "Analysis of the 2021/2022 RPM Base Residual Auction – Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2008).

40 169 FERC ¶ 61,239.

41 Docket Nos. ER18-1314-000, -001, EL16-49-000, and EL18-178-000 (March 18, 2020 and June 1, 2020).

42 171 FERC ¶ 61,153 at PP 320–321 (2020).

Table 5-2 RPM related MMU reports: 2019 through 2020

Date	Name
February 21, 2019	IMM Complaint re CONE x B Offers Docket No. EL19-47-000 http://www.monitoringanalytics.com/Filings/2019/IMM_Complaint_Docket_No_EL19-XXX_20190221.pdf
February 22, 2019	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20190222.pdf
April 2, 2019	IMM Comments re ACR Review Waiver Docket No. ER19-1404 http://www.monitoringanalytics.com/Filings/2019/IMM_Comments_Docket_No_ER19-1404_20190402.pdf
April 10, 2019	IMM Answer and Motion for Leave to Answer re Cube Yadkin Complaint Docket No. EL19-51 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket_No_EL19-51_20190410.pdf
April 11, 2019	IMM Answer re Brookfield Energy Complaint Docket No. EL19-34 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket%20No.%20EL19-34_20190411.pdf
April 30, 2019	IMM Answer Re CONE x B Offers Docket No. EL19-47 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket_No_EL19-47_20190430.pdf
May 24, 2019	IMM Answer to PJM re MSOC Docket No. EL19-47, EL19-63 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_to_PJM_EL19-47_-63_20190524.pdf
June 28, 2019	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20190628.pdf
August 23, 2019	IMM Answer re Capacity Resources and Must Offer Exception Process Docket No. ER19-2417 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket_No_ER19-2417_20190823.pdf
September 6, 2019	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligations_20190906.pdf
September 12, 2019	PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Reports/2019/IMM_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_Delivery_Years_20190912.pdf
September 13, 2019	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019 http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf
September 17, 2019	IMM Response to Grid Strategies Report http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Response_to_Grid_Strategies_Report_201909217.pdf
December 13, 2019	IMM Comments re Performance Assessment Intervals Docket No. EL19-47-000 http://www.monitoringanalytics.com/Filings/2019/IMM_Comments_Docket_No_ER15-623_EL15-29_EL19-47_20191213.pdf
December 18, 2019	Potential Impacts of the Creation of a ComEd FRR http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf
December 26, 2019	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligations_20191226.pdf
January 16, 2020	Net Revenues for PJM RPM Base Residual Auctions in 2020 http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Net_Revenues_20232024_RPM_BRA_20200116.pdf
January 17, 2020	IMM Request for Clarification re MOPR Order Docket Nos. EL16-49 and EL18-178 http://www.monitoringanalytics.com/filings/2020/IMM_Request_for_Clarification_Docket_Nos_EL16-49_EL18-178_20200117.pdf
January 21, 2020	CONE and ACR Values - Preliminary http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_Special_Special_Session_CONE_and_ACR_Values_20200128.pdf
February 5, 2020	IMM Answer to Requests for Rehearing's Docket No. EL14-69 and EL18-178 http://www.monitoringanalytics.com/filings/2020/IMM_Answer_To_RFRS_Docket_Nos_EL14-69_EL18-178_20200205.pdf
February 17, 2020	IMM MOPR Gross CONE Template http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MOPR_Gross_CONE_Template_20200217.xlsx
February 18, 2020	IMM Second Request for Clarification re MOPR Docket No. EL18-178, EL16-49 http://www.monitoringanalytics.com/filings/2020/IMM_Second_Request_for_Clarification_Docket_No_EL18-178_%20EL16-49_20200218.pdf
February 18, 2020	Unit Specific Nuclear ACR Information http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_MOPR_Unit_Specific_Nuclear_ACR_Information_20200219.pdf
February 21, 2020	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_RPM_Must_Offer_Obligations_20200221.pdf
February 28, 2020	Monitoring Analytics ACR Template http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_Special_Session_ACR_Template_20200228.pdf
March 20, 2020	Potential Impacts of the MOPR Order http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_MOPR_Order_20200320.pdf
April 16, 2020	Potential Impacts of the Creation of Maryland FRRs http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf
May 6, 2020	Potential Compliance with P386 of FERC Order on Rehearing http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_Special_Session_Potential_Compliance_with_P386_of_FERC_Order_on_Rehearing_20200506.pdf
May 13, 2020	Potential Impacts of the Creation of New Jersey FRRs http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf
May 15, 2020	IMM Request for Clarification re MOPR Ex Investigation Docket Nos. EL18-178-002 and EL16-49-002 http://www.monitoringanalytics.com/filings/2020/IMM_Request_for_Clarification_Docket_No_EL18-178-002_EL16-49-002_20200515.pdf
May 15, 2020	IMM Comments re MOPR-Ex Docket Nos. ER18-1314-00, EL16-49-000, EL18-178-000 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER18-1314-003_EL16-49_EL18-178_20200515.pdf
May 20, 2020	IMM Comments re NJBPU Investigation of Resource Adequacy Alternatives Docket No. EO20030203 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf
June 22, 2020	IMM Comments re MOPR-Ex Compliance Filing Docket Nos. ER18-1314, EL16-49 and ERL8-178 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER18-1314_EL16-49_ER18-178_20200622.pdf
June 24, 2020	IMM Reply Comments re NJ BPU Resource Adequacy Alternatives Docket No. EO20030203 http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf
June 30, 2020	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_RPM_Must_Offer_Obligations_20200630.pdf
July 15, 2020	IMM Answer to PSEG and Exelon Reply re New Jersey FRR Docket No. EO20030203 http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf
July 17, 2020	Potential Impacts of the Creation of Ohio FRRs http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf
July 20, 2020	IMM Comments re NJ BPU Nuclear Power Plant ZECs Docket No. EO18080899 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO18080899_20200720.pdf
July 23, 2020	IMM Answer re MOPR Ex Docket No. EL16-49, ER18-1314 and EL18-178 http://www.monitoringanalytics.com/filings/2020/IMM_Answer_Docket_No_EL16-49_ER18-1314_EL18-178_20200724.pdf
July 27, 2020	IMM Comments re ORDC Compliance Filing Docket No. EL19-58-002 and ER19-1486 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_EL19-58-002_ER19-1486-20200727.pdf
September 15, 2020	2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022 http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf

Installed Capacity

On January 1, 2020, RPM installed capacity was 184,722.8 MW (Table 5-3).[43] Over the next nine months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 183,934.1 MW on September 30, 2020, a decrease of 788.7 MW or 0.4 percent from the January 1 level.[44] [45] The 788.7 MW decrease was the result of a decrease in imports (582.9 MW), an increase in exports (328.9 MW), derates (81.4 MW), and deactivations (2,456.1 MW), offset by new or reactivated generation (2,233.1 MW) and uprates (427.5 MW).

At the beginning of the new delivery year on June 1, 2020, RPM installed capacity was 184,583.3 MW, a decrease of 1,069.2 MW or 0.6 percent from the May 31, 2020, level of 185,652.5 MW.

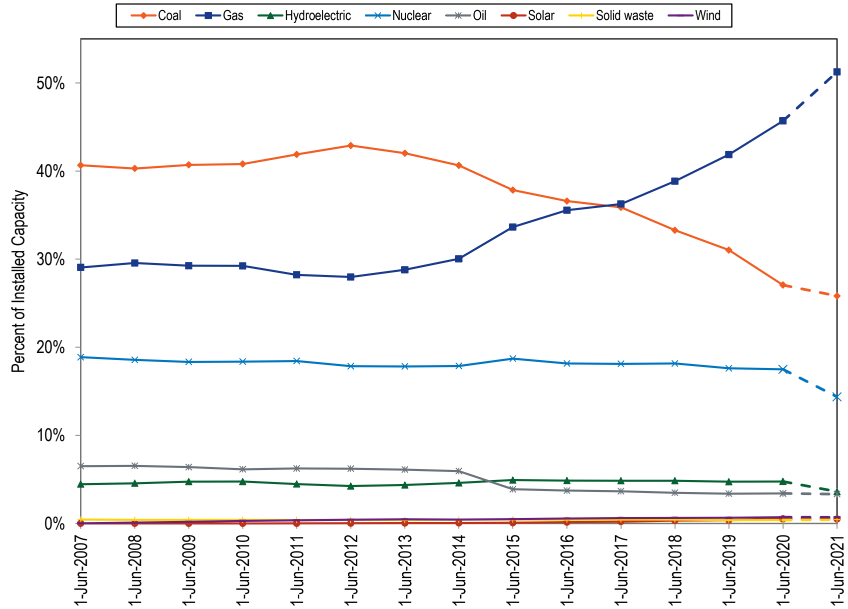
Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and September 30, 2020

	01-Jan-20		31-May-20		01-Jun-20		30-Sep-20	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	52,181.3	28.2%	51,281.6	27.6%	49,942.4	27.1%	49,649.9	27.0%
Gas	82,313.9	44.6%	84,195.7	45.4%	84,355.1	45.7%	83,971.4	45.7%
Hydroelectric	8,873.9	4.8%	8,862.2	4.8%	8,778.7	4.8%	8,779.3	4.8%
Nuclear	32,297.9	17.5%	32,285.4	17.4%	32,285.4	17.5%	32,285.4	17.6%
Oil	6,311.0	3.4%	6,282.8	3.4%	6,282.8	3.4%	6,282.8	3.4%
Solar	791.0	0.4%	791.0	0.4%	946.9	0.5%	960.3	0.5%
Solid waste	695.6	0.4%	695.6	0.4%	695.6	0.4%	695.6	0.4%
Wind	1,258.2	0.7%	1,258.2	0.7%	1,296.4	0.7%	1,309.4	0.7%
Total	184,722.8	100.0%	185,652.5	100.0%	184,583.3	100.0%	183,934.1	100.0%

43 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.
44 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the Capacity Exchange system, regardless of whether the capacity cleared in the RPM auctions.
45 Wind resources accounted for 1,309.4 MW, and solar resources accounted for 960.3 MW of installed capacity in PJM on September 30, 2020. PJM administratively reduces the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind and solar resources will be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Appendix B.3 Calculation Procedure, Rev. 14 (Aug. 1, 2019).

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2020, as well as the expected installed capacity for the 2021/2022 delivery year, based on the results of all auctions held through September 30, 2020.[46] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 27.1 percent on June 1, 2020, and is projected to decrease to 25.8 percent by June 1, 2021. The share of gas increased from 29.1 percent on June 1, 2007, to 45.7 percent on June 1, 2020, and is projected to increase to 51.3 percent on June 1, 2021.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2021



46 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Table 5-4 shows the RPM installed capacity on January 1, 2020, through September 30, 2020, for the top five generation capacity resource owners, excluding FRR committed MW.

Table 5-4 Installed capacity by parent company: January 1, May 31, June 1, and September 30, 2020

	01-Jan-20			31-May-20			01-Jun-20			30-Sep-20		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Exelon Corporation	21,165.8	12.4%	1	21,041.9	12.3%	1	20,801.8	12.1%	1	20,788.8	12.2%	1
Dominion Resources, Inc.	20,198.5	11.8%	2	20,198.5	11.8%	2	20,549.9	12.0%	2	20,525.1	12.0%	2
FirstEnergy Corp.	11,609.3	6.8%	3	4,102.5	2.4%	12	4,100.6	2.4%	12	4,100.6	2.4%	12
Vistra Energy Corp.	11,451.0	6.7%	4	11,290.9	6.6%	3	11,319.0	6.6%	3	11,319.0	6.6%	3
Talen Energy Corporation	10,964.6	6.4%	5	10,964.6	6.4%	4	10,839.4	6.3%	4	10,839.4	6.4%	4
LS Power Group	7,839.5	4.6%	7	8,709.5	5.1%	5	8,862.5	5.2%	5	8,841.8	5.2%	5

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2020, to September 30, 2020, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and September 30, 2020

	01-Jan-20		31-May-20		01-Jun-20		30-Sep-20	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	152,177.4	82.4%	153,111.1	82.5%	151,765.2	82.2%	151,140.8	82.2%
Nonmarket	32,545.4	17.6%	32,541.4	17.5%	32,818.1	17.8%	32,793.3	17.8%
Total	184,722.8	100.0%	185,652.5	100.0%	184,583.3	100.0%	183,934.1	100.0%

Fuel Diversity

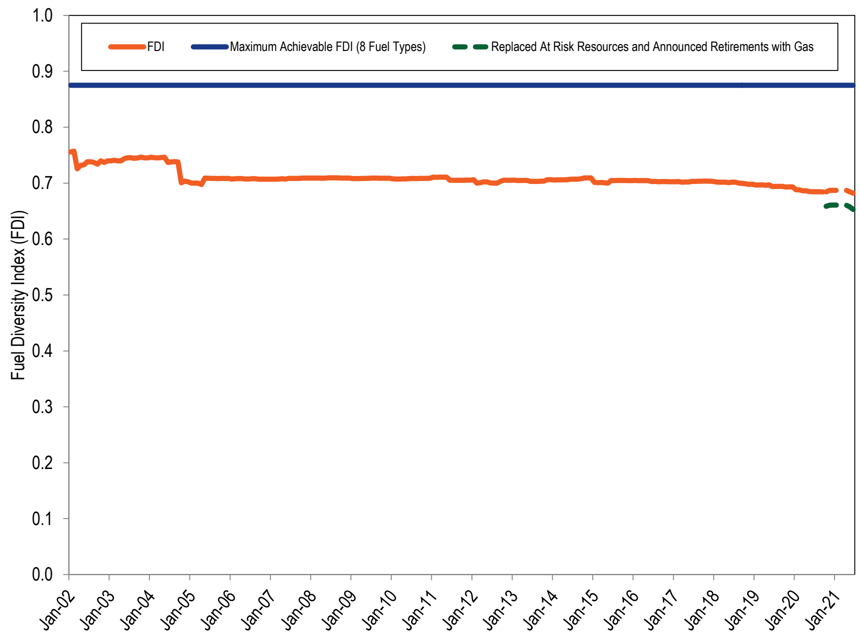
Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[47] The FDI_c is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type i. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. The fuel type categories used in the calculation of the FDI_c are the eight fuel sources in Table 5-3. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[48] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004 with the expansion into the ComEd, AEP, and Dayton Power & Light Control Zones.[49] The average FDI_c for the first nine months of 2020 decreased 1.4 percent compared to the first nine months of 2019. Figure 5-2 also includes the expected FDI_c through June 2021 based on cleared RPM auctions. The expected FDI_c is indicated in Figure 5-2 by the dashed orange line.

The FDI_c was used to measure the impact of potential retirements of resources that the MMU has identified as being at risk of retirement. A total of 9,543.0 MW of coal, diesel, and nuclear capacity were identified as being at risk of retirement.[50] Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance of the retirement.[51] There are 4,556.0 MW of generation that have a requested retirement date

47 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.
48 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 State of the Market Report for PJM* for additional details.
49 See the *2019 State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.
50 See the *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.
51 See OATT Part V § 113.1.

after September 30, 2020.[52] The dashed green line in Figure 5-2 shows the FDI_c calculated assuming that the capacity that cleared in an RPM auction from the at risk resources and other resources with deactivation notices is replaced by gas generation.[53] The FDI_c under these assumptions would decrease by 3.9 percent on average from the expected FDI_c for the period October 1, 2020, through June 1, 2021.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 1, 2021



52 See *2020 Quarterly State of the Market Report for PJM: January through September*, Section 12: Generation and Transmission Planning, Table 12-9.

53 For this analysis resources for which PJM has received deactivation notifications were replaced with gas capacity beginning on the projected retirement date listed in the deactivation data. At risk resources that have not notified PJM regarding deactivation were replaced with gas capacity beginning on October 1, 2020.

RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[54] In the first nine months of 2020, the 2020/2021 RPM Third Incremental Auction and the 2021/2022 RPM Second Incremental Auction were conducted.[55]

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2019/2020 Delivery Year. The 21,993.1 MW increase was the result of new generation capacity resources (33,614.4 MW), reactivated generation capacity resources (1,362.8 MW), uprates (7,002.2 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (1,905.2 MW), offset by a net decrease in capacity imports (1,013.6 MW), deactivations (39,400.0 MW) and derates (3,445.4 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) for June 1, 2016, through June 1, 2021, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the most recent peak load forecast for each delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction

54 See Letter Order, Docket No. ER10-366-000 (January 22, 2010).

55 FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

using the cleared buy bid capacity. Without an approved early replacement transaction requested for defined physical reasons, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. The calculated reserve margins for June 1, 2021, does not account for cleared buy bids that have not been used in replacement capacity transactions. The projected reserve margin for June 1, 2021, accounts for projected replacement capacity using cleared buy bids by applying the rate at which historical buy bids have been used.

Future Changes in Generation Capacity[56]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2019/2020 Delivery Year, internal installed capacity decreased by 866.0 MW after accounting for new capacity resources, reactivations, and uprates (41,979.4 MW) and capacity deactivations and derates (42,845.4 MW).

For the current and future delivery years (2020/2021 through 2021/2022), new generation capacity is defined as capacity that cleared an RPM auction for the first time in the specified delivery year. Based on expected completion rates of cleared new generation capacity (2,640.4MW) and pending deactivations (3,464.7MW), PJM capacity is expected to decrease by 824.3 MW for the 2020/2021 through 2021/2022 Delivery Years.

Table 5-6 Generation capacity changes: 2007/2008 through 2019/2020[57 58]

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	84.0	5,536.0	317.8	(3,201.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	28.9	2,786.9	288.3	1,205.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
2019/2020	4,612.0	13.3	494.9	165.0	(1,196.6)	401.3	3,296.0	116.8	274.5
Total	33,614.4	1,362.8	7,002.2	21,967.5	(1,013.6)	(1,905.2)	39,400.0	3,445.4	21,993.1

56 For more details on future changes in generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).
57 The capacity changes in this report are calculated based on June 1 through May 31.
58 The calculated export MW for 2012/2013 were revised from the *2020 Quarterly State of the Market Report for PJM: January through March.*

Table 5-7 RPM reserve margin: June 1, 2016, to June 1, 2021[59] [60]

	Generation and DR RPM Committed Less Deficiency UCAP (MW)	Forecast Peak Load	FRR Peak Load	PRD	RPM Peak Load	IRM	Pool Wide Average EFORd	Generation and DR RPM Committed Less Deficiency ICAP (MW)	Reserve Margin	Reserve Margin in Excess of IRM		Projected Replacement Capacity using Cleared Buy Bids UCAP (MW)	Projected Reserve Margin
										Percent	ICAP (MW)		
01-Jun-16	160,883.3	152,356.6	12,511.6	0.0	139,845.0	16.4%	5.91%	170,988.7	22.3%	5.9%	8,209.2	0.0	22.3%
01-Jun-17	163,872.0	153,230.1	12,837.5	0.0	140,392.6	16.6%	5.94%	174,220.7	24.1%	7.5%	10,522.9	0.0	24.1%
01-Jun-18	161,242.6	152,407.9	12,732.9	0.0	139,675.0	16.1%	6.07%	171,662.5	22.9%	6.8%	9,499.8	0.0	22.9%
01-Jun-19	162,276.1	151,643.5	12,284.2	0.0	139,359.3	16.0%	6.08%	172,781.2	24.0%	8.0%	11,124.4	0.0	24.0%
01-Jun-20	159,560.4	148,355.3	11,488.3	558.0	136,309.0	15.5%	5.78%	169,348.8	24.2%	8.7%	11,911.9	0.0	24.2%
01-Jun-21	164,773.5	147,501.6	11,394.3	510.0	135,597.3	15.1%	5.56%	174,474.3	28.7%	13.6%	18,401.8	7,325.0	23.0%

Sources of Funding[61]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New and reactivated generation capacity from the 2007/2008 Delivery Year through the 2019/2020 Delivery Year totaled 34,977.2 MW (83.3 percent of all additions), with 26,796.1 MW from market funding and 8,181.1 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 Delivery Year through the 2019/2020 Delivery Year totaled 7,002.2 MW (16.7 percent of all additions), with 5,537.8 MW from market funding and 1,464.4 MW from nonmarket funding. In summary, of the 41,979.4 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2019/2020 Delivery Years, 32,333.9 MW (77.0 percent) were based on market funding.

Of the 2,640.4 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years, 2,214.9 MW are not yet in service. Of those 2,214.9 MW that have not yet gone into service, 2,195.9 MW have market funding and 19.0 MW have nonmarket funding. Applying the historical completion rates, 73.1 percent of all the projects in development are expected to go into service (1,604.1 MW of the 2,195.9 MW of market funded projects; 13.9 MW of the 19.0 MW of nonmarket funded projects). Together, 1,618.0 MW of the 2,214.9 MW of new generation capacity that cleared MW in RPM and are not yet in service are expected to go into service through the 2021/2022 Delivery Year.

Of the 425.5 MW of the additional generation capacity that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years and are already in service, 357.7 MW (84.1 percent) are based on market funding and 67.8 MW (15.9 percent) are based on nonmarket funding. In summary, 2,553.6 MW (96.7 percent) of the additional generation capacity (425.5 MW in service and 2,214.9 MW not yet in service) that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years are based on market funding. Capacity additions based on nonmarket funding are 86.8 MW (3.3 percent) of proposed generation that cleared at least one RPM auction for the 2020/2021 through 2021/2022 Delivery Years.

59 The calculated reserve margins in this table do not include EE on the supply side or the EE add back on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.
60 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.
61 For more details on sources of funding for generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

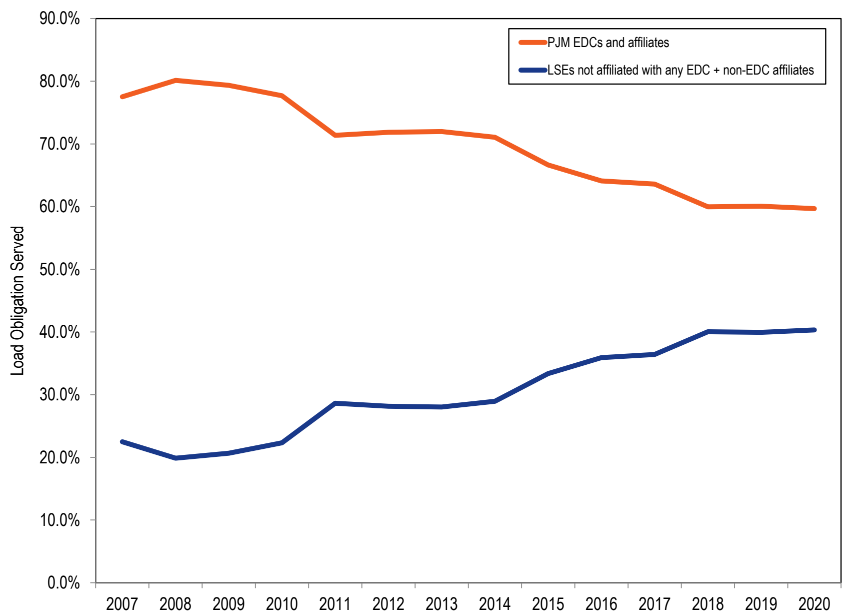
- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2020, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 59.7 percent (Table 5-8), down from 60.1 percent on June 1, 2019. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 40.3 percent, up from 39.9 percent on June 1, 2019. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007, to June 1, 2020, is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 59.7 percent on June 1, 2020. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 40.3 percent on June 1, 2020. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Table 5-8 Capacity market load obligation served: June 1, 2019 and June 1, 2020

	1-Jun-19		1-Jun-20		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	113,416.3	60.1%	104,849.4	59.7%	(8,566.8)	(0.4%)
LSEs not affiliated with any EDC + non EDC Affiliates	75,445.0	39.9%	70,838.3	40.3%	(4,606.7)	0.4%
Total	188,861.3	100.0%	175,687.7	100.0%	(13,173.6)	0.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2020



Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays for the transmission system through firm transmission charges and pays congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. CTRs permit customers to receive the benefit of importing cheaper capacity using transmission capability. The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, based on the results of the Base Residual Auction and Incremental Auctions, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction, and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights Eligible Required Transmission Enhancements.

For LDAs in which the RPM auctions for a delivery year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment or charge equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs.

In the 2021/2022 RPM Base Residual Auction, EMAAC had 4,352.6 MW of CTRs with a total value of $40,877,295, PSEG had 4,990.5 MW of CTRs with a total value of $70,238,159, ATSI had 6,402.8 MW of CTRs with a total value of $73,219,252, ComEd had 1,527.9 MW of CTRs with a total value of $30,978,820, and BGE had 5,125.6 MW of CTRs with a total value of $112,812,971.

EMAAC had 40.0 MW of customer funded ICTRs with a total value of $375,658, PSEG had 41.0 MW of customer funded ICTRs with a total value of $577,050, BGE had 65.7 MW of customer funded ICTRs with a total value of $1,446,024, and ComEd had 1,097.0 MW of customer funded ICTRs with a total value of $22,242,498.

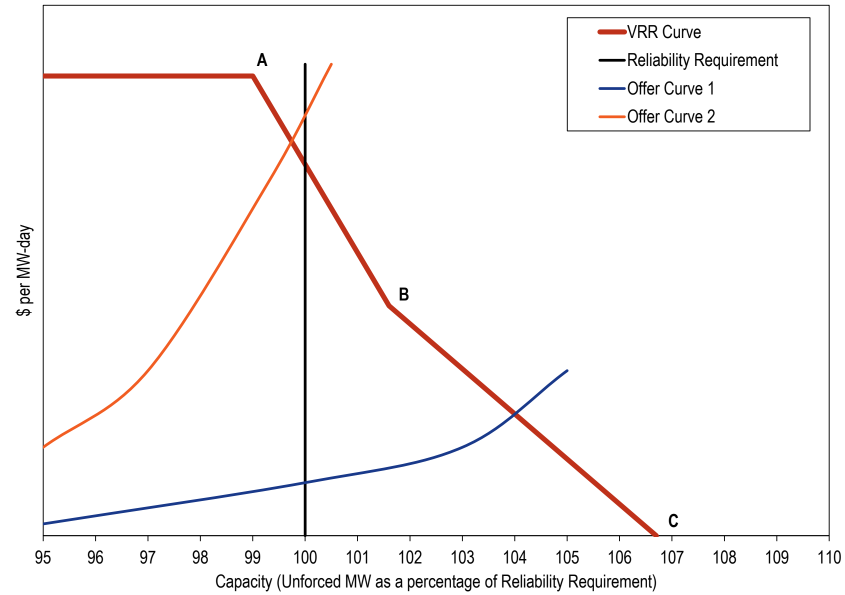
EMAAC had 948.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $8,903,095. PSEG had 499.4 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $7,028,755. BGE had 306.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $6,734,907.

Demand Curve

Effective for the 2018/2019 and subsequent Delivery Years, PJM revised the variable resource requirement (VRR) curve. The starting MW point of the downward sloping demand curve is set at 99.0 percent of the reliability requirement. The highest MW point is set at 106.7 percent of the reliability requirement. Almost all of the downward sloping part of the VRR curve lies to the right side of the reliability requirement.

The PJM definition of the VRR curve means the clearing price and cleared quantity will be higher, almost without exception, using the current VRR curve than using a vertical demand curve at the reliability requirement. As a result, payments for capacity will be higher. Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2022/2023 RPM BRA. The clearing price and cleared quantity would be lower if a vertical VRR curve set at the reliability requirement were used in place of the existing VRR curve. This is the case if the supply curve intersects the VRR curve to the right side of the reliability requirement (Offer Curve 1). The only exception would be if the supply curve intersects the VRR curve to the left of the reliability requirement (Offer Curve 2). In that case, the clearing price and cleared quantity would be higher with the vertical demand curve than with the existing VRR curve. In almost all RPM auctions, the offer curve intersected the VRR curve to the right side of the vertical demand curve.

Figure 5-4 VRR curve relative to the reliability requirement: 2022/2023 Delivery Year



Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2021/2022 RPM Second Incremental Auction two participants in the EMAAC LDA market passed the three pivotal supplier (TPS) test.[62] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[63 64 65]

62 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.
63 See OATT Attachment DD § 6.5.
64 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
65 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for planned generation capacity resource and creating a new definition for existing generation capacity resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a planned generation capacity resource. See 134 FERC ¶ 61,065 (2011).

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-9 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

Table 5-9 RSI results: 2019/2020 through 2021/2022 RPM Auctions[66]

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2019/2020 Base Residual Auction				
RTO	0.81	0.66	131	131
EMAAC	0.79	0.23	6	6
ComEd	0.74	0.12	6	6
BGE	0.00	0.00	1	1
2019/2020 First Incremental Auction				
RTO	0.63	0.50	53	53
EMAAC	0.00	0.00	5	5
2019/2020 Second Incremental Auction				
RTO	0.61	0.48	38	38
BGE	0.00	0.00	1	1

66 The RSI shown is the lowest RSI in the market.

Table 5-9 RSI results: 2019/2020 through 2021/2022 RPM Auctions (cont'd)

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2019/2020 Third Incremental Auction				
RTO	0.70	0.59	72	72
2020/2021 Base Residual Auction				
RTO	0.81	0.69	119	119
MAAC	0.67	0.77	24	24
EMAAC	0.45	0.18	21	21
ComEd	0.47	0.20	14	14
DEOK	0.00	0.00	1	1
2020/2021 First Incremental Auction				
RTO	0.47	0.42	47	47
2020/2021 Second Incremental Auction				
RTO	0.40	0.56	34	34
2020/2021 Third Incremental Auction				
RTO	0.54	0.72	59	59
MAAC	0.25	0.18	14	14
2021/2022 Base Residual Auction				
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3
2021/2022 First Incremental Auction				
RTO	0.57	0.48	26	26
EMAAC	0.00	0.82	5	3
PSEG	0.00	0.00	1	1
PSEG North	0.00	0.00	2	2
BGE	0.00	0.00	1	1
2021/2022 Second Incremental Auction				
RTO	0.19	0.12	19	19
EMAAC	0.05	0.23	7	5
PSEG	0.00	0.00	2	2
BGE	0.00	0.00	0	0

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 delivery year, an LDA is modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[67] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[68] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement are established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, are established for each modeled LDA.[69] Effective for the 2018/2019 through the 2019/2020 Delivery Years, Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, are established for each modeled LDA.

Locational Deliverability Areas are shown in Figure 5-5, Figure 5-6 and Figure 5-7.

Figure 5-5 Map of locational deliverability areas

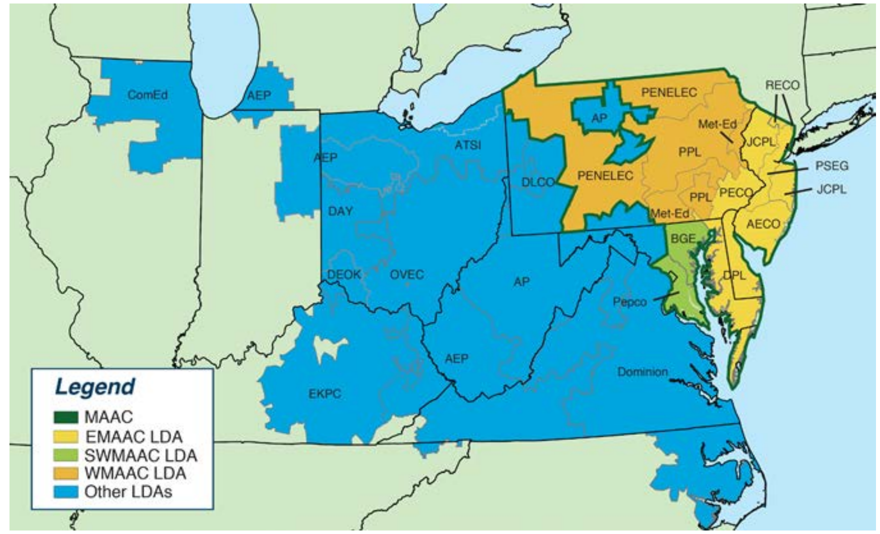
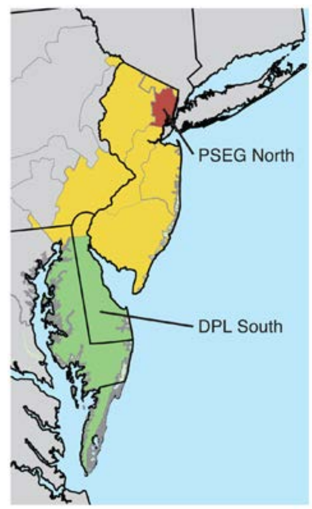
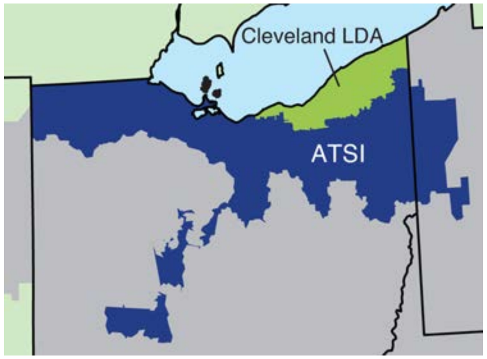


Figure 5-6 Map of RPM EMAAC subzonal LDAs



67 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
68 OATT Attachment DD § 5.10 (a) (ii).
69 146 FERC ¶ 61,052 (2014).

Figure 5-7 Map of RPM ATSI subzonal LDA



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[70]

The PJM market rules should not create inappropriate barriers to either the import or export of capacity. The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market equal to ICAP MW. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the day-ahead energy market should be clarified for both internal and external resources.

For the 2017/2018 through the 2019/2020 Delivery Years, Capacity Import Limits (CILs) are established for each of the five external source zones and the overall PJM region to account for the risk that external generation resources may not be able to deliver energy during the relevant delivery year due to the curtailment of firm transmission by third parties.[71] Capacity market sellers may request an exception to the CIL for an external generation resource by committing that the resource will be pseudo tied prior to the start of the relevant delivery year, by demonstrating that it has long-term firm transmission service confirmed on the complete transmission path from the resource to PJM, and by agreeing to be subject to the same RPM must offer requirement as internal PJM generation resources.

Effective June 9, 2015, an external generation capacity resource must obtain an exception to the CILs to be eligible to offer as a Capacity Performance Resource, which means that effective with the 2020/2021 Delivery Year, CILs are no longer defined as an RPM parameter.[72]

Effective May 9, 2017, enhanced pseudo tie requirements for external generation capacity resources were implemented, including a transition period with deliverability requirements for existing pseudo tie resources that have previously cleared an RPM auction.[73] The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market to market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo tie; a model consistency requirement; the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in

70 OATT Attachment DD § 5.6.6(b).

71 147 FERC ¶ 61,060 (2014).
72 151 FERC ¶ 61,208 (2015).
73 161 FERC ¶ 61,197 (2017), *order denying reh'g*, 170 FERC ¶ 61,217 (2020).

effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

As shown in Table 5-10, of the 4,470.4 MW of imports offered in the 2021/2022 RPM Base Residual Auction, 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (47.1 percent) were from MISO.

Table 5-10 RPM imports: 2007/2008 through 2021/2022 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8

Demand Resources

There are two basic demand products incorporated in the RPM market design:[74]

- **Demand Resources (DR).** Interruptible load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Energy Efficiency (EE) Resources.** Load resources that are offered into an RPM auction as capacity and receive the relevant LDA or RTO resource clearing price. The EE resource type was eligible to be offered in RPM auctions starting with the 2012/2013 Delivery Year and in incremental auctions in the 2011/2012 Delivery Year.[75]

Effective for the 2018/2019 and the 2019/2020 Delivery Years, there are two types of demand resource and energy efficiency resource products included in the RPM market design:[76 77]

- **Base Capacity Resources**
  - **Base Capacity Demand Resources.** A demand resource that is required to be available on any day from June through September for an unlimited number of interruptions. Base capacity DR is required to be capable of maintaining each interruption for at least 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Base Capacity Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast for the delivery year for which the base capacity energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the base capacity energy efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.

74 Effective June 1, 2007, the PJM active load management (ALM) program was replaced by the PJM load management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered into RPM auctions as capacity resources and receive the clearing price.
75 Letter Order, Docket No. ER10-366-000 (January 22, 2010).
76 151 FERC ¶ 61,208.
77 PJM Reliability Assurance Agreement Article 1.

- **Capacity Performance Resources**
  - **Annual Demand Resources.** A demand resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only 10 hours during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
  - **Annual Energy Efficiency Resources.** A project designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the annual energy efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, and the period from the hour ending 8:00 EPT and the hour ending 9:00 EPT and the period from the hour ending 19:00 EPT and the hour ending 20:00 EPT from January through February, excluding weekends and federal holidays.

Effective with the 2020/2021 Delivery Year, the Capacity Performance Product will be the only capacity product type, with two possible season types, annual and summer.

- **Annual Capacity Performance Resources**
  - Annual Demand Resources
  - Annual Energy Efficiency Resources
- **Seasonal Capacity Performance Resources**
  - **Summer-Period Demand Resources.** A demand resource that is required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions. Summer period DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Summer-Period Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the summer-period efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.

As shown in Table 5-11, Table 5-12, and Table 5-13, capacity in the RPM load management programs was 10,586.0 MW for June 1, 2020, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2020/2021 Delivery Year (13,015.2 MW) less replacement capacity (2,429.2 MW).

Table 5-11 RPM load management statistics by LDA: June 1, 2018 to June 1, 2021[78 79 80]

		UCAP (MW)														
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
	DR cleared	11,435.4	4,361.9	1,707.2	1,226.4	86.8	389.9	139.2	559.3	1,034.3	287.2	1,895.2	667.1	716.2		
	EE cleared	2,296.3	706.8	315.9	317.6	9.2	102.0	45.2	186.1	184.4	33.2	807.4	131.5	43.1		
01-Jun-18	DR net replacements	(3,182.4)	(1,268.4)	(584.3)	(199.5)	(52.4)	(150.9)	(43.6)	(25.6)	(261.0)	(136.7)	(430.0)	(173.9)	(220.0)		
	EE net replacements	248.8	163.0	45.5	107.6	1.1	22.4	9.1	(8.9)	14.7	4.7	29.0	116.5	5.4		
	RPM load management	10,798.1	3,963.3	1,484.3	1,452.1	44.7	363.4	149.9	710.9	972.4	188.4	2,301.6	741.2	544.7		
	DR cleared	10,703.1	3,878.9	1,659.2	817.0	91.3	381.2	176.5	554.6	1,047.0	333.9	1,759.9	262.4	741.4		
	EE cleared	2,528.5	821.4	395.3	301.7	7.8	134.5	52.8	170.0	204.8	41.7	792.9	131.7	72.7		
01-Jun-19	DR net replacements	(2,138.8)	(1,004.2)	(468.8)	(129.0)	(40.9)	(141.5)	(86.6)	(74.8)	(130.3)	(123.1)	(143.0)	(54.2)	(208.9)		
	EE net replacements	(50.0)	(24.1)	4.7	3.3	(0.2)	2.7	9.1	2.2	3.4	0.0	0.0	1.1	(20.4)		
	RPM load management	11,042.8	3,672.0	1,590.4	993.0	58.0	376.9	151.8	652.0	1,124.9	252.5	2,409.8	341.0	584.8		
	DR cleared	9,445.7	2,829.1	1,168.9	485.8	72.6	339.0	152.7	236.3	951.7	231.9	1,657.3	249.5	616.6	241.5	184.7
	EE cleared	3,569.5	1,288.8	700.3	394.5	28.8	246.1	111.3	196.2	356.0	72.9	852.0	198.3	111.4	79.5	105.6
01-Jun-20	DR net replacements	(2,399.5)	(858.7)	(369.0)	(176.5)	(29.7)	(136.5)	(89.0)	(53.3)	(121.1)	(36.2)	(314.5)	(123.2)	(171.0)	(66.1)	(27.5)
	EE net replacements	(29.7)	(0.5)	(0.3)	5.9	0.0	(6.3)	12.0	(0.6)	(0.2)	0.0	(0.1)	6.5	(5.2)	0.0	(5.0)
	RPM load management	10,586.0	3,258.7	1,499.9	709.7	71.7	442.3	187.0	378.6	1,186.4	268.6	2,194.7	331.1	551.8	254.9	257.8
	DR cleared	11,419.8	3,454.1	1,381.5	624.9	66.3	410.5	188.6	345.9	1,196.8	272.8	2,073.7	279.0	697.7	227.7	220.5
	EE cleared	4,031.0	1,549.0	853.8	438.6	31.9	351.4	135.1	213.4	330.6	73.7	895.0	225.2	142.0	83.4	114.8
01-Jun-21	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RPM load management	15,450.8	5,003.1	2,235.3	1,063.5	98.2	761.9	323.7	559.3	1,527.4	346.5	2,968.7	504.2	839.7	311.1	335.3

78 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
79 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The reported replacement transactions may include transactions associated with PJM members that were declared in collateral default.
80 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2021[81 82 83]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0	(1.0)	8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,419.8	0.0	0.0	11,419.8	0.0	11,419.8	0.0	1.087	0.0

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2021[84 85]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-08	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-09	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-10	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-11	76.4	0.0	0.2	76.6	0.0	76.6
01-Jun-12	666.1	0.0	(34.9)	631.2	(5.1)	626.1
01-Jun-13	904.2	0.0	120.6	1,024.8	(13.5)	1,011.3
01-Jun-14	1,077.7	0.0	204.7	1,282.4	(0.2)	1,282.2
01-Jun-15	1,189.6	0.0	335.9	1,525.5	(0.9)	1,524.6
01-Jun-16	1,723.2	0.0	61.1	1,784.3	(0.5)	1,783.8
01-Jun-17	1,922.3	0.0	195.6	2,117.9	(7.4)	2,110.5
01-Jun-18	2,296.3	0.0	248.8	2,545.1	0.0	2,545.1
01-Jun-19	2,528.5	0.0	(50.0)	2,478.5	0.0	2,478.5
01-Jun-20	3,569.5	0.0	(29.7)	3,539.8	(0.1)	3,539.7
01-Jun-21	4,031.0	0.0	0.0	4,031.0	0.0	4,031.0

81 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
82 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.
83 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.
84 Pursuant to the OA § 15.1.6(c), PJM Settlement shall close out and liquidate all forward positions of PJM members that are declared in default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.
85 Effective with the 2019/2020 Delivery Year, available capacity from an EE Resource can be used to replace only EE Resource commitments. This rule change and related EE add back rule changes were endorsed at the December 17, 2015, meeting of the PJM Markets and Reliability Committee.

Market Conduct

Offer Caps and Offer Floors

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the capacity market seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[86] [87] [88] For Base Capacity, offer caps are defined in the PJM Tariff as avoidable costs less PJM market revenues, or opportunity costs based on the potential sale of capacity in an external market. For Capacity Performance Resources, offer caps are defined in the PJM Tariff as the applicable zonal net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year, unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market exceed this level. For RPM Third Incremental Auctions, capacity market sellers may elect, for Base Capacity offers, an offer cap equal to 1.1 times the BRA clearing price for the relevant LDA and delivery year or, for Capacity Performance offers, an offer cap equal to the greater of the net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year.

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[89] In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a generation capacity resource, termed Avoidable Project Investment Recovery (APIR). Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. For Capacity Performance Resources, avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts and expected bonus performance payments/nonperformance charges.[90] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for delivery years prior to 2020/2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[91]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).[92] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows capacity market sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Calculation of Offer Caps

The competitive offer of a Capacity Performance resource is based on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (Net ACR); and the resource's

86 See OATT Attachment DD § 6.5.
87 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
88 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).
89 OATT Attachment DD § 6.8 (b).
90 For details on the competitive offer of a capacity performance resource, see "Analysis of the 2021/2022 RPM Base Residual Auction—Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
91 OATT Attachment DD § 6.8(a).
92 151 FERC ¶ 61,208.

performance during performance assessment intervals (A) in the delivery year.[93]

The competitive offer of a Capacity Performance resource is also based on a market seller's expectations of system level variables: the number of performance assessment intervals (PAI) in a delivery year (H) where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The level of bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment hours for reasons defined in the PJM OATT.[94]

The default offer cap defined in the PJM tariff, Net CONE times the average Balancing Ratio, is based on a number of assumptions:

1. The Net ACR of a resource is less than its expected energy only bonuses:

$$ACR \leq \sum_{i=1}^{H}(CPBR_i \times A_i)$$

$$or\ ACR \leq \left(\frac{1}{12}\right)(CPBR \times H \times \bar{A})$$

2. The expected number of performance assessment intervals equals 360. (H = 360 intervals, or 12 hours)
3. The expected value of the bonus performance payment rate (CPBR) is equal to the nonperformance charge rate (PPR)
4. The average expected performance of the resource during performance assessment hours ($\bar{A}$)

The competitive offer of such a resource is:

$$p = \left(\frac{1}{12}\right)(CPBR \times H \times \bar{A} + PPR \times H \times (\bar{B} - \bar{A}))$$

In other words, the competitive offer of such a resource is the opportunity cost of taking on the capacity obligation which equals the sum of the energy only bonuses it would have earned $(CPBR \times H \times \bar{A})/12$ and the net nonperformance charges it would incur by taking on the capacity obligation $(PPR \times H \times (\bar{B} - \bar{A})/12)$. Both the components are proportional to the expected number of performance assessment intervals. If the expected number of performance assessment intervals (*H*) is significantly lower than the value used to determine the nonperformance charge rate (PPR), the opportunity of earning bonuses as an energy only resource, as well as the net nonperformance charges incurred by taking on a capacity obligation are lower. Under such a scenario, the likelihood that that the resource's Net ACR is lower than the expected energy only bonuses is reduced. For resources whose Net ACR is greater than the expected energy only bonuses, the competitive offer is the Net ACR adjusted with any capacity performance bonuses or nonperformance charges they expect to incur during the delivery year.

This means that when the expected number of performance assessment intervals are lower than the value used to determine the nonperformance charge rate (360 intervals, or 30 hours), the current default offer cap of Net CONE times B overstates the competitive offer and the market seller offer cap.

The recent history of a low number of emergency actions in PJM reflect the improvements to generator performance with the capacity performance design, the reduction in actual and expected pool wide outage rates as a result of new units added to the system and the retirement of old units, the upward biased peak load forecasts used in RPM, and the high reserve margins in capacity.[95] [96] Given these developments, the assumption that there would be 30 hours of emergency actions in a year that would trigger performance assessment intervals is unsupported. Since the nonperformance charge rate

93 The model is only applicable to generation resources and storage resources that have an annual obligation to perform with very limited specific excuses as defined in the PJM OATT.
94 OATT Attachment DD § 10A (d).
95 PJM experienced only one emergency event since April 2014 that triggered a PAI in an area that at least encompasses a PJM transmission zone. On October 2, 2019, PJM declared a pre-emergency load management action that triggered PAIs in four zones for a period of two hours or 24 five minute intervals.
96 See Table 5-7.

is defined in the tariff as net CONE divided by 30 hours, the adjusted default offer cap to reflect a lower estimate for the number of PAIs is much lower than net CONE times B.

In the 2021/2022 RPM Base Residual Auction, net CONE times B exceeded the actual competitive offer level of a Low ACR resource that the default offer cap is based on.[97] While most participants offered in the 2021/2022 RPM Base Residual Auction at competitive levels based on their expectation of the number of performance assessment hours and projected net revenues, some market participants did not offer competitively and affected the market clearing prices.

MOPR

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[98] The changes to the MOPR included updating the calculation of the net Cost of New Entry (CONE) for Combined Cycle (CC) and Combustion Turbine (CT) plants which is used as a benchmark value in assessing the competitiveness of a sell offer, increasing the percentage value used in the screen to 90 percent for CC and CT plants, eliminating the net-short requirement as a prerequisite for applying the MOPR, eliminating the impact screen, revising the process for reviewing proposed exceptions to the defined minimum sell offer price, and clarifying which resources are subject to the MOPR along with the duration of mitigation. Subsequent FERC Orders revised the MOPR, including clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process.[99]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[100] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exception process for those that do not qualify for the Competitive Entry or Self Supply Exemptions; changing the applicability of MOPR to include only combustion turbine, combined cycle, integrated gasification combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the transmission system; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen from 90 percent to 100 percent of the applicable net CONE values; and broadening the region subject to MOPR to the entire RTO from modeled LDAs only.

Effective December 8, 2017, FERC issued an order on remand rejecting PJM's MOPR proposal in Docket No. ER13-535, and as a result, the rules that were in effect prior to PJM's December 7, 2012, MOPR filing were reinstated. These changes include eliminating the Competitive Entry and Self Supply Exemptions and retaining only the Unit Specific Exception request; narrowing the region subject to MOPR from the entire RTO to only modeled LDAs; eliminating the 20.0 MW threshold for applicability; decreasing the screen from 90 percent to 100 percent of the applicable net CONE values; redefining the applicability criteria to exclude nuclear, coal, IGCC, hydroelectric, wind and solar facilities; modifying the duration of mitigation criteria from clearing in a prior delivery year to clearing in any delivery year; and changing the procedural deadlines.[101]

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.[102] The rules applying to natural gas fired capacity resources without state subsidies were retained. The changes include expanding the MOPR to new or existing state subsidized capacity resources; establishing a competitive exemption for new and existing resources other than natural gas fired resources while also allowing a resource specific exception process for those that do not qualify for the competitive exemption; defining limited categorical exemptions for renewable resources participating in renewable portfolio standards (RPS) programs, self supply, DR, EE, and capacity storage; defining the region subject to MOPR for capacity resources with state subsidy as the entire RTO; and defining the default offer price floor for capacity

97 See Monitoring Analytics, LLC "Analysis of the 2021/2022 RPM Base Residual Auction—Revised," at Attachment B <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
98 135 FERC ¶ 61,022 (2011).
99 135 FERC ¶ 61,022 (2011), *order on reh'g*, 137 FERC ¶ 61,145 (2011).
100 143 FERC ¶ 61,090 (2013).
101 161 FERC ¶ 61,252 (2017).
102 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020).

resources with state subsidies as 100 percent of the applicable net CONE or net ACR values.

2021/2022 RPM Second Incremental Auction

As shown in Table 5-14, 276 generation resources submitted Capacity Performance offers in the 2021/2022 RPM Third Incremental Auction. Unit specific offer caps were calculated for zero generation resources (0.0 percent). Of the 276 generation resources, 241 generation resources had the net CONE times B offer cap (87.3 percent), 20 generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units (7.2 percent), 10 Planned Generation Capacity Resources had uncapped offers (3.6 percent), and the remaining five generation resources were price takers (1.8 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

MOPR Statistics

Market power mitigation measures are applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception.

As shown in Table 5-15, of the 844.4 ICAP MW of MOPR Unit-Specific Exception requests for the 2021/2022 RPM Second Incremental Auction, requests for 844.4 MW were granted.

Table 5-14 ACR statistics: RPM auctions conducted in third quarter, 2020

	2021/2022 Second Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	NA	NA
Unit specific ACR (APIR)	0	0.0%
Unit specific ACR (APIR and CPQR)	0	0.0%
Unit specific ACR (non-APIR)	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%
Opportunity cost input	0	0.0%
Default ACR and opportunity cost	NA	NA
Net CONE times B	241	87.3%
Offer cap of 1.1 times BRA clearing price elected	NA	NA
Uncapped planned uprate and default ACR	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%
Uncapped planned uprate and Net CONE times B	20	7.2%
Uncapped planned uprate and price taker	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA
Uncapped planned generation resources	10	3.6%
Existing generation resources as price takers	5	1.8%
Total Generation Capacity Resources offered	276	100.0%

Table 5-15 MOPR statistics: RPM auctions conducted in third quarter, 2020[103]

		Number of Requests (Company-Plant Level)	ICAP (MW) Requested	ICAP (MW) Granted	ICAP (MW) Offered	UCAP (MW) Offered	UCAP (MW) Cleared
2021/2022 Second Incremental Auction	Unit-Specific Exception	19	844.4	844.4	16.2	16.0	0.0
	Other MOPR Screened Generation Resources	0	0.0	0.0	140.1	137.0	0.0
	Total	19	844.4	844.4	156.3	153.0	0.0

Replacement Capacity[104]

Table 5-16 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2021. The 2021 numbers are not final.

Table 5-16 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2021

	UCAP (MW) RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	177,064.2	0.0	(12,300.3)	164,763.9	(9.3)	164,754.6
01-Jun-20	174,023.8	(335.3)	(10,582.7)	163,105.8	(5.7)	163,100.1
01-Jun-21	169,478.0	0.0	(673.5)	168,804.5	0.0	168,804.5

Market Performance

Figure 5-8 shows cleared MW weighted average capacity market prices on a delivery year basis for the entire history of the PJM capacity markets.

Table 5-17 shows RPM clearing prices for all RPM auctions held through the first nine months of 2020, and Table 5-18 shows the RPM cleared MW for all RPM auctions held through the first nine months of 2020.

Figure 5-9 shows the RPM cleared MW weighted average prices for each LDA for the current delivery year and all results for auctions for future delivery years that have been held through the first nine months of 2020. A summary of these weighted average prices is given in Table 5-19.

Table 5-20 shows RPM revenue by delivery year for all RPM auctions held through the first nine months of 2020 based on the unforced MW cleared and the resource clearing prices. In 2019/2020, RPM revenue was $7.1 billion. In 2020/2021, RPM revenue was $7.0 billion.

Table 5-21 shows RPM revenue by calendar year for all RPM auctions held through the first nine months of 2020. In 2018, RPM revenue was $10.3 billion. In 2019, RPM revenue was $8.7 billion.

Table 5-22 shows the RPM annual charges to load. For the 2018/2019 Delivery Year, RPM annual charges to load were $11.0 billion. For the 2020/2021 Delivery Year, annual charges to load are $7.0 billion.

103 There were additional MOPR Screened Generation Resources for which no exceptions or exemptions were requested and to which the MOPR floor was applied. Some numbers are not reported as a result of PJM confidentiality rules.
104 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

Table 5-17 Capacity market clearing prices: 2007/2008 through 2021/2022 RPM Auctions

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2019/2020 BRA	Base Capacity	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$80.00	$80.00	$182.77	$80.30
2019/2020 BRA	Base Capacity DR/EE	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$0.01	$80.00	$182.77	$80.30
2019/2020 BRA	Capacity Performance	$100.00	$100.00	$100.00	$100.00	$119.77	$100.00	$119.77	$119.77	$119.77	$100.00	$100.00	$202.77	$100.30
2019/2020 First Incremental Auction	Base Capacity	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Base Capacity DR/EE	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Capacity Performance	$51.33	$51.33	$51.33	$51.33	$58.55	$51.33	$58.55	$58.55	$58.55	$51.33	$51.33	$51.33	$51.33
2019/2020 Second Incremental Auction	Base Capacity	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14
2019/2020 Second Incremental Auction	Base Capacity DR/EE	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14
2019/2020 Second Incremental Auction	Capacity Performance	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$55.00
2019/2020 Third Incremental Auction	Base Capacity	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35
2019/2020 Third Incremental Auction	Base Capacity DR/EE	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$20.00	$21.35	$21.35	$21.35
2019/2020 Third Incremental Auction	Capacity Performance	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35
2020/2021 BRA	Capacity Performance	$76.53	$86.04	$76.53	$86.04	$187.87	$86.04	$187.87	$187.87	$187.87	$86.04	$76.53	$188.12	$86.04
2020/2021 First Incremental Auction	Capacity Performance	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90
2020/2021 Second Incremental Auction	Capacity Performance	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25
2020/2021 Third Incremental Auction	Capacity Performance	$10.00	$15.25	$10.00	$15.25	$15.25	$15.25	$15.25	$15.25	$15.25	$15.25	$10.00	$10.00	$15.25
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30
2021/2022 First Incremental Auction	Capacity Performance	$23.00	$23.00	$23.00	$23.00	$25.00	$23.00	$25.00	$45.00	$219.00	$23.00	$23.00	$23.00	$60.00
2021/2022 Second Incremental Auction	Capacity Performance	$10.26	$10.26	$10.26	$10.26	$15.37	$10.26	$15.37	$125.00	$125.00	$10.26	$10.26	$10.26	$70.00

Table 5-18 Capacity market cleared MW: 2007/2008 through 2021/2022 RPM Auctions[105]

		UCAP (MW)												
Delivery Year	Auction	RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE	TOTAL
2019/2020	BASE	60,061.8	9,996.2	9,066.6	12,754.9	20,382.4	1,598.5	5,583.1	3,228.9	6,971.7	10,291.1	22,971.4	4,422.9	167,329.5
2019/2020	FIRST	784.5	249.4	39.3	157.7	78.7	11.7	10.6	28.8	43.6	147.5	711.4	31.9	2,295.1
2019/2020	SECOND	442.9	160.4	30.1	146.2	210.1	21.2	38.1	44.8	41.9	263.6	105.8	107.5	1,612.6
2019/2020	THIRD	1,608.0	440.9	429.4	1,216.6	265.7	2.4	180.4	23.2	83.6	454.2	867.4	255.2	5,827.0
2020/2021	BASE	56,012.4	11,413.2	8,990.6	14,398.2	19,978.5	1,647.2	5,041.2	2,975.4	6,410.0	9,925.9	23,960.3	4,021.1	164,773.9
2020/2021	FIRST	1,265.6	331.0	144.2	83.4	76.2	38.9	105.8	32.0	97.8	666.9	644.4	38.7	3,524.8
2020/2021	SECOND	447.2	206.9	53.0	30.7	302.9	28.4	29.5	48.8	35.4	366.2	194.6	160.3	1,903.8
2020/2021	THIRD	1,106.6	569.7	118.7	89.0	194.1	33.1	423.0	137.0	93.1	554.3	127.7	39.8	3,486.0
2021/2022	BASE	55,642.6	12,565.1	10,136.1	15,368.6	19,857.3	1,673.8	4,667.2	3,134.1	6,546.1	8,010.5	22,358.1	3,667.8	163,627.3
2021/2022	FIRST	281.7	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	2,143.2
2021/2022	SECOND	1,307.8	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	3,707.5

105 The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-19 Weighted average clearing prices by zone: 2018/2019 through 2021/2022

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2018/2019	2019/2020	2020/2021	2021/2022
RTO				
AEP	$158.20	$93.63	$74.42	$137.02
APS	$158.20	$93.63	$74.42	$137.02
ATSI	$148.42	$92.97	$69.75	$149.70
Cleveland	$158.68	$89.17	$68.93	$106.96
ComEd	$199.02	$188.90	$182.15	$191.17
DAY	$158.20	$93.63	$72.42	$138.19
DEOK	$158.20	$93.63	$121.24	$133.54
DLCO	$158.20	$93.63	$74.42	$137.02
Dominion	$158.20	$93.63	$74.42	$137.02
EKPC	$158.20	$93.63	$74.42	$137.02
MAAC				
EMAAC				
AECO	$214.31	$112.48	$182.04	$164.07
DPL	$214.31	$112.48	$182.04	$164.07
DPL South	$211.38	$115.95	$178.65	$161.07
JCPL	$214.31	$112.48	$182.04	$164.07
PECO	$214.31	$112.48	$182.04	$164.07
PSEG	$210.92	$110.56	$165.74	$199.70
PSEG North	$211.71	$116.03	$176.45	$202.27
RECO	$214.31	$112.48	$182.04	$164.07
SWMAAC				
BGE	$141.58	$88.20	$80.71	$189.98
Pepco	$144.90	$90.59	$84.24	$134.58
WMAAC				
Met-Ed	$152.65	$93.81	$81.85	$136.11
PENELEC	$152.65	$93.81	$81.85	$136.11
PPL	$147.90	$88.53	$85.07	$139.16

Table 5-20 RPM revenue by delivery year: 2007/2008 through 2021/2022[106]

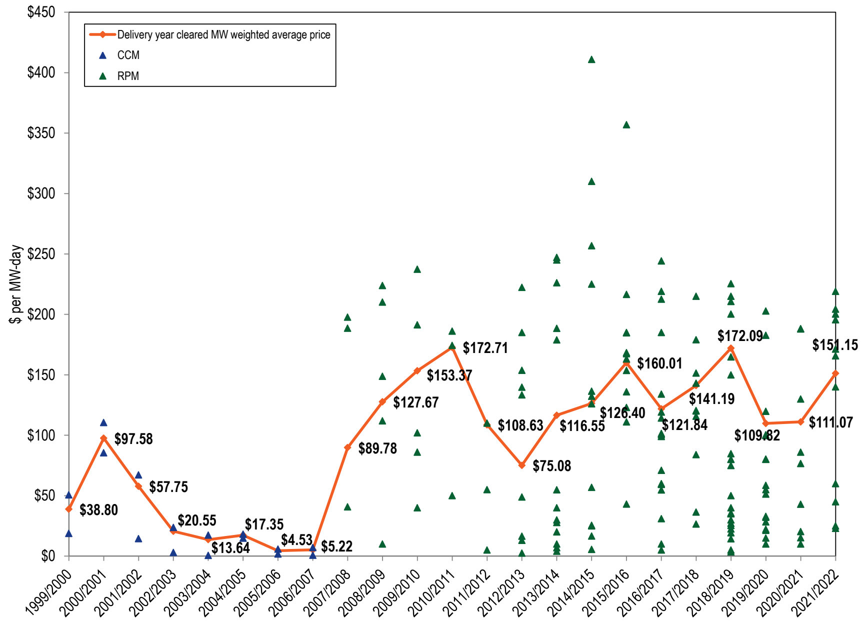
Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$108.63	134,182.6	366	$5,335,087,023
2012/2013	$75.08	141,283.9	365	$3,871,714,635
2013/2014	$116.55	159,844.5	365	$6,799,778,047
2014/2015	$126.40	161,205.0	365	$7,437,267,646
2015/2016	$160.01	173,519.4	366	$10,161,726,902
2016/2017	$121.84	179,749.0	365	$7,993,888,695
2017/2018	$141.19	180,590.5	365	$9,306,676,719
2018/2019	$172.09	175,996.0	365	$11,054,943,851
2019/2020	$109.82	177,064.2	366	$7,116,815,360
2020/2021	$111.07	173,688.5	365	$7,041,524,517
2021/2022	$151.15	169,478.0	365	$9,349,894,658

Table 5-21 RPM revenue by calendar year: 2007 through 2022[107]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	75,665.5	214	$2,486,310,108
2008	$111.93	130,332.1	366	$5,334,880,241
2009	$142.74	132,623.5	365	$6,917,391,702
2010	$164.71	134,033.7	365	$8,058,113,907
2011	$135.14	133,907.1	365	$6,615,032,130
2012	$89.01	138,561.1	366	$4,485,656,150
2013	$99.39	152,166.0	365	$5,588,442,225
2014	$122.32	160,642.2	365	$7,173,539,072
2015	$146.10	168,147.0	365	$9,018,343,604
2016	$137.69	177,449.8	366	$8,906,998,628
2017	$133.19	180,242.4	365	$8,763,578,112
2018	$159.31	177,896.7	365	$10,331,688,133
2019	$135.58	176,338.6	365	$8,734,613,179
2020	$110.55	175,368.7	366	$7,084,072,778
2021	$134.57	171,219.9	365	$8,394,925,093
2022	$151.15	70,112.8	151	$3,868,038,612

106 The results for the ATSI Integration Auctions are not included in this table.
107 The results for the ATSI Integration Auctions are not included in this table.

Figure 5-8 History of capacity prices: 1999/2000 through 2021/2022[108]



108 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2021/2022 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM resource clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-9 Map of RPM capacity prices: 2018/2019 through 2021/2022

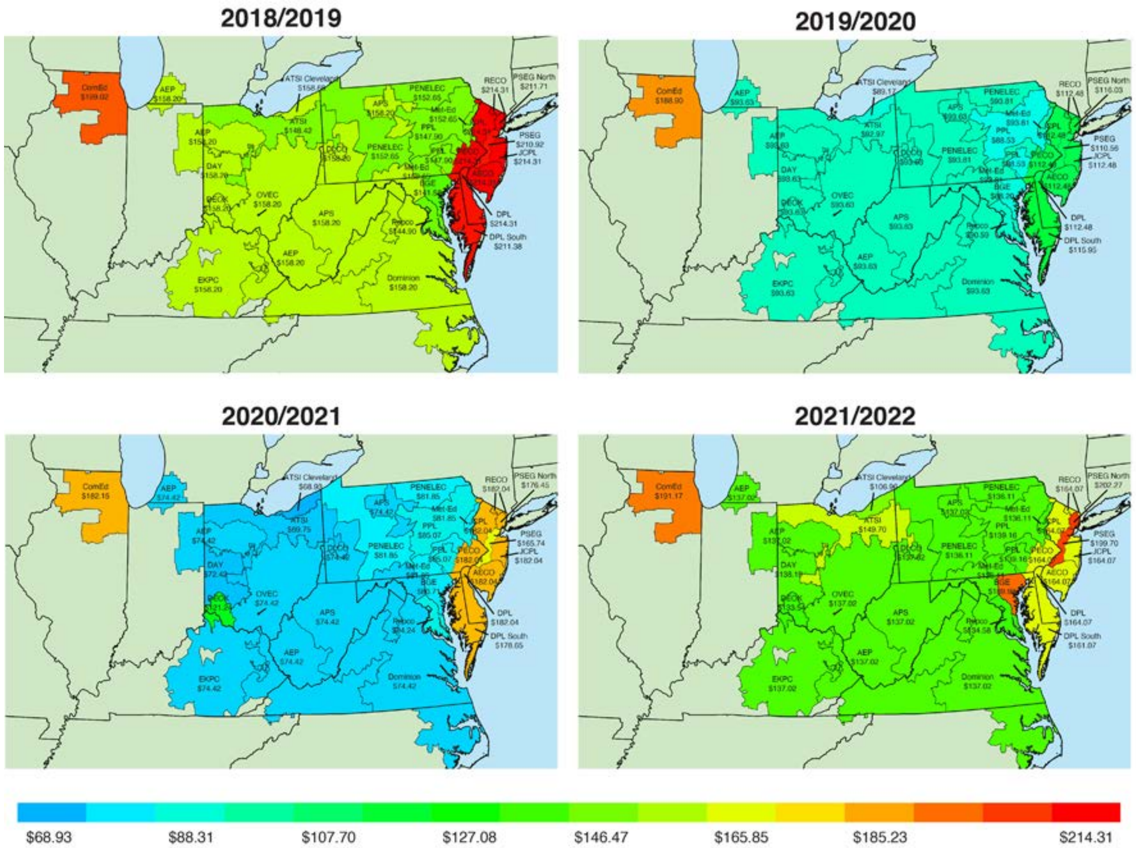


Table 5-22 RPM cost to load: 2019/2020 through 2021/2022 RPM Auctions[109 110 111]

	Zonal Capacity Price ($ per MW-Day)	Zonal CTR Credit Rate ($ per MW-Day)	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Days	Annual Charges	Charges per Day
2019/2020							
Rest of RTO	$98.07	$0.00	$98.07	89,185.9	366	$3,201,364,940	$8,746,899
Rest of EMAAC	$117.92	$2.35	$115.58	24,415.1	366	$1,032,810,556	$2,821,887
BGE	$97.22	-$0.56	$97.79	7,595.2	366	$271,828,430	$742,701
ComEd	$195.99	$3.43	$192.56	24,985.1	366	$1,760,892,086	$4,811,181
Pepco	$92.90	$0.00	$92.90	7,330.3	366	$249,230,694	$680,958
PSEG	$118.18	$2.35	$115.83	11,281.1	366	$478,247,326	$1,306,687
Total				164,792.8		$6,994,374,033	
2020/2021							
Rest of RTO	$77.31	$0.00	$77.31	69,073.7	365	$1,949,098,489	$5,339,996
Rest of MAAC	$86.98	-$0.08	$87.06	29,555.9	365	$939,246,366	$2,573,278
EMAAC	$187.13	$12.80	$174.32	35,740.4	365	$2,274,098,760	$6,230,408
ComEd	$190.04	$0.12	$189.92	23,744.7	365	$1,645,988,210	$4,509,557
DEOK	$128.73	$24.23	$104.50	5,072.0	365	$193,459,838	$530,027
Total				163,186.7		$7,001,891,663	
2021/2022							
Rest of RTO	$142.71	$0.00	$142.71	81,244.5	365	$4,232,062,441	$11,594,692
Rest of EMAAC	$168.34	$3.44	$164.89	23,999.1	365	$1,444,396,169	$3,957,250
ATSI	$168.49	$7.71	$160.78	13,978.7	365	$820,348,098	$2,247,529
BGE	$205.09	$40.51	$164.58	7,316.9	365	$439,530,736	$1,204,194
ComEd	$198.71	$0.00	$198.71	23,149.9	365	$1,679,053,039	$4,600,145
PSEG	$210.74	$22.72	$188.02	11,275.2	365	$773,794,246	$2,119,984
Total				160,964.3		$9,389,184,729	

Timing of Unit Retirements

Generation owners that want to deactivate a unit, either to mothball or permanently retire, must provide notice to PJM and the MMU at least 90 days prior to the proposed deactivation date. Generation owners seeking a capacity market must offer exemption for a delivery year must submit their deactivation request no later than the December 1 preceding the Base Residual Auction or 120 days before the start of an Incremental Auction for that delivery year.[112] If no reliability issues are found during PJM's analysis of the retirement's impact on the transmission system, and the MMU finds no market power issues associated with the proposed deactivation, the unit may deactivate at any time thereafter.[113]

Table 5-23 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through September 2020. Of the 69 deactivation requests submitted, 17 units (24.6 percent) deactivated an average of 232 days earlier than their initially requested date; 11 units (15.9 percent) deactivated an average of 84 days later than the originally requested deactivation date; and 22 units (31.9 percent) deactivated on their initially requested date. Eleven (15.9 percent) of the unit deactivations were cancelled an average of 465 days before their scheduled deactivation date, and 8 (11.6 percent) of the unit deactivations have not yet reached their target retirement date.

Table 5-23 Timing of actual unit deactivations compared to initially requested deactivation date: Requests submitted January 2018 through September 2020

	Number of Units	Percent	Average Deviation from Originally Requested Date
Early	17	24.6%	(232)
Late	11	15.9%	84
On time	22	31.9%	0
Cancelled	11	15.9%	(465)
Pending	8	11.6%	-
Total	69	100.0%	-

109 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.
110 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone. There is no separate obligation for ATSI Cleveland as the ATSI Cleveland LDA is completely contained within the ATSI Zone.
111 The net load prices and obligation MW for 2021/2022 are not finalized.
112 OATT Attachment DD § 6.6(g).
113 OATT Part V §113

Reliability Must Run (RMR) Service

PJM must make out of market payments to units for Reliability Must Run (RMR) service during periods when a unit that would otherwise have been deactivated is needed for reliability.[114] The need for RMR service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[115]

When notified of an intended deactivation, the MMU performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[116] PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[117] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to provide RMR service.[118] The PJM market rules do not require an owner to provide RMR service, but owners must provide 90 days advance notice of a proposed deactivation.[119] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[120] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction, an owner must show "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM, 120 days prior to such auction.[121]

114 OATT Part V §114
115 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").
116 OATT § 113.2; OATT Attachment M § IV.1.
117 OATT § 113.2.
118 *Id.*
119 OATT § 113.1.
120 OATT Attachment DD § 6.6(g).
121 *Id.*

Under the current rules, a unit providing RMR service can recover its costs under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[122] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit."[123] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[124] The rules provide terms for early termination of RMR service and for the repayment of project investment by owners of units that choose to keep units in service after the RMR period ends.[125] Project investment is capped at $2 million, above which FERC approval is required.[126] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC.[127]

122 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Adder) * MW capability of the unit * Number of days in the month) – Actual Net Revenues).
123 OATT § 115.
124 *Id.*
125 OATT § 118.
126 OATT §§ 115, 117.
127 OATT § 119.

Table 5-24 shows units that have provided RMR service to PJM.

Table 5-24 RMR service summary

Unit Names	Owner	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
B.L. England 2	RC Cape May Holdings, LLC	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	30-Apr-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
B.L. England 3	RC Cape May Holdings, LLC	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

Only two of seven owners have used the deactivation avoidable cost rate approach. The other five owners used the cost of service recovery rate, despite the greater administrative expense.

In each of the cost of service recovery rate filings for RMR service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the RMR service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to establish a rate base including investment in the existing plant and new investment necessary to provide RMR service and to earn a return on that rate base and receive depreciation of that rate base. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the RMR service period and have included costs incurred prior to the decision to the deactivate and costs associated with closing the unit that would have been incurred regardless of the RMR service period.[128] In one cost of service recovery rate, the filing included costs that already had been written off on the company's public books.[129] Unit owners have filed for revenues under the cost of service method that substantially exceed the actual incremental costs of providing RMR service.

Because an RMR unit is needed by PJM for reliability reasons, and the provision of RMR service is voluntary in PJM, owners of RMR service have significant market power in establishing the terms of RMR service.

RMR service should be provided to PJM customers at reasonable rates, which reflect the riskless nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed

128 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000 and ER17-1083-000.
129 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.

recovery of 100 percent of the actual incremental costs incurred to provide the service plus an incentive markup.

The cost of service recovery rates have been excessive compared to the actual incremental costs of providing RMR service. The DACR method also provides excessive incentives for service longer than a year, given that customers bear the risks.

The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V.

The MMU also recommends, based in part on its experience with application of the deactivation avoidable cost rate and proceedings filed under Section 119, the following improvements to the DACR provisions:

- Revise the applicable adders in Section 114 to be 15 percent for the second year of RMR service and 20 percent for the provision of RMR service in excess of two years.
- Add true up provisions that ensure that the RMR service provider is reimbursed for, and consumers pay for, the actual incremental costs associated with the RMR service, plus the applicable adder.
- Eliminate the $2 million cap on project investment expenditures.
- Clearly distinguish operating expenses and project investment costs.
- Clarify the tariff language in Section 118 regarding the refund of project investment in the event the RMR unit continues operation beyond the RMR term.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-25 shows the capacity factors by unit type in the first nine months of 2019 and 2020. In the first nine months of 2020, nuclear units had a capacity factor of 93.1 percent, compared to 92.7 percent in the first nine months of 2019; combined cycle units had a capacity factor of 55.2 percent in the first nine months of 2020, compared to a capacity factor of 55.0 percent in the first nine months of 2019; all steam units had a capacity factor of 23.3 percent in the first nine months of 2020, compared to 28.7 percent in the first nine months of 2019; coal units had a capacity factor of 25.4 percent in the first nine months of 2020, compared to 31.6 percent in the first nine months of 2019.

Table 5-25 Capacity factor (By unit type (GWh)): January through September, 2019 and 2020[130 131]

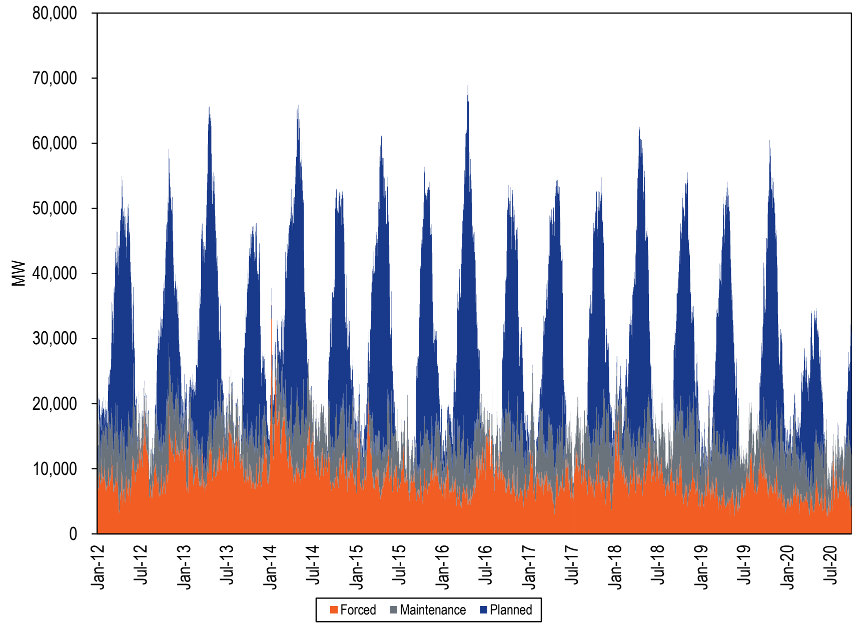
	2019 (Jan-Sep)		2020 (Jan-Sep)		
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Change in 2020 from 2019
Battery	15.1	0.7%	27.0	1.2%	0.5%
Combined Cycle	211,909.2	55.0%	229,071.1	55.2%	0.1%
Single Fuel	180,345.5	57.4%	194,993.4	56.7%	(0.7%)
Dual Fuel	31,563.7	44.7%	34,077.7	48.1%	3.4%
Combustion Turbine	12,167.9	5.3%	15,069.9	6.7%	1.3%
Single Fuel	8,174.8	5.0%	10,573.3	6.5%	1.6%
Dual Fuel	3,993.1	6.4%	4,496.7	7.1%	0.8%
Diesel	200.3	6.2%	188.5	5.6%	(0.7%)
Single Fuel	196.3	7.4%	182.6	6.5%	(0.9%)
Dual Fuel	4.0	0.7%	5.9	1.0%	0.3%
Diesel (Landfill gas)	1,267.2	43.6%	1,182.9	42.6%	(0.9%)
Fuel Cell	163.1	77.9%	170.3	81.0%	3.1%
Nuclear	210,535.4	92.7%	207,426.7	93.1%	0.4%
Pumped Storage Hydro	4,597.2	10.6%	4,839.4	11.1%	0.5%
Run of River Hydro	8,818.5	33.8%	8,108.9	30.9%	(2.8%)
Solar	2,218.6	21.0%	2,977.8	20.7%	(0.3%)
Steam	166,172.0	28.7%	127,877.2	23.3%	(5.4%)
Biomass	4,563.1	55.2%	4,203.5	53.0%	(2.2%)
Coal	156,702.4	31.6%	118,216.2	25.4%	(6.2%)
Single Fuel	153,788.9	32.5%	116,152.6	26.2%	(6.3%)
Dual Fuel	2,913.5	13.1%	2,063.5	9.5%	(3.6%)
Natural Gas	4,807.9	35.5%	5,384.4	37.1%	1.6%
Single Fuel	354.1	41.2%	344.7	42.4%	1.2%
Dual Fuel	4,453.8	21.4%	5,039.7	23.3%	1.8%
Oil	98.6	0.4%	73.0	0.5%	0.1%
Wind	16,973.8	27.2%	17,986.2	25.8%	(1.4%)
Total	635,041.1	40.5%	614,930.3	39.1%	(1.4%)

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The MW on outage vary throughout the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-10, due to restrictions on planned outages during the winter and summer. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-14.

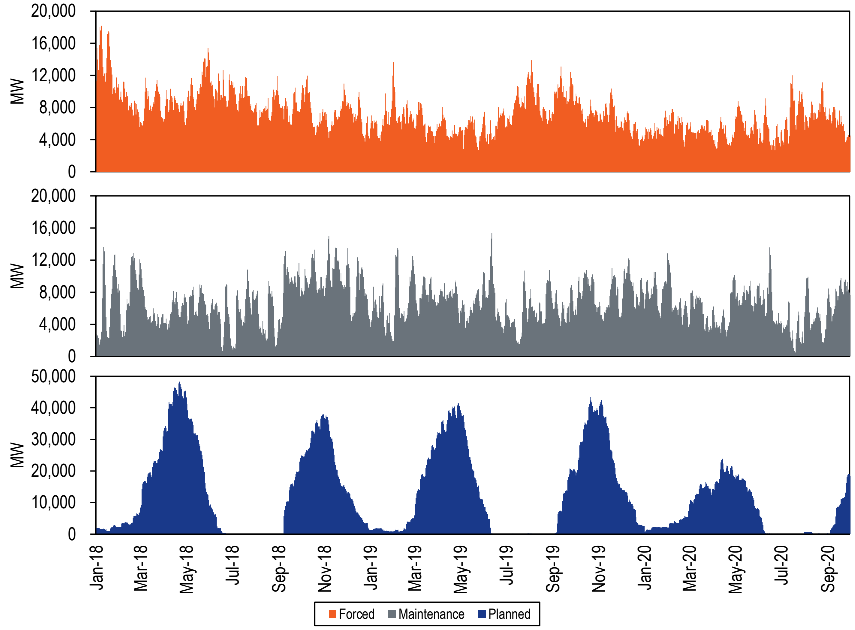
130 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.
131 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.

Figure 5-10 Outages (MW): 2012 through September 2020



In the first nine months of 2020, forced and planned outages were lower than in 2018 and 2019 (Figure 5-11). The MWh of planned outages in the first nine months of 2020 were 31 percent lower than in the first nine months of 2019 and the MWh of forced outages were 4 percent lower than in the first nine months of 2019. The MWh of maintenance outages were 1 percent higher than in the first nine months of 2019.

Figure 5-11 Outages (MW): Forced, maintenance and planned outages 2018 through September 2020



Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-12. Metrics by unit type are shown in Table 5-26.

Figure 5-12 Equivalent outage and availability factors: January through September, 2007 to 2020

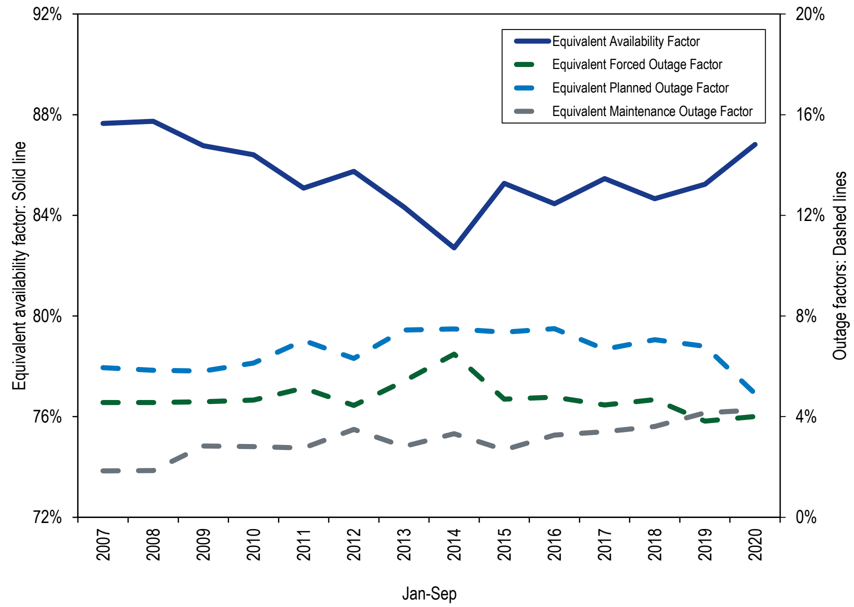


Table 5-26 EFOF, EPOF, EMOF and EAF by unit type: January through September, 2007 through 2020

	Coal				Combined Cycle				Combustion Turbine				Diesel				Hydroelectric				Nuclear				Other			
Jan-Sep	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7.0%	8.4%	2.5%	82.2%	2.2%	5.2%	1.3%	91.2%	4.6%	2.3%	2.1%	91.0%	10.8%	0.7%	1.8%	86.7%	1.3%	5.4%	1.6%	91.8%	1.1%	3.8%	0.3%	94.7%	6.0%	7.2%	2.8%	83.9%
2008	7.9%	6.3%	2.4%	83.3%	2.1%	5.0%	1.4%	91.5%	3.0%	3.9%	1.9%	91.2%	9.8%	1.2%	1.2%	87.9%	1.6%	6.8%	1.7%	89.9%	0.9%	5.2%	0.6%	93.3%	4.2%	8.7%	2.6%	84.4%
2009	6.7%	7.1%	3.6%	82.6%	3.4%	5.1%	3.5%	88.0%	1.5%	2.7%	2.1%	93.8%	6.7%	0.3%	1.2%	91.8%	2.1%	8.9%	2.3%	86.7%	4.2%	4.2%	0.7%	90.9%	3.4%	7.9%	5.0%	83.7%
2010	7.8%	7.8%	4.2%	80.2%	2.6%	6.0%	3.1%	88.3%	2.0%	2.0%	1.6%	94.4%	4.7%	0.6%	0.8%	93.9%	0.8%	8.4%	2.1%	88.8%	1.9%	4.4%	0.5%	93.1%	5.0%	8.3%	3.5%	83.3%
2011	8.7%	8.1%	4.0%	79.3%	2.4%	7.0%	2.1%	88.5%	2.0%	3.2%	1.5%	93.2%	3.8%	0.0%	1.9%	94.3%	1.6%	13.2%	2.0%	83.2%	2.2%	5.8%	1.5%	90.5%	5.1%	8.1%	3.0%	83.8%
2012	7.3%	7.5%	5.8%	79.3%	2.5%	6.4%	1.8%	89.3%	2.0%	2.4%	1.5%	94.1%	3.9%	0.1%	1.7%	94.4%	3.5%	4.9%	1.8%	89.8%	1.4%	6.1%	0.9%	91.6%	4.8%	8.3%	4.7%	82.2%
2013	8.5%	9.4%	4.4%	77.6%	1.9%	8.5%	2.6%	87.0%	5.3%	3.1%	1.3%	90.2%	5.5%	0.3%	1.4%	92.8%	2.1%	6.5%	1.6%	89.7%	1.2%	5.6%	0.8%	92.4%	7.5%	9.2%	3.7%	79.6%
2014	10.0%	8.2%	5.2%	76.5%	2.8%	8.7%	2.1%	86.4%	7.7%	3.3%	1.4%	87.5%	14.0%	0.5%	2.3%	83.2%	2.0%	8.9%	3.0%	86.1%	1.8%	5.9%	0.9%	91.5%	7.1%	12.9%	5.9%	74.1%
2015	8.1%	7.7%	4.0%	80.1%	2.1%	8.3%	1.7%	87.9%	2.9%	4.1%	1.7%	91.3%	8.4%	0.4%	2.3%	88.9%	2.3%	7.9%	1.5%	88.3%	1.2%	4.9%	1.3%	92.7%	6.6%	15.3%	4.2%	73.9%
2016	8.7%	7.9%	5.9%	77.5%	3.0%	8.6%	1.7%	86.7%	2.2%	4.3%	1.9%	91.6%	5.4%	0.2%	2.5%	91.9%	2.1%	6.7%	2.7%	88.4%	2.1%	4.6%	1.1%	92.2%	5.2%	16.5%	3.8%	74.5%
2017	10.1%	8.1%	6.6%	75.3%	1.9%	7.9%	1.6%	88.6%	1.2%	3.9%	1.7%	93.2%	5.8%	0.2%	1.7%	92.3%	2.2%	5.3%	2.9%	89.6%	0.6%	5.0%	0.6%	93.9%	4.3%	8.5%	5.0%	82.2%
2018	10.6%	9.6%	6.8%	73.0%	1.5%	7.9%	1.2%	89.4%	2.0%	4.2%	1.5%	92.4%	6.2%	0.9%	2.7%	90.2%	2.2%	5.3%	3.1%	89.4%	0.8%	4.5%	0.5%	94.2%	4.0%	8.2%	8.1%	79.8%
2019	8.4%	7.8%	8.4%	75.3%	1.6%	7.9%	1.7%	88.8%	1.5%	5.4%	1.6%	91.5%	7.3%	1.0%	2.3%	89.3%	1.4%	5.4%	3.6%	89.7%	0.9%	4.6%	0.9%	93.5%	3.8%	9.9%	6.5%	79.7%
2020	1.6%	7.9%	1.7%	88.8%	1.5%	5.4%	1.6%	91.5%	7.3%	1.0%	2.3%	89.3%	1.4%	5.4%	3.6%	89.7%	0.9%	4.6%	0.9%	93.5%	3.8%	9.9%	6.5%	79.7%	3.8%	6.8%	4.1%	85.2%

Generator Forced Outage Rates

The most fundamental forced outage rate metric is the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[132] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd in the first nine months of 2020 was 6.3 percent, an increase from 6.0 percent in the first nine months of 2019. Figure 5-13 shows the average EFORd since 1999 for all units in PJM.[133]

132 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.
133 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2019 State of the Market Report for PJM*, Appendix A: "PJM Overview" for details.

Figure 5-13 Trends in the equivalent demand forced outage rate (EFORd): 1999 through 2020

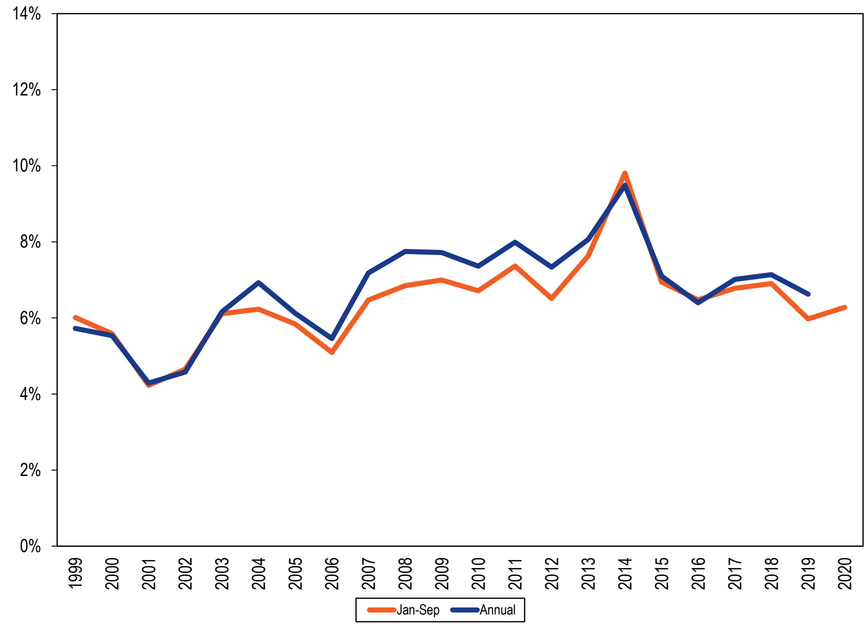


Table 5-27 shows the class average EFORd by unit type.

Table 5-27 EFORd by unit type: January through September, 2007 through 2020

	Jan-Sep													
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	7.9%	8.9%	8.2%	9.2%	10.8%	9.6%	10.8%	12.5%	9.5%	10.6%	12.7%	13.5%	11.8%	9.7%
Combined Cycle	3.7%	3.5%	4.8%	3.6%	3.1%	3.1%	2.6%	4.6%	2.8%	3.6%	2.4%	2.2%	2.0%	4.1%
Combustion Turbine	11.2%	11.3%	9.1%	9.1%	7.9%	6.5%	10.5%	17.7%	9.9%	5.3%	5.0%	6.4%	5.1%	4.1%
Diesel	12.3%	10.8%	8.8%	6.7%	9.8%	5.1%	6.1%	15.0%	9.7%	7.3%	7.1%	6.8%	8.0%	7.4%
Hydroelectric	1.9%	2.5%	2.7%	1.3%	2.2%	5.1%	3.2%	3.1%	3.1%	2.9%	3.1%	2.8%	1.7%	4.9%
Nuclear	1.2%	1.0%	4.3%	2.1%	2.4%	1.5%	1.3%	2.0%	1.2%	2.3%	0.6%	0.8%	1.0%	1.3%
Other	10.2%	9.6%	8.5%	7.9%	9.2%	8.3%	12.2%	13.6%	13.1%	9.8%	12.6%	9.5%	9.4%	16.7%
Total	6.5%	6.8%	7.0%	6.7%	7.4%	6.5%	7.6%	9.8%	6.9%	6.5%	6.8%	6.9%	6.0%	6.3%

Other Forced Outage Rate Metrics

Under the capacity performance modifications to RPM, effective with the 2018/2019 Delivery Year, neither XEFORd nor EFORp are relevant.

Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[134] On a system wide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).

PJM EFOF was 4.0 percent in the first nine months of 2020. This means there was 4.0 percent lost availability because of forced outages. Table 5-28 shows that forced outages for boiler tube leaks, at 13.6 percent of the systemwide EFOF, were the largest single contributor to EFOF.

134 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

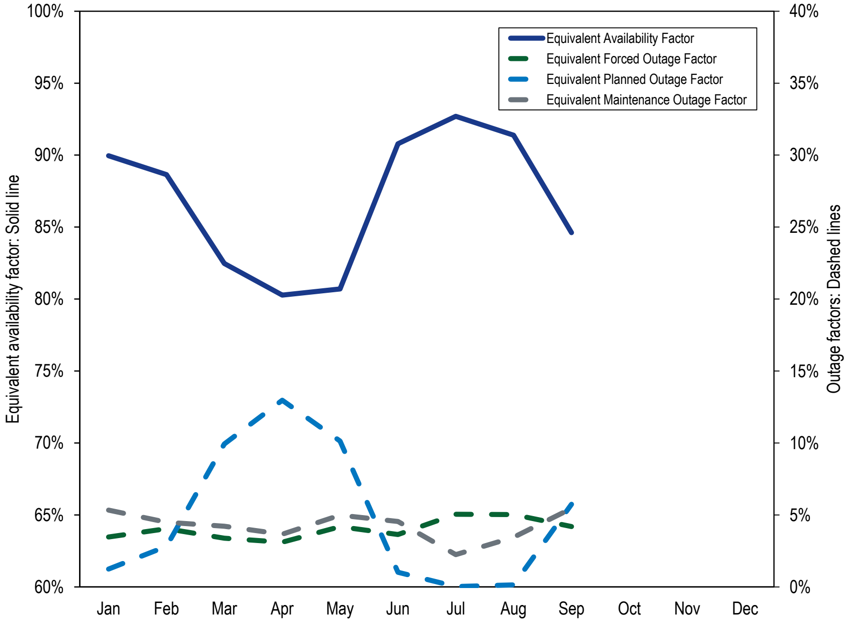
Table 5-28 Contribution to EFOF by unit type by cause: January through September, 2020

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	23.8%	1.8%	0.0%	0.0%	0.0%	0.0%	7.0%	13.6%
Electrical	2.6%	38.3%	14.0%	5.9%	6.2%	0.0%	1.9%	8.9%
Miscellaneous (Pollution Control Equipment)	12.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.1%	6.3%
High Pressure Turbine	10.9%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	5.7%
Catastrophe	1.8%	6.9%	1.7%	0.1%	54.4%	0.0%	6.5%	5.4%
Unit Testing	2.9%	3.9%	9.2%	25.9%	16.5%	0.5%	13.1%	5.4%
Generator	0.7%	18.6%	0.3%	5.1%	1.0%	4.9%	6.5%	4.7%
Controls	2.8%	0.8%	1.2%	9.7%	2.2%	0.0%	16.4%	4.0%
Feedwater System	6.5%	1.0%	0.0%	0.0%	0.0%	4.4%	1.0%	4.0%
Boiler Air and Gas Systems	3.4%	0.0%	0.0%	0.0%	0.0%	0.0%	16.2%	3.9%
Boiler Piping System	5.7%	2.2%	0.0%	0.0%	0.0%	0.0%	0.5%	3.4%
Miscellaneous (Steam Turbine)	0.8%	1.4%	0.0%	0.0%	0.0%	0.0%	16.2%	2.8%
Miscellaneous (Gas Turbine)	0.0%	4.8%	27.1%	0.0%	0.0%	0.0%	0.0%	2.5%
Boiler Fuel Supply from Bunkers to Boiler	4.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.5%	2.3%
Steam Generators and Steam System	0.0%	0.0%	0.0%	0.0%	0.0%	30.9%	0.0%	2.2%
Wet Scrubbers	3.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%
Economic	3.2%	0.1%	0.2%	3.0%	4.4%	0.0%	0.4%	2.0%
Auxiliary Systems	1.0%	1.8%	6.5%	0.0%	0.1%	0.0%	0.2%	1.3%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	0.0%	17.4%	0.0%	1.2%
All Other Causes	13.9%	18.2%	39.7%	50.4%	15.1%	41.9%	13.2%	18.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Performance by Month

On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-14.

Figure 5-14 Monthly generator performance factors: January through September, 2020



State of the Market Report for PJM

Volume 2: Detailed Analysis

Monitoring Analytics, LLC

Independent Market Monitor for PJM

2018

3.14.2019

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Capacity Market

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for 2018, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1]

Table 5-1 The capacity market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Not Competitive	
Market Performance	**Not Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[2] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as not competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. But the net CONE times B offer cap under the capacity performance design, in the absence of performance assessment hours, exceeds the competitive level and should be reevaluated for each BRA. In the 2021/2022 RPM Base Residual Auction, some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.
- Market performance was evaluated as not competitive. Although structural market power exists in the Capacity Market, a competitive outcome can result from the application of market power mitigation rules. The outcome of the 2021/2022 RPM Base Residual Auction was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, the inclusion of imports which are not substitutes for internal capacity resources, and the definition of the default offer cap.

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

2 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test.

3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[4]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for Delivery Years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each Delivery Year.[5] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the Delivery Year.[6] Also effective for the 2012/2013 Delivery Year, a Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant Delivery Year.[7]

The 2018/2019 RPM Third Incremental Auction, the 2021/2022 RPM Base Residual Auction, the 2019/2020 RPM Second Incremental Auction, and the 2020/2021 RPM First Incremental Auction were conducted in 2018.

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[8] For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM will procure two product types, Capacity Performance and Base Capacity. PJM also procured Capacity Performance resources in two transition auctions for the 2016/2017 and 2017/2018 Delivery Years. Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the Delivery Year.[9] Effective for the 2018/2019 through the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint are established for each modeled LDA. These maximum quantities are set for reliability purpose to limit the quantity procured of the less available products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. The Capacity Performance (CP) Transition Incremental Auctions (IAs) were held as part of a five year transition to a single capacity product type in the 2020/2021 Delivery Year. Participation in the CP Transition IAs was voluntary. If a resource cleared a CP Transition IA and had a prior commitment for the relevant delivery year, the existing commitment was converted to a CP commitment, which is subject to the CP performance requirements and nonperformance charges. The Transition IAs were not designed to minimize the cost of purchasing Capacity Performance resources for the two delivery years and were not designed to maximize economic welfare for the two delivery years.

RPM prices are locational and may vary depending on transmission constraints.[10] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit

4 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
5 See 126 FERC ¶ 61,275 at P 86 (2009).
6 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
7 See 126 FERC ¶ 61,275 at P 88 (2009).
8 See 151 FERC ¶ 61,208 (2015).
9 See "PJM Manual 18: PJM Capacity Market," § 1.5 Transition to Capacity Performance, Rev. 41 (Jan. 1, 2019).
10 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** During 2018, RPM installed capacity increased 2,069.3 MW or 1.1 percent, from 183,882.4 MW on January 1 to 185,951.7 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2018, 40.2 percent was gas; 32.7 percent was coal; 17.6 percent was nuclear; 4.8 percent was hydroelectric; 3.4 percent was oil; 0.6 percent was wind; 0.4 percent was solid waste; and 0.3 percent was solar.
- **Market Concentration.** In the 2018/2019 RPM Third Incremental Auction, 2019/2020 RPM Second Incremental Auction, 2021/2022 RPM Base Residual Auction, and the 2020/2021 RPM First Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[11] Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[12 13 14]
- **Imports and Exports.** Of the 4,470.4 MW of imports in the 2021/2022 RPM Base Residual Auction, 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (47.1 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,798.7 MW for June 1, 2018, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2018/2019 Delivery Year (13,731.7 MW) less replacement capacity (2,933.0 MW).

Market Conduct

- **2018/2019 RPM Base Residual Auction.** Of the 473 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 (35.1 percent) were based on the technology specific default (proxy) ACR values and 53 (11.2 percent) were unit-specific offer caps. Of the 992 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 35 generation resources (3.5 percent).
- **2018/2019 RPM First Incremental Auction.** Of the 80 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 30 generation resources (37.5 percent), of which 18 (22.5 percent) were based on the technology specific default (proxy) ACR values and 12 (15.0 percent) were unit-specific offer caps. Of the 293 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for nine generation resources (3.1 percent).
- **2018/2019 RPM Second Incremental Auction.** Of the 68 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 23 generation resources (33.8 percent), of which 12 (17.6 percent) were based on the technology specific default (proxy) ACR values and 11 (16.2 percent) were unit-specific offer caps. Of the 344 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for five generation resources (1.5 percent).
- **2018/2019 RPM Third Incremental Auction.** Of the 211 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for five generation resources (2.4 percent), of which one

11 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).

12 See OATT Attachment DD § 6.5.

13 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).

14 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

(0.5 percent) was based on the technology specific default (proxy) ACR values and four (1.9 percent) were unit-specific offer caps. Of the 495 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for three generation resources (0.6 percent).

- **2019/2020 RPM Base Residual Auction.** Of the 505 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 212 generation resources (42.0 percent), of which 171 (33.9 percent) were based on the technology specific default (proxy) ACR values and 41 (8.1 percent) were unit-specific offer caps. Of the 1,003 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 25 generation resources (2.5 percent).
- **2019/2020 RPM First Incremental Auction.** Of the 81 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 28 generation resources (34.6 percent), of which 17 (21.0 percent) were based on the technology specific default (proxy) ACR values and 11 (13.6 percent) were unit-specific offer caps. Of the 382 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for six generation resources (1.6 percent).
- **2019/2020 RPM Second Incremental Auction.** Of the 72 generation resources that submitted Base Capacity offers, the MMU calculated unit specific offer caps for eight generation resources (11.1 percent). Of the 409 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for six generation resources (1.5 percent).
- **2020/2021 RPM Base Residual Auction.** Of the 1,114 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 14 generation resources (1.3 percent).
- **2020/2021 RPM First Incremental Auction.** Of the 397 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for eight generation resources (2.0 percent).
- **2021/2022 RPM Base Residual Auction.** Of the 1,132 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for eight generation resources (0.7 percent).
  — The conduct of some participants was determined to be not competitive.

Market Performance

- The 2018/2019 RPM Third Incremental Auction, the 2021/2022 RPM Base Residual Auction, the 2019/2020 RPM Second Incremental Auction, and the 2020/2021 RPM First Incremental Auction were conducted in 2018. The weighted average capacity price for the 2018/2019 Delivery Year is $172.09, including all RPM auctions for the 2018/2019 Delivery Year held 2018. The weighted average capacity price for the 2019/2020 Delivery Year is $112.63, including all RPM auctions for the 2019/2020 Delivery Year held through 2018.
- For the 2018/2019 Delivery Year, RPM annual charges to load are $11.0 billion.
- In the 2021/2022 RPM Base Residual Auction, market performance was determined to be not competitive as a result of noncompetitive offers that affected market results.

Reliability Must Run Service

- Of the seven companies (23 units) that have provided RMR service, two companies (seven units) filed to be paid for RMR service under the deactivation avoidable cost rate (DACR), the formula rate. The other five companies (16 units) filed to be paid for RMR service under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for 2018 was 7.2 percent, an increase from 7.1 percent for 2017.[15]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2018 was 83.2 percent, a decrease from 83.9 percent for 2017.

15 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as capacity resources in RPM. Data was downloaded from the PJM GADS database on February 1, 2019. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

- **Outages Deemed Outside Management Control (OMC).** In 2018, 1.2 percent of forced outages were classified as OMC outages.

Recommendations[16]

The MMU recognizes that PJM has implemented the Capacity Performance Construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance Construct addresses many of the MMU's recommendations. The MMU's recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[17]

Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant Delivery Year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[18] [19] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[20] [21] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)

16 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

17 151 FERC ¶ 61,208 (2015).

18 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).

19 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

20 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

21 See the *2017 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported 2017. Status: Not adopted.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[22] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[23] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Non-Performance Charge Rate. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the default offer cap. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed reserve margins, and other assumptions consistent with the annual IRM study. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that when expected H and B are not the same as the assumed levels used to calculate the default market seller offer cap of Net CONE times B, the offer cap be recalculated for each BRA using the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAH not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)

22 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

23 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

- The MMU recommends that there be an explicit requirement that capacity resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that RMR units recover all and only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules.

The MMU concludes that the 2021/2022 RPM Base Residual Auction results were not competitive as a result of offers above the competitive level by some market participants. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

The FERC approved PJM tariff defines the offer cap as Net CONE times B, rather than including the full logic supporting the definition of the offer cap under the capacity performance paradigm. If the tariff had defined the offer cap consistent with PJM's filing in the capacity performance matter, the offer cap would have been net ACR rather than Net CONE times B.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

The MMU found serious market structure issues, measured by the three pivotal supplier test results in the PJM Capacity Market in 2018. Explicit market power mitigation rules in the RPM construct only partially offset the underlying market structure issues in the PJM Capacity Market under RPM. In the 2021/2022 RPM Base Residual Auction, the default offer cap of net CONE times B exceeded the competitive offer for a number of resources. Some seasonal resources were paid additional make whole based on a failure of the market power rules to apply offer capping.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[24 25 26 27 28 29 30] In 2017 and 2018, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2. The capacity performance modifications to the RPM construct have significantly improved the capacity market and addressed many of the issues identified by the MMU. The MMU will continue to publish more detailed reports on the CP auctions which include more specific issues and suggestions for improvements.

The PJM markets have worked to provide incentives to entry and to retaining capacity. PJM had excess reserves of more than 9,000 MW on June 1, 2018, and will have excess reserves of more than 17,000 MW on June 1, 2019, based on current positions.[31] Capacity investments in PJM were financed by market sources. Of the 30,881.7 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2017/2018 delivery years, 22,419.7 MW (72.6 percent) were based on market funding. Of the 13,553.8 MW of additional capacity that cleared in RPM auctions for the 2018/2019 through 2021/2022 delivery years, 11,752.4 MW (86.7 percent) are based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

The issue of external subsidies emerged more fully in 2017 and 2018. The subsidies are not part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings, the Illinois ZEC legislation to subsidize the Quad Cities nuclear power plant, the request in Pennsylvania to subsidize the Three Mile Island nuclear power plant, the New Jersey legislation to subsidize the Salem and Hope Creek nuclear power plants, the potential U.S. DOE proposal to subsidize coal and nuclear power plants, and the request by FirstEnergy to the U.S. DOE for subsidies consistent with the DOE Grid Resilience Proposal, all originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. The proposed solution in all cases ignores the opportunity cost of subsidizing uneconomic units, which is the displacement of new resources and technologies that would otherwise be economic. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market-based mechanisms available to all market participants on a competitive basis and without discrimination.

24 See "Analysis of the 2017/2018 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf> (October 6, 2014).

25 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).

26 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).

27 See "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

28 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

29 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).

30 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

31 The calculated reserve margin for June 1, 2019, does not account for cleared buy bids that have not been used in replacement capacity transactions.

Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these subsidies.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market. The MMU calls this approach the Sustainable Market Rule (SMR).

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet.

Subsidies to specific resources that are uneconomic as a result of competition are an effort to reverse market outcomes with no commitment to a regulatory model and no attempt to mitigate negative impacts on competition. The unit specific subsidy model is inconsistent with the PJM market design and inconsistent with the market paradigm and constitutes a significant threat to both.

The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity.

Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value is calculated correctly.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

Price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus in the entire market.

The expected impact of the SMR design on the offers and clearing of renewable resources and nuclear plants would be from zero to insignificant. The competitive offers of renewables, based on the net ACR of current technologies, are likely to clear in the capacity market. The competitive offers of nuclear plants, based on net ACR, are likely to clear in the capacity market.

Cost of service resources have the option of using the existing FRR rules, which would allow regulated utilities to opt out of the capacity market. The expected impact of the SMR design on the offers and clearing of regulated cost of service resources that remained in the capacity market would be from zero to insignificant. The competitive offers of these resources, based on net ACR, are likely to clear in the capacity market.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed, but this can happen with a slightly longer lead time. If a shared goal is to reduce carbon output, a price on carbon is the market based solution. If a shared goal is increased renewables in addition to their carbon attributes, a common approach to RECs would be a market based solution. Fuel diversity has also been mentioned as an issue. Current fuel diversity is higher than ever in PJM. If there is an issue, the real issue is fuel security and not fuel diversity. Significant reliance on specific fuels, including nuclear, coal and gas means that markets are at risk from a significant disruption in any one fuel. If fuel security for gas is a concern, a number of issues should be considered including the reliability of the pipelines, the compatibility of the gas pipeline and the merchant generator business models, the degree to which electric generators have truly firm gas service and the need for a gas RTO to help ensure reliability.

As a result of the fact that demand side resources have contributed to price suppression in PJM capacity markets, the place of demand side in PJM should be reexamined. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.

Table 5-2 RPM related MMU reports: 2017 through 2018

Date	Name
January 11, 2017	Replacement Capacity http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MIC_Replacement_Capacity_Report_20170111.pdf
January 24, 2017	Summary of BRA Analysis Results: 2013/2014 - 2019/2020 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_BRA_Scenario_Results_Summary_20170124.pdf
January 30, 2017	IMM Answer re Amended Calpine MOPR Complaint Docket No. EL16-49-000 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_EL16-49_20170130.pdf
February 13, 2017	IMM Answer re Base Capacity Complaint Docket Nos. EL17-32 and EL17-36 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_Nos_EL17-32_EL17-36_20170213.pdf
February 24, 2017	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20170224.pdf
March 1, 2017	Incremental Auction Review http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_Incremental_Auction_Review_20170301.pdf
May 11, 2017	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligation_20170509.pdf
June 27, 2017	MMU Incremental Auction Recommendation - Package B http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_MMU_Package_B_Summary_20170627.pdf
June 27, 2017	Replacement Capacity Issues http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_Replacement_Capacity_Issues_20170627.pdf
August 30, 2017	IMM Answer re IMM MOPR Exemption Complaint Docket No. EL17-82 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_EL17-82_20170830.pdf
August 30, 2017	Incremental Auction Design Changes, Package B http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_Package_B_Executive_Summary_20170830.pdf
September 5, 2017	IMM Comments re PJM Deficiency Letter Compliance Docket No. ER17-775-002 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Comments_Docket_No_ER17-775-002_20170905.pdf
September 8, 2017	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligation_20170509.pdf
September 11, 2017	IMM CCPPSTF Proposal http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_CCPPSTF_Proposal_20170911.pdf
September 12, 2017	IMM Answer re Pleasants Transfer Docket No. EC17-88 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_EC17-88_20170912.pdf
October 17, 2017	Revised IMM MOPR-Ex Proposal for CCPPSTF http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_Letter_CCPPSTF_IM_%20Proposal_Summary_Revised_20171017.pdf
November 2, 2017	IMM MOPR-Ex Proposal for the CCPPSTF http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_CCPPSTF_Proposal_Summary_Revised_20171103.pdf
November 12, 2017	IMM MOPR-Ex Proposal for the CCPPSTF http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_CCPPSTF_Proposal_Summary_Revised_3_Redline_20171112.pdf
November 14, 2017	IMM Answer re MOPR Reforms Docket No. ER13-535 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_ER13-535_20171114.pdf
November 17, 2017	Analysis of 2020/2021 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf
December 12, 2017	IMM MOPR-Ex RPS Status http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_Special_Session_MOPR-Ex_RPS_Status_20171212.pdf
December 12, 2017	IMM MOPR-Ex Proposal Language - Revised http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_Special_Session_MOPR_Ex_Proposal_Language_Revised_20171212.pdf
December 14, 2017	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf
December 21, 2017	MOPR-Ex Proposal Language Revised - 2 http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MOPR-Ex_Proposal_Language_Revised_2_2017121.pdf

Table 5-2 RPM related MMU reports: 2017 through 2018 (continued)

Date	Name
December 21, 2017	MOPR-Ex Proposal Language - Revised 3 http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MOPR-Ex_Proposal_Language_Revised_3_20171213.pdf
December 21, 2017	IMM MOPR-Ex RPS Status Revisions http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_MOPR-Ex_RPS_Status_Revisions_20171214.pdf
December 21, 2017	MOPR-Ex Proposal http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_MOPR-Ex_Proposal_20171221.pdf
December 22, 2017	IMM Parameter Limited Schedule Matrix (Annual) http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Parameter_Limited_Schedule_Market_Notice_20171222.pdf
December 27, 2017	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligations_20171227.pdf
January 19, 2018	Analysis of Replacement Capacity for RPM Commitments http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_IASTF_Analysis_of_Replacement_Capacity_for_RPM_Commitments_20180119.pdf
January 25, 2018	MOPR-Ex Main Motion http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MRC_MOPR-Ex_Main_Motion_20180125.pdf
January 25, 2018	MOPR-Ex Alternate Proposal http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MRC_MOPR-Ex_Alternate_Proposal_20180125.pdf
January 25, 2018	MOPR-Ex Memo http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MRC_MOPR-Ex_Memo_20180125.pdf
February 23, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20180223.pdf
March 9, 2018	Generation Additions and Retirements in the PJM Capacity Market: MW and Funding Sources http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Generation_Additions_and_Retirements_in_the_PJM_Capacity_Market_20180309.pdf
April 11, 2018	IMM Comments re Base Capacity Complaint Docket Nos. EL17-32 and EL17-36 http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Comments_Docket_No_EL17-32_EL17-36_20180411.pdf
May 9, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_RPM_Must_Offer_Obligations_20180509.pdf
June 1, 2018	IMM CONE CT Study Results http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MIC_Quadrennial_Review_Special_Session_CONE_CT_Study_Results_20180601.pdf
June 7, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_RPM_Must_Offer_Obligations_20180706.pdf
June 13, 2018	IMM Post Technical Conf. Comments re Base Capacity Complaint Docket No. EL17-31, -36 http://www.monitoringanalytics.com/Filings/2018/IMM_Post_Tech_Conf_Comments_Docket_No_EL17-32_-36_20180713.pdf
June 22, 2018	IMM CONE CT Study Results http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MIC_Quadrennial_Review_Special_Session_CONE_CT_Study_Results_20180601.pdf
August 24, 2018	Analysis of the 2021/2022 RPM Base Residual Auction - Revised http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf
August 24, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years (PDF) http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_RPM_Must_Offer_Obligations_20180824.pdf
September 26, 2018	MOPR/FRR Sensitivity Analyses of the 2021/2022 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2018/IMM_MOPR_FRR_Sensitivity_Analyses_Report_20180926.pdf
October 2, 2018	IMM Brief re Capacity Market Investigation Docket Nos. EL16-49-000,ER18-1314-000,-001, EL18-178 http://www.monitoringanalytics.com/Filings/2018/IMM_Brief_Docket_No_EL16-49_EL18-178_ER18-1314_20181002.pdf
October 22, 2018	IMM Comments re NJ ZECs Docket No. EO18080899 http://www.monitoringanalytics.com/Filings/2018/IMM_Comments_Docket_No_EO18080899_20181022.pdf
October 23, 2018	IMM Notice of Withdrawal re Fairless MOPR Docket No. EL17-82 http://www.monitoringanalytics.com/Filings/2018/IMM_Notice_of_Withdrawal_Docket_No_EL17-82_20181023.pdf
October 31, 2018	IMM Summary of Position re Capacity Market Investigation Docket Nos. EL18-178, ER18-1314-000,-001, EL16-49 http://www.monitoringanalytics.com/Filings/2018/IMM_Summary_of_Position_Docket_No__EL18-178_ER18-1314_EL16-49.pdf
November 6, 2018	IMM Brief re Capacity Market Investigation Docket Nos. EL18-178, ER18-1314-000,-001, EL16-49 http://www.monitoringanalytics.com/Filings/2018/IMM_Reply_Brief_Docket_No_EL18-178_ER18-1314-000_001_EL16-49_20181106.pdf
November 19, 2018	IMM Protest re Quadrennial Review Docket No. ER19-105 http://www.monitoringanalytics.com/Filings/2018/IMM_Protest_Docket_No_ER19-105_20181119.pdf
November 19, 2018	IMM Protest re Maintenance Adders Docket No. ER19-210 http://www.monitoringanalytics.com/Filings/2018/IMM_Protest_Docket_No_ER19-210_20181119.pdf
December 21, 2018	IMM Answer and Motion for Leave to Answer re VOM Complaint and Maintenance Adder Docket No. EL19-8, ER19-210 http://www.monitoringanalytics.com/Filings/2018/IMM_Answer_Docket_Nos_EL19-8_ER19-210_20181221.pdf
December 31, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20181231.pdf

Installed Capacity

On January 1, 2018, RPM installed capacity was 183,882.4 MW (Table 5-3).[32] Over the next twelve months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 185,951.7 MW on December 31, 2018, an increase of 2,069.3 MW or 1.1 percent from the January 1 level.[33 34] The 2,069.3 MW increase was the result of new or reactivated generation (8,381.6 MW), a decrease in exports (224.9 MW), and uprates (526.3 MW), offset by deactivations (5,596.9 MW), a decrease in imports (1,323.3 MW), and derates (143.3 MW).

At the beginning of the new delivery year on June 1, 2018, RPM installed capacity was 183,386.2 MW, a decrease of 1,658.3 MW or 0.9 percent from the May 31, 2018 level.

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2018

	01-Jan-18		31-May-18		01-Jun-18		31-Dec-18	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	65,144.0	35.4%	64,992.8	35.1%	61,033.1	33.3%	60,763.4	32.7%
Gas	67,811.4	36.9%	69,256.9	37.4%	71,241.8	38.8%	74,716.8	40.2%
Hydroelectric	8,856.2	4.8%	8,819.0	4.8%	8,888.2	4.8%	8,888.2	4.8%
Nuclear	33,163.5	18.0%	33,242.2	18.0%	33,292.2	18.2%	32,684.5	17.6%
Oil	6,587.2	3.6%	6,429.4	3.5%	6,388.2	3.5%	6,388.2	3.4%
Solar	374.0	0.2%	374.0	0.2%	589.1	0.3%	640.0	0.3%
Solid waste	809.4	0.4%	786.4	0.4%	795.3	0.4%	712.3	0.4%
Wind	1,136.7	0.6%	1,143.8	0.6%	1,158.3	0.6%	1,158.3	0.6%
Total	183,882.4	100.0%	185,044.5	100.0%	183,386.2	100.0%	185,951.7	100.0%

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2018, as well as the expected installed capacity for the next three delivery years, based on the results of all auctions held through December 31, 2018.[35] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 33.3 percent on June 1, 2018 and is projected to decrease to 28.2 percent by June 1, 2021. The share of gas increased from 29.1 percent in 2007 to 38.9 percent in 2018 and is projected to increase to 50.3 percent in 2021.

32 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

33 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM auctions.

34 Wind resources accounted for 1,158.3 MW, and solar resources accounted for 640.0 MW of installed capacity in PJM on December 31, 2018. PJM administratively reduces the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind and solar resources will be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," § Appendix B: Calculating Capacity Values for Wind and Solar Capacity Resources, Rev. 12 (Jan. 1, 2017).

35 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2021

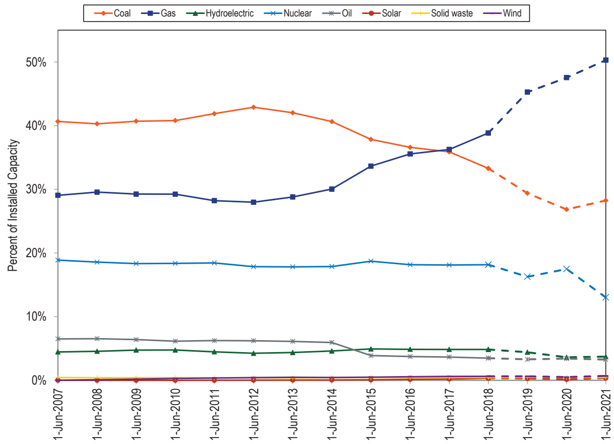


Table 5-4 shows the RPM installed capacity on January 1, 2018, through December 31, 2018, for the top five generation capacity resource owners, excluding FRR committed MW.

Table 5-4 Installed capacity by parent company: January 1, May 31, June 1, and December 31, 2018

	01-Jan-18			31-May-18			01-Jun-18			30-Sep-18			31-Dec-18		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Exelon Corporation	23,426.0	13.9%	1	23,423.1	13.8%	1	23,426.8	13.9%	1	22,819.1	13.4%	1	22,819.1	13.3%	1
Dominion Resources, Inc.	21,098.5	12.5%	2	20,467.3	12.0%	2	20,610.8	12.2%	2	20,527.8	12.1%	2	19,851.9	11.6%	2
FirstEnergy Corp.	15,840.6	9.4%	3	14,959.5	8.8%	4	14,943.3	8.9%	3	14,651.9	8.6%	3	14,644.0	8.5%	3
NRG Energy, Inc.	15,756.5	9.3%	4	15,745.0	9.3%	3	13,937.3	8.3%	4	13,810.5	8.1%	4	5,116.5	3.0%	10
Dynegy Inc.	12,307.4	7.3%	5												
Talen Energy Corporation	11,527.7	6.8%	6	11,121.2	6.5%	6	10,959.3	6.5%	6	10,959.3	6.4%	6	10,959.3	6.4%	5
Vistra Energy Corp.				13,388.2	7.9%	5	12,115.0	7.2%	5	12,133.3	7.1%	5	12,082.3	7.0%	4

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and December 31, 2018

	01-Jan-18		31-May-18		01-Jun-18		31-Dec-18	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	151,193.8	82.2%	152,037.2	82.2%	150,108.7	81.9%	153,668.5	82.6%
Nonmarket	32,688.6	17.8%	33,007.3	17.8%	33,277.5	18.1%	32,283.2	17.4%
Total	183,882.4	100.0%	185,044.5	100.0%	183,386.2	100.0%	185,951.7	100.0%

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2018, to December 31, 2018, by funding type.

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[36] The FDI_c is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type i. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. The fuel type categories used in the calculation of the FDI_c are the eight fuel sources in Table 5-3. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[37] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004

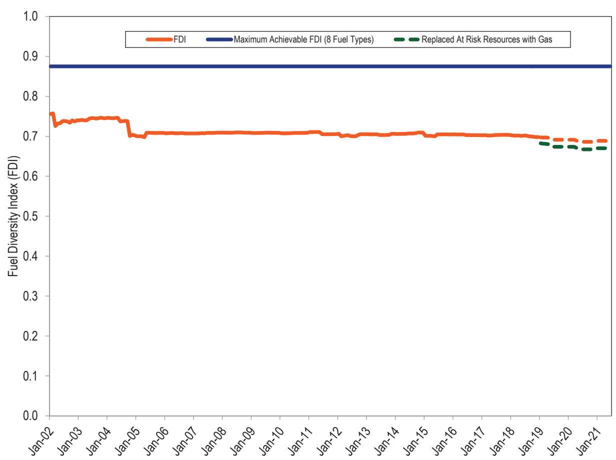
36 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

37 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 State of the Market Report for PJM* for additional details.

with the expansion into the ComEd, AEP, and Dayton Power & Light control zones.[38] The average FDI_c for 2018 decreased 0.3 percent from 2017. Figure 5-2 also includes the expected FDI_c through June 2021 based on cleared RPM auctions. The expected FDI_c is indicated in Figure 5-2 by the dashed orange line.

The FDI_c was used to measure the impact of potential retirements of resources that the MMU has identified as being at risk of retirement. There were 18 capacity resources with installed capacity totaling 14,954 MW identified as being at risk of retirement. The dashed green line in Figure 5-2 shows the FDI_c calculated assuming that the capacity from these 18 resources that has cleared in a RPM auction is replaced by gas generation. The FDI_c under these assumptions would decrease by 0.018 (2.6 percent) on average from the expected FDI_c for the period January 1, 2019, through June 1, 2021.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 1, 2021



RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward-looking, annual, locational market, with a must-offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[39] In 2018, the 2018/2019 RPM Third Incremental Auction, the 2021/2022 RPM Base Residual Auction, the 2019/2020 RPM Second Incremental Auction, and the 2020/2021 RPM First Incremental Auction were conducted.

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2017/2018 Delivery Year. The 19,726.8 MW increase was the result of new generation capacity resources (23,479.1 MW), reactivated generation capacity resources (971.0 MW), uprates (6,431.6 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (3,545.5 MW), a net decrease in capacity exports (2,519.2 MW), offset by deactivations (31,959.6 MW) and derates (3,369.0 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) for June 1, 2016, through June 1, 2021, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the final peak load forecast for the given delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction using the cleared buy bid capacity. The calculated reserve margins for June 1, 2019, and June 1, 2020, do not account for cleared buy bids that have not been used in replacement capacity transactions. Without an approved early replacement transaction requested for defined physical reasons, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day.

38 See the *2018 State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.

39 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Future Changes in Generation Capacity[40]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2017/2018 Delivery Year, internal installed capacity decreased by 4,446.9 MW after accounting for new capacity resources, reactivations, and uprates (30,881.7 MW) and capacity deactivations and derates (35,328.6 MW).

For the current and future delivery years (2018/2019 through 2021/2022), new generation capacity is defined as capacity that cleared an RPM auction for the first time in the specified DY. Looking ahead, based on expected completion rates of cleared new generation capacity (10,654.1 MW) and pending deactivations (10,950.2 MW), PJM capacity is expected to decrease by 296.1 MW for the 2018/2019 through 2021/2022 Delivery Years.

New generation capacity from the 2007/2008 DY through the 2017/2018 DY totaled 23,479.1 MW (76.0 percent of all additions), with 16,450.0 MW from market funding and 7,029.1 MW from nonmarket funding. Reactivated generation capacity from the 2007/2008 DY through the 2017/2018 DY totaled 971.0 MW (3.1 percent of all additions), with 896.0 MW from market funding and 75.0 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 DY through the 2017/2018 DY totaled 6,431.6 MW (20.8 percent of all additions), with 5,073.7 MW from market funding and 1,357.9 MW from nonmarket funding. In summary, of the 30,881.7 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2017/2018 delivery years, 22,419.7 MW (72.6 percent) were based on market funding.

Of the 8,159.3 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2018/2019 through 2021/2022 delivery years, that are not yet in service, 6,536.3 MW have market funding and 1,623.0 MW have nonmarket funding. Applying the historical completion rates, 4,045.8 MW, or 61.9 percent, of the market funded projects are expected to go into service. Similarly, 1,163.2 MW, or 71.7 percent, of nonmarket funded projects are expected to go into service. Together, 5,209.1 MW, or 63.8 percent, of new generation capacity that cleared MW in RPM and are not yet in service are expected to go into service through the 2021/2022 Delivery Year.

Of the 5,394.5 MW of the additional generation capacity that cleared in RPM auctions for the 2018/2019

Table 5-6 Generation capacity changes: 2007/2008 to 2018/2019

	ICAP (MW)									
	Total at June 1	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	163,659.4	372.8	156.8	1,238.1	0.0	(96.7)	143.9	389.5	617.8	519.8
2008/2009	164,179.2	812.9	6.3	1,108.9	0.0	871.1	(1,702.9)	615.0	612.4	3,274.7
2009/2010	167,453.9	188.1	13.0	370.4	0.0	68.6	735.9	472.4	171.2	(739.4)
2010/2011	166,714.5	1,751.2	16.0	587.3	11,821.6	187.2	(427.0)	1,439.2	286.9	13,064.2
2011/2012	179,778.7	3,095.0	138.0	553.8	3,607.4	262.7	(1,374.5)	2,758.5	313.0	5,959.9
2012/2013	185,738.6	266.4	79.0	364.5	2,680.0	841.8	(17.3)	4,152.1	267.6	(170.7)
2013/2014	185,567.9	264.7	20.9	397.9	0.0	2,217.2	21.6	4,027.7	421.9	(1,570.5)
2014/2015	183,997.4	3,036.0	0.0	480.4	0.0	859.1	73.3	11,442.9	221.0	(7,361.7)
2015/2016	176,635.7	5,497.8	0.0	409.0	0.0	787.6	285.1	863.4	156.4	5,389.5
2016/2017	182,025.2	2,537.8	537.0	589.8	0.0	(1,011.1)	(36.4)	1,447.3	167.8	1,074.8
2017/2018	183,100.0	5,656.4	4.0	331.5	0.0	(1,442.0)	(220.9)	4,351.6	133.0	286.2
2018/2019	183,386.2									
Total		23,479.1	971.0	6,431.6	18,109.0	3,545.5	(2,519.2)	31,959.6	3,369.0	19,726.8

Sources of Funding[41]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

40 For more details on future changes in generation capacity, see "Generation Additions and Retirements in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2020/2021," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Generation_Additions_and_Retirements_in_the_PJM_Capacity_Market_20180309.pdf> (March 9, 2018).

41 For more details on sources of funding for generation capacity, see "Generation Additions and Retirements in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2020/2021," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Generation_Additions_and_Retirements_in_the_PJM_Capacity_Market_20180309.pdf> (March 9, 2018).

through 2021/2022 delivery years and are already in service, 5,216.1 MW (96.7 percent) are based on market funding. In summary, 11,752.4 MW (86.7 percent) of the additional generation capacity (5,216.1 MW in service and 6,536.3 MW not yet in service) that cleared in RPM auctions for the 2018/2019 through 2021/2022 delivery years are based on market funding. Capacity additions based on nonmarket funding are 1,801.4 MW (13.3 percent) of proposed generation that cleared at least one RPM auction for the 2018/2019 through 2021/2022 delivery years.

- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2018 PJM EDCs and their affiliates maintained a large market share of load obligations

Table 5-7 RPM reserve margin: June 1, 2016 to June 1, 2021[42 43]

	Generation and DR RPM Committed Less Deficiency UCAP (MW)	Forecast Peak Load	FRR Peak Load	PRD	RPM Peak Load	IRM	Pool Wide Average EFORd	Generation and DR RPM Committed Less Deficiency ICAP (MW)	Reserve Margin	Reserve Margin in Excess of IRM: Percent	Reserve Margin in Excess of IRM: ICAP (MW)	Projected Replacement Capacity using Cleared Buy Bids UCAP (MW)	Projected Reserve Margin
01-Jun-16	160,883.3	152,356.6	12,511.6	0.0	139,845.0	16.4%	5.91%	170,988.7	22.3%	5.9%	8,209.2	0.0	22.3%
01-Jun-17	163,872.0	153,230.1	12,837.5	0.0	140,392.6	16.6%	5.94%	174,220.7	24.1%	7.5%	10,522.9	0.0	24.1%
01-Jun-18	161,242.6	152,407.9	12,732.9	0.0	139,675.0	16.1%	6.07%	171,662.5	22.9%	6.8%	9,499.8	0.0	22.9%
01-Jun-19	167,892.2	151,643.5	12,284.2	0.0	139,359.3	16.0%	6.08%	178,760.9	28.3%	12.3%	17,104.1	3,988.8	25.2%
01-Jun-20	165,943.4	152,245.4	12,065.2	558.0	139,622.2	15.9%	5.97%	176,479.2	26.4%	10.5%	14,657.1	3,446.6	23.8%
01-Jun-21	160,795.3	152,647.4	12,107.1	510.0	140,030.3	15.8%	5.89%	170,858.9	22.0%	6.2%	8,703.8	0.0	22.0%

Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.

under RPM, together totaling 59.8 percent (Table 5-8), down from 63.6 percent on June 1, 2017. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 40.2 percent, up from 36.4 percent on June 1, 2017. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007 to June 1, 2018 is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 59.8 percent on June 1, 2018. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 40.2 percent on June 1, 2018. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

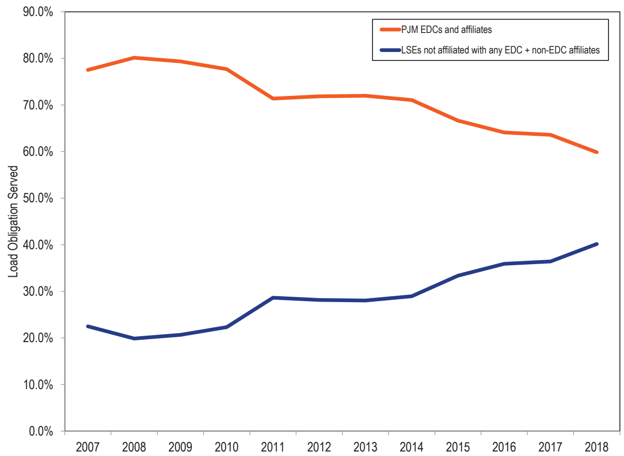
42 The calculated reserve margins in this table do not include EE on the supply side or the EE add back on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.

43 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

Table 5-8 Capacity market load obligation served: June 1, 2018

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	50,211.2	32,092.5	24,393.1	6,719.4	12,183.7	37,165.1	15,549.5	178,314.4
Percent of total obligation	28.2%	18.0%	13.7%	3.8%	6.8%	20.8%	8.7%	100.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2018



Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays for the transmission system through firm transmission charges and pays for congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA is equal to the Unforced Capacity imported into the LDA, based on the results of the Base Residual Auction and Incremental Auctions, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

For LDAs in which the RPM auctions for a delivery year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment or charge equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs.

In the 2021/2022 RPM Base Residual Auction, EMAAC had 4,352.6 MW of CTRs with a total value of $40,877,295, PSEG had 4,990.5 MW of CTRs with a total value of $70,238,159, ATSI had 6,402.8 MW of CTRs with a total value of $73,219,252, ComEd had 1,527.9 MW of CTRs with a total value of $30,978,820, and BGE had 5,125.6 MW of CTRs with a total value of $112,812,971.

EMAAC had 40.0 MW of customer funded ICTRs with a total value of $375,658, PSEG had 41.0 MW of customer funded ICTRs with a total value of $577,050, BGE had 65.7 MW of customer funded ICTRs with a total value of $6,734,907, and ComEd had 1,097.0 MW of customer funded ICTRs with a total value of $22,242,498.

EMAAC had 948.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $8,903,095. PSEG had 499.4 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $7,605,806. BGE had 306.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $8,180,931.

Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2018/2019 RPM Third Incremental Auction, the 2019/2020 RPM Second Incremental Auction, the 2021/2022 RPM Base Residual Auction, and the 2020/2021 RPM First Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS).[44] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and

44 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.

the submitted sell offer, absent mitigation, increased the market clearing price.[45 46 47]

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-9 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSIx). The RSIx is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSIx is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSIx is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

45 See OATT Attachment DD § 6.5.

46 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).

47 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for planned generation capacity resource and creating a new definition for existing generation capacity resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a planned generation capacity resource. See 134 FERC ¶ 61,065 (2011).

Table 5-9 RSI results: 2018/2019 through 2021/2022 RPM Auctions[48]

RPM Markets	$RSI_{1,\,1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2018/2019 Base Residual Auction				
RTO	0.81	0.65	125	125
EMAAC	0.59	0.16	12	12
ComEd	1.11	0.02	4	4
2018/2019 First Incremental Auction				
RTO	0.51	0.23	32	32
EMAAC	0.00	0.00	2	2
ComEd	0.00	0.00	1	1
2018/2019 Second Incremental Auction				
RTO	0.64	0.87	44	9
EMAAC	0.25	0.06	5	5
2018/2019 Third Incremental Auction				
RTO	0.88	0.65	71	71
EMAAC	0.00	0.00	3	3
2019/2020 Base Residual Auction				
RTO	0.81	0.66	131	131
EMAAC	0.79	0.23	6	6
ComEd	0.74	0.12	6	6
BGE	0.00	0.00	1	1
2019/2020 First Incremental Auction				
RTO	0.63	0.50	53	53
EMAAC	0.00	0.00	5	5
2019/2020 Second Incremental Auction				
RTO	0.61	0.48	38	38
BGE	0.00	0.00	1	1
2020/2021 Base Residual Auction				
RTO	0.81	0.69	119	119
MAAC	0.67	0.77	24	24
EMAAC	0.45	0.18	21	21
ComEd	0.47	0.20	14	14
DEOK	0.00	0.00	1	1
2020/2021 First Incremental Auction				
RTO	0.47	0.42	47	47
2021/2022 Base Residual Auction				
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3

Locational Deliverability Areas (LDAs)

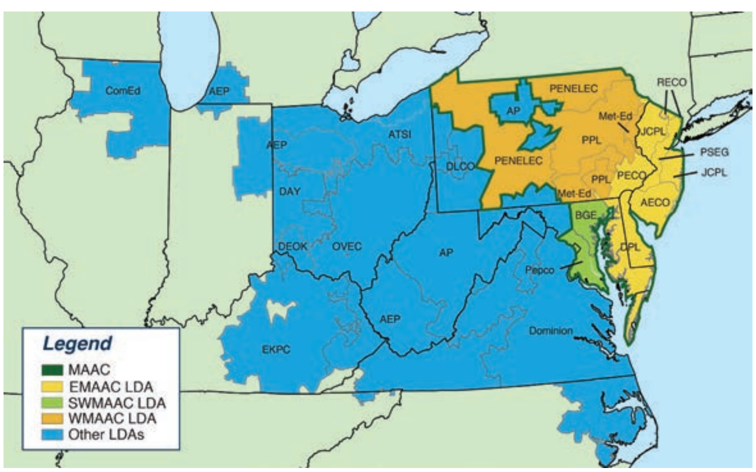
Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a Delivery Year if the Capacity Emergency Transfer Limit (CETL) is less than

48 The RSI shown is the lowest RSI in the market.

1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[49] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[50] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement are established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, are established for each modeled LDA.[51] Effective for the 2018/2019 through the 2019/2020 Delivery Years, Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, are established for each modeled LDA.

Locational Deliverability Areas are shown in Figure 5-4, Figure 5-5 and Figure 5-6.

Figure 5-4 Map of locational deliverability areas



49 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
50 OATT Attachment DD § 5.10 (a) (ii).
51 146 FERC ¶ 61,052 (2014).

Figure 5-5 Map of RPM EMAAC subzonal LDAs

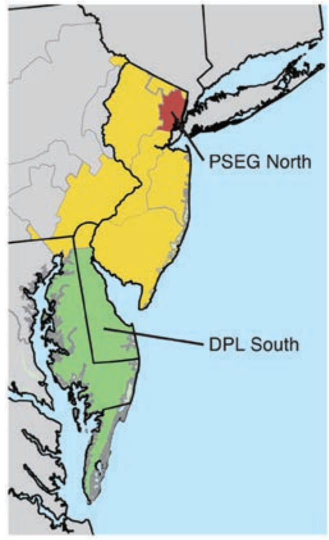
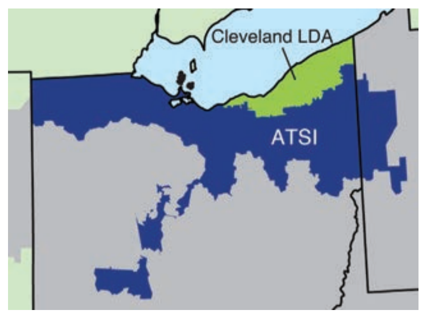


Figure 5-6 Map of RPM ATSI subzonal LDA



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[52]

The PJM market rules should not create inappropriate barriers to either the import or export of capacity. The market rules in other balancing authorities should also not create inappropriate barriers to the import or export

52 OATT Attachment DD § 5.6.6(b).

of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. While pseudo ties were a step toward this goal, pseudo ties alone are not adequate to ensure deliverability. Pseudo ties create potential issues in the exporting area and do not ensure deliverability into the importing area. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the Day-Ahead Energy Market should be clarified for both internal and external resources.

For the 2017/2018 through the 2019/2020 Delivery Year, Capacity Import Limits (CILs) are established for each of the five external source zones and the overall PJM region to account for the risk that external generation resources may not be able to deliver energy during the relevant delivery year due to the curtailment of firm transmission by third parties.[53] Capacity Market Sellers may request an exception to the CIL for an external generation resource by committing that the resource will be pseudo tied prior to the start of the relevant delivery year, by demonstrating that it has long-term firm transmission service confirmed on the complete transmission path from the resource to PJM, and by agreeing to be subject to the same RPM must offer requirement as internal PJM generation resources.

Effective June 9, 2015, an external generation capacity resource must obtain an exception to the CILs to be eligible to offer as a Capacity Performance Resource, which means that effective with the 2020/2021 delivery year, CILs are no longer defined as an RPM parameter.[54]

As shown in Table 5-10, of the 4,470.4 MW of imports offered in the 2021/2022 RPM Base Residual Auction, 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (47.1 percent) were from MISO.

Importing Capacity

Existing External Generation Capacity Resource

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[55] [56] Firm transmission service from the unit to the border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point to point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; 12 months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; a letter of nonrecallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Energy Market.[57]

To avoid balancing market deviations, any offer accepted in the Day-Ahead Energy Market must be scheduled to physically flow in the Real-Time Energy Market. When submitting the real-time energy market transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. External capacity transactions must designate the transaction as such when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are

53 147 FERC ¶ 61,060 (2014).
54 151 FERC ¶ 61,208 (2015).

55 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.
56 See "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, § 4.2.4 Planned Generation Capacity Resources – External, § 4.6.4 Importing an External Generation Resource, Rev. 41 (Jan. 1, 2019).
57 OATT Schedule 1 § 1.10.1A.

evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits. If the offer is not accepted in the Day-Ahead Energy Market, but the unit is requested during the operating day, the PJM dispatch operator will notify the participant. The market participant will then submit a tag to match the request. This tag will also be subject to all scheduling timing requirements and PJM interchange ramp limits.

Planned External Generation Capacity Resource

Planned external generation capacity resources are eligible to be offered into an RPM auction if they meet specific requirements.[58] [59] Planned external generation capacity resources are proposed generation capacity resources, or a proposed increase in the capability of an existing generation capacity resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[60] An external generation capacity resource becomes an existing generation capacity resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM auction.[61]

Exporting Capacity

Nonfirm transmission can be used to export capacity from the PJM region. A generation capacity resource located in the PJM region not committed to service of PJM loads may be removed from PJM capacity resource status if the Capacity Market Seller shows that the resource has a financially and physically firm commitment to an external sale of its capacity.[62] The Capacity Market Seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[63]

The MMU evaluates requests submitted by Capacity Market Sellers to export generation capacity resources, makes a determination as to whether the resource meets the applicable criteria to export, and must inform both the Capacity Market Seller and PJM of such determination.[64]

When submitting a real-time market export capacity transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Capacity transactions must designate the transaction as capacity when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits.

Table 5-10 RPM imports: 2007/2008 through 2021/2022 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8

58 See RAA § 1.69A.

59 See "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 41 (Jan. 1, 2019).

60 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).

61 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

62 OATT Attachment DD § 6.6(g).

63 *Id.*

64 OATT Attachment M-Appendix § II.C.2.

Demand Resources

There are three basic demand products incorporated in the RPM market design:[65]

- **Demand Resources (DR).** Interruptible load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Interruptible Load for Reliability (ILR).** Interruptible load resource that is not offered into the RPM auction, but receives the final zonal ILR price determined after the second incremental auction. The ILR product was eliminated after the 2011/2012 Delivery Year.
- **Energy Efficiency (EE) Resources.** Load resources that are offered into an RPM auction as capacity and receive the relevant LDA or RTO resource clearing price. The EE resource type was eligible to be offered in RPM auctions starting with the 2012/2013 Delivery Year and in incremental auctions in the 2011/2012 Delivery Year.[66]

Effective for the 2014/2015 through the 2017/2018 Delivery Year, there are three types of Demand Resource products included in the RPM market design:[67 68]

- **Annual DR.** A demand resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
- **Extended Summer DR.** A demand resource that is required to be available on any day from June through October and the following May in the relevant delivery year for an unlimited number of interruptions. Extended summer DR is required to be capable of maintaining each interruption for only 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
- **Limited DR.** A demand resource that is required to be available on weekdays not including NERC holidays during the period of June through September in the relevant delivery year for up to 10 interruptions. Limited DR is required to be capable of maintaining each interruption for only six hours only during the hours of 12:00 p.m. to 8:00 p.m. EPT.

Effective for the 2018/2019 and the 2019/2020 Delivery Years, there are two types of demand resource and energy efficiency resource products included in the RPM market design:[69 70]

- **Base Capacity Resources**
  - **Base Capacity Demand Resources.** A demand resource that is required to be available on any day from June through September for an unlimited number of interruptions. Base capacity DR is required to be capable of maintaining each interruption for at least 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Base Capacity Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast for the delivery year for which the base capacity energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the base capacity energy efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.
- **Capacity Performance Resources**
  - **Annual Demand Resources.** A demand resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only 10 hours during the hours of 10:00 a.m. to 10:00

65 Effective June 1, 2007, the PJM active load management (ALM) program was replaced by the PJM load management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered into RPM auctions as capacity resources and receive the clearing price.
66 Letter Order in Docket No. ER10-366-000 (January 22, 2010).
67 134 FERC ¶ 61,066 (2011).
68 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Article 1.
69 151 FERC ¶ 61,208.
70 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.

— **Annual Energy Efficiency Resources.** A project designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the annual energy efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, and the period from the hour ending 8:00 EPT and the hour ending 9:00 EPT and the period from the hour ending 19:00 EPT and the hour ending 20:00 EPT from January through February, excluding weekends and federal holidays.

Effective with the 2020/2021 Delivery Year, the Capacity Performance Product will be the only capacity product type, with two possible season types, annual and summer.

- **Annual Capacity Performance Resources**
  - Annual Demand Resources
  - Annual Energy Efficiency Resources
- **Seasonal Capacity Performance Resources**
  - **Summer-Period Demand Resources.** A demand resource that is required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions. Summer period DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Summer-Period Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the summer-period efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.

As shown in Table 5-11, Table 5-12, and Table 5-13, capacity in the RPM load management programs was 10,798.7 MW for June 1, 2018, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2018/2019 Delivery Year (13,731.7 MW) less replacement capacity (2,933.0 MW).

Table 5-11 RPM load management statistics by LDA: June 1, 2017 to June 1, 2021[71 72 73 74]

		UCAP (MW)														
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
01-Jun-17	DR cleared	11,870.7	4,584.5	1,630.9	1,464.1	86.3	402.8	157.1	658.3	1,256.0	323.5	1,602.9	805.8	811.9		
	EE cleared	1,922.3	547.7	180.0	291.5	5.6	55.2	18.5	155.4	192.3	41.4	747.6	136.1	43.2		
	DR net replacements	(3,870.8)	(1,461.6)	(555.7)	(344.8)	(39.5)	(107.9)	(30.6)	(136.5)	(457.2)	(163.1)	(279.2)	(208.3)	(299.2)		
	EE net replacements	195.6	145.8	20.6	98.3	(0.4)	4.4	2.6	26.2	(41.9)	(11.7)	10.3	72.1	(9.9)		
	Total RPM load management	10,117.8	3,816.4	1,275.8	1,509.1	52.0	354.5	147.6	703.4	949.2	190.1	2,081.6	805.7	546.0		
01-Jun-18	DR cleared	11,435.4	4,361.9	1,707.2	1,226.4	86.8	389.9	139.2	559.3	1,034.3	287.2	1,895.2	667.1	716.2		
	EE cleared	2,296.3	706.8	315.9	317.6	9.2	102.0	45.2	186.1	184.4	33.2	807.4	131.5	43.1		
	DR net replacements	(3,181.8)	(1,268.4)	(584.3)	(199.5)	(52.4)	(150.9)	(43.6)	(25.6)	(261.0)	(136.7)	(430.0)	(173.9)	(220.0)		
	EE net replacements	248.8	163.0	45.5	107.6	1.1	22.4	9.1	(8.9)	14.7	4.7	29.0	116.5	5.4		
	Total RPM load management	10,798.7	3,963.3	1,484.3	1,452.1	44.7	363.4	149.9	710.9	972.4	188.4	2,301.6	741.2	544.7		
01-Jun-19	DR cleared	10,422.7	3,810.5	1,650.7	758.9	91.3	381.1	176.5	496.5	906.3	289.9	1,757.4	262.4	739.8		
	EE cleared	2,198.2	675.8	297.2	272.5	5.4	94.1	33.3	151.3	188.1	39.6	750.1	121.2	62.9		
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
	Total RPM load management	12,620.9	4,486.3	1,947.9	1,031.4	96.7	475.2	209.8	647.8	1,094.4	329.5	2,507.5	383.6	802.7		
01-Jun-20	DR cleared	9,008.7	2,823.2	1,168.9	481.1	72.6	339.0	152.7	234.6	853.0	227.1	1,623.0	246.5	615.6	211.4	164.1
	EE cleared	2,080.5	683.7	346.7	261.4	8.7	119.6	38.7	114.2	172.0	40.1	722.6	147.2	44.2	53.8	74.1
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total RPM load management	11,089.2	3,506.9	1,515.6	742.5	81.3	458.6	191.4	348.8	1,025.0	267.2	2,345.6	393.7	659.8	265.2	238.2
01-Jun-21	DR cleared	11,125.8	3,413.4	1,378.9	624.9	66.3	407.9	188.6	345.9	1,142.4	272.8	1,997.8	279.0	684.7	227.7	213.8
	EE cleared	2,832.0	938.7	617.0	207.0	13.6	240.1	72.9	102.6	148.2	36.2	770.5	104.4	72.4	60.1	89.7
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total RPM load management	13,957.8	4,352.1	1,995.9	831.9	79.9	648.0	261.5	448.5	1,290.6	309.0	2,768.3	383.4	757.1	287.8	303.5

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2021[75 76 77]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,181.8)	8,253.6		8,252.6	8,512.0	1.091	9,282.4
01-Jun-19	10,422.7	0.0	0.0	10,422.7	0.0	10,422.7	0.0	1.090	0.0
01-Jun-20	9,008.7	0.0	0.0	9,008.7	0.0	9,008.7	0.0	1.090	0.0
01-Jun-21	11,125.8	0.0	0.0	11,125.8	0.0	11,125.8	0.0	1.090	0.0

71 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.

72 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year include transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

73 See OATT Attachment DD § 5.14C. The reported DR cleared MW for the 2015/2016 and 2016/2017 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

74 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

75 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.

76 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

77 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2021[78]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-08	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-09	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-10	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-11	76.4	0.0	0.2	76.6	0.0	76.6
01-Jun-12	666.1	0.0	(34.9)	631.2	(5.1)	626.1
01-Jun-13	904.2	0.0	120.6	1,024.8	(13.5)	1,011.3
01-Jun-14	1,077.7	0.0	204.7	1,282.4	(0.2)	1,282.2
01-Jun-15	1,189.6	0.0	335.9	1,525.5	(0.9)	1,524.6
01-Jun-16	1,723.2	0.0	61.1	1,784.3	(0.5)	1,783.8
01-Jun-17	1,922.3	0.0	195.6	2,117.9	(7.4)	2,110.5
01-Jun-18	2,296.3	0.0	248.8	2,545.1	0.0	2,545.1
01-Jun-19	2,198.2	0.0	0.0	2,198.2	0.0	2,198.2
01-Jun-20	2,080.5	0.0	0.0	2,080.5	0.0	2,080.5
01-Jun-21	2,832.0	0.0	0.0	2,832.0	0.0	2,832.0

Market Conduct

Offer Caps and Offer Floors

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the Capacity Market Seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[79] [80] [81] For Base Capacity, offer caps are defined in the PJM Tariff as avoidable costs less PJM market revenues, or opportunity costs based on the potential sale of capacity in an external market. For Capacity Performance Resources, offer caps are defined in the PJM Tariff as the applicable zonal net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market. For RPM Third Incremental Auctions, capacity market sellers may elect, for Base Capacity offers, an offer cap equal to 1.1 times the BRA clearing price for the relevant LDA and delivery year or, for Capacity Performance offers, an offer cap equal to the greater of the net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year.

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[82] In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a generation capacity resource, termed Avoidable Project Investment Recovery (APIR). Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. For Capacity Performance Resources, avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts and expected bonus performance payments/non-performance charges.[83] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for delivery years prior to 2020/2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[84]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk

78 Pursuant to PJM Operating Agreement § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

79 See OATT Attachment DD § 6.5.

80 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).

81 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

82 OATT Attachment DD § 6.8 (b).

83 For details on the competitive offer of a capacity performance resource, see "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

84 OATT Attachment DD § 6.8 (a).

(CPQR).[85] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows Capacity Market Sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Calculation of Offer Caps

The competitive offer of a Capacity Performance resource is based on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (Net ACR); and the resource's performance during performance assessment intervals (A) in the delivery year.[86]

The competitive offer of a Capacity Performance resource is also based on a market seller's expectations of system level variables: the number of performance assessment intervals (PAI) in a delivery year (H) where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment hours, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The level of bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment hours for reasons defined in the PJM OATT.[87]

85 151 FERC ¶ 61,208.

86 The model is only applicable to generation resources and storage resources that have an annual obligation to perform with very limited specific excuses as defined in the PJM OATT.

87 OATT Attachment DD § 10A (d).

The default offer cap defined in the PJM tariff, Net CONE times the average Balancing Ratio, is based on a number of assumptions:

1. The Net ACR of a resource is less than its expected energy only bonuses:

$$ACR \leq \sum_{i=1}^{H}(CPBR_i \times A_i)$$

$$or\ ACR \leq \left(\frac{1}{12}\right)(CPBR \times H \times \bar{A})$$

2. The expected number of performance assessment intervals equals 360. (H = 360 intervals, or 12 hours)
3. The expected value of the bonus performance payment rate (CPBR) is equal to the nonperformance charge rate (PPR)
4. The average expected performance of the resource during performance assessment hours ($\bar{A}$)

The competitive offer of such a resource is:

$$p = \left(\frac{1}{12}\right)(CPBR \times H \times \bar{A} + PPR \times H \times (\bar{B} - \bar{A}))$$

In other words, the competitive offer of such a resource is the opportunity cost of taking on the capacity obligation which equals the sum of the energy only bonuses it would have earned $(CPBR \times H \times \bar{A})/12$ and the net nonperformance charges it would incur by taking on the capacity obligation $(PPR \times H \times (\bar{B} - \bar{A})/12)$. Both the components are proportional to the expected number of performance assessment intervals. If the expected number of performance assessment intervals (H) is significantly lower than the value used to determine the non-performance charge rate (PPR), the opportunity of earning bonuses as an energy only resource, as well as the net non-performance charges incurred by taking on a capacity obligation are lower. Under such a scenario, the likelihood that that the resource's Net ACR is lower than the expected energy only bonuses is reduced. For resources whose Net ACR is greater than the expected energy only bonuses, the competitive offer is the Net ACR adjusted with any capacity performance bonuses or non-performance charges they expect to incur during the delivery year.

This means that when the expected number of performance assessment intervals are lower than the value used to determine the non-performance charge rate (360 intervals, or 30 hours), the current default offer cap of Net CONE times B overstates the competitive offer and the market seller offer cap.

The recent history of a low number of emergency actions in PJM reflect the improvements to generator performance with the capacity performance design, the reduction in actual and expected pool wide outage rates as a result of new units added to the system and the retirement of old units, the upward biased peak load forecasts used in RPM, and the high reserve margins in capacity.[88] [89] Given these developments, the assumption that there would be 30 hours of emergency actions in a year that would trigger performance assessment intervals is unsupported. Since the non-performance charge rate is defined in the tariff as net CONE divided by 30 hours, the adjusted default offer cap to reflect a lower estimate for the number of PAIs is much lower than net CONE times B.

In the 2021/2022 RPM Base Residual Auction, net CONE times B exceeded the actual competitive offer level of a Low ACR resource that the default offer cap is based on.[90] While most participants offered in the 2021/2022 RPM Base Residual Auction at competitive levels based on their expectation of the number of performance assessment hours and projected net revenues, some market participants did not offer competitively and affected the market clearing prices.

MOPR

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[91] The changes to the MOPR included updating the calculation of the net Cost of New Entry (CONE) for Combined Cycle (CC) and Combustion Turbine (CT) plants which is used as a benchmark value in assessing the competitiveness of a sell offer, increasing the percentage value used in the screen to 90 percent for CC and CT plants, eliminating the net-short requirement as a prerequisite for applying the MOPR, eliminating the impact screen, revising the process for reviewing proposed exceptions to the defined minimum sell offer price, and clarifying which resources are subject to the MOPR along with the duration of mitigation. Subsequent FERC Orders revised the MOPR, including clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process.[92]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[93] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exception process for those that do not qualify for the Competitive Entry or Self Supply Exemptions; changing the applicability of MOPR to include only combustion turbine, combined cycle, integrated gasification combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the transmission system; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen from 90 percent to 100 percent of the applicable net CONE values; and broadening the region subject to MOPR to the entire RTO from modeled LDAs only.

Effective December 8, 2017, FERC issued an order on remand rejecting PJM's MOPR proposal in Docket No. ER13-535, and as a result, the rules that were in effect prior to PJM's December 7, 2012, MOPR filing were reinstated. These changes include eliminating the Competitive Entry and Self Supply Exemptions and retaining only the Unit Specific Exception request; narrowing the region subject to MOPR from the entire RTO to only modeled LDAs; eliminating the 20.0 MW threshold for applicability; redefining the applicability criteria to exclude nuclear, coal, IGCC, hydroelectric, wind and solar facilities; modifying the duration of mitigation criteria from clearing in a prior delivery year to clearing in any delivery year; and changing the procedural deadlines.[94]

88 PJM experienced zero emergency events since April 2014, that would have triggered a PAI in an area that at least encompasses a PJM transmission zone. See "Balancing Ratio Determination Issue", at 12 <http://www.pjm.com/-/media/committees-groups/ committees/mic/20180404/20180404-item-10b1-balancing-ratio-determination-solution-options.ashx> (April 4, 2018).

89 See Table 5-7.

90 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," at Attachment B <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

91 135 FERC ¶ 61,022 (2011).

92 135 FERC ¶ 61,022 (2011), *order on reh'g*, 137 FERC ¶ 61,145 (2011).

93 143 FERC ¶ 61,090 (2013).

94 161 FERC ¶ 61,252 (2017).

2018/2019 RPM Base Residual Auction

As shown in Table 5-14, 473 generation resources submitted Base Capacity offers in the 2018/2019 RPM Base Residual Auction. The MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 were based on the technology specific default (proxy) ACR values, 53 were unit-specific offer caps (11.2 percent of all generation resources), of which 45 included an APIR component, eight Planned Generation Capacity Resources had uncapped offers (1.7 percent), and the remaining 246 generation resources were price takers (52.0 percent). Market power mitigation was applied to the Base Capacity sell offers of 18 generation capacity resources, including 3,271.9 MW.

As shown in Table 5-14, 992 generation resources submitted Capacity Performance offers in the 2018/2019 RPM Base Residual Auction. The MMU calculated offer caps for 35 generation resources (3.5 percent), all of which were unit-specific with an APIR component, 15 Planned Generation Capacity Resources had uncapped offers (1.5 percent), and the remaining 54 generation resources were price takers (5.4 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

Of the 473 generation resources which submitted Base Capacity offers, 45 (9.5 percent) included an APIR component. Of the 992 generation resources which submitted Capacity Performance offers, 35 (3.5 percent) included an APIR component. As shown in Table 5-18, the weighted average gross ACR for units with APIR was $406.58 per MW-day for Base Capacity Resources and $496.37 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $321.80 per MW-day for Base Capacity Resources and $356.54 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of $281.13 per MW-day for Base Capacity Resources and $344.93 for Capacity Performance Resources. The maximum APIR effect ($1,051.98 per MW-day for Base Capacity Resources and Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of $0.00 per MW-day for Base Capacity Resources and $10.08 per MW-day for Capacity Performance Resources.

2018/2019 RPM First Incremental Auction

As shown in Table 5-14, 80 generation resources submitted Base Capacity offers in the 2018/2019 RPM First Incremental Auction. The MMU calculated offer caps for 30 generation resources (37.5 percent), of which 18 were based on the technology specific default (proxy) ACR values and 12 were unit-specific offer caps (15.0 percent of all generation resources), of which all of which included an APIR component. Of the 30 generation resources with Base Capacity offers, four Planned Generation Capacity Resources had uncapped offers (5.0 percent), and the remaining 46 generation resources were price takers (57.5 percent). Market power mitigation was applied to the Base Capacity sell offers of three generation resources, including 8.2 MW.

As shown in Table 5-14, 293 generation resources submitted Capacity Performance offers in the 2018/2019 RPM First Incremental Auction. The MMU calculated offer caps for nine generation resources (3.1 percent), all of which were unit-specific with an APIR component. Of the 293 generation resources, 261 generation resources had the net CONE times B offer cap (89.1 percent), seven Planned Generation Capacity Resources had uncapped offers (2.4 percent), one generation resource had an uncapped planned uprate plus net CONE times B offer cap for the existing portion of the unit (0.3 percent), and the remaining 15 generation resources were price takers (5.1 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2018/2019 RPM Second Incremental Auction

As shown in Table 5-14, 68 generation resources submitted Base Capacity offers in the 2018/2019 RPM Second Incremental Auction. The MMU calculated offer caps for 23 generation resources (33.8 percent), of which 12 were based on the technology specific default (proxy) ACR values and 11 were unit-specific offer caps (16.2 percent of all generation resources), of which all included an APIR component. Of the 68 generation resources with Base Capacity offers, six Planned Generation Capacity Resources had uncapped offers (8.8 percent), and the remaining 39 generation resources were price takers (57.4 percent). Market power mitigation was applied to the Base Capacity sell offers of zero generation resources, including 0.0 MW.

As shown in Table 5-14, 344 generation resources submitted Capacity Performance offers in the 2018/2019 RPM Second Incremental Auction. The MMU calculated offer caps for five generation resources (1.5 percent), all of which were unit-specific with an APIR component. Of the 344 generation resources, 327 generation resources had the net CONE times B offer cap (95.1 percent), four Planned Generation Capacity Resources had uncapped offers (1.2 percent), and the remaining eight generation resources were price takers (2.3 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2018/2019 RPM Third Incremental Auction

As shown in Table 5-14, 211 generation resources submitted Base Capacity offers in the 2018/2019 RPM Third Incremental Auction. The MMU calculated offer caps for five generation resources (2.4 percent), of which one was based on the technology specific default (proxy) ACR values and four were unit-specific offer caps (1.9 percent of all generation resources), of which all included an APIR component. Of the 211 generation resources with Base Capacity offers, 137 generation resources elected the offer cap option of 1.1 times the BRA clearing price (64.9 percent), five Planned Generation Capacity Resources had uncapped offers (2.4 percent), and the remaining 64 generation resources were price takers (30.3 percent). Market power mitigation was applied to the Base Capacity sell offers of zero generation resources, including 0.0 MW.

As shown in Table 5-14, 495 generation resources submitted Capacity Performance offers in the 2018/2019 RPM Third Incremental Auction. The MMU calculated offer caps for three generation resources (06 percent), all of which were unit-specific with an APIR component. Of the 495 generation resources, 364 generation resources had the net CONE times B offer cap (73.5 percent), 98 generation resources elected the offer cap option of 1.1 times the BRA clearing price (19.8 percent), two Planned Generation Capacity Resources had uncapped offers (0.4 percent), and the remaining 28 generation resources were price takers (5.7 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2019/2020 RPM Base Residual Auction

As shown in Table 5-15, 505 generation resources submitted Base Capacity offers in the 2019/2020 RPM Base Residual Auction. The MMU calculated offer caps for 212 generation resources (42.0 percent), of which 171 were based on the technology specific default (proxy) ACR values and 41 were unit-specific offer caps (8.1 percent of all generation resources), of which 34 included an APIR component. Of the 505 generation resources, nine Planned Generation Capacity Resources had uncapped offers (1.8 percent), and the remaining 284 generation resources were price takers (56.2 percent). Market power mitigation was applied to the Base Capacity sell offers of 34 generation resources, including 3,116.5 MW.

As shown in Table 5-15, 1,003 generation resources submitted Capacity Performance offers in the 2019/2020 RPM Base Residual Auction. The MMU calculated offer caps for 25 generation resources (2.5 percent), all of which were unit-specific with an APIR component. Of the 1,003 generation resources, 888 generation resources had the net CONE times B offer cap (88.5 percent), 14 Planned Generation Capacity Resources had uncapped offers (1.4 percent), two generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units (0.2 percent), and the remaining 74 generation resources were price takers (5.4 percent). Market power mitigation was applied to the Capacity Performance sell offers of three generation resources, including 50.8 MW.

Of the 505 generation resources which submitted Base Capacity offers, 34 (6.7 percent) included an APIR component. Of the 1,003 generation resources which submitted Capacity Performance offers, 25 (2.5 percent) included an APIR component. As shown in Table 5-19, the weighted average gross ACR for units with APIR was $341.40 per MW-day for Base Capacity Resources and $499.18 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $271.22 per MW-day for Base Capacity Resources and $323.27 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of $230.67 per MW-day for Base Capacity Resources and $375.38 for Capacity Performance Resources. The maximum APIR effect ($1,104.93 per MW-day for

Base Capacity Resources and Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of $0.00 per MW-day for Base Capacity Resources and $1.53 per MW-day for Capacity Performance Resources.

2019/2020 RPM First Incremental Auction

As shown in Table 5-15, 81 generation resources submitted Base Capacity offers in the 2019/2020 RPM First Incremental Auction. The MMU calculated offer caps for 28 generation resources (34.6 percent), of which 17 were based on the technology specific default (proxy) ACR values and 11 were unit-specific offer caps (13.6 percent of all generation resources), of which all included an APIR component. Of the 81 generation resources with Base Capacity offers, the remaining 53 generation resources were price takers (65.4 percent). Market power mitigation was applied to the Base Capacity sell offers of zero generation resources, including 0.0 MW.

As shown in Table 5-15, 382 generation resources submitted Capacity Performance offers in the 2019/2020 RPM First Incremental Auction. The MMU calculated offer caps for seven generation resources (1.8 percent), of which six were unit-specific with an APIR component and one was based on the technology specific default (proxy) ACR value. Of the 382 generation resources, 362 generation resources had the net CONE times B offer cap (94.8 percent), one Planned Generation Capacity Resource had an uncapped offer (0.3 percent), one generation resource had an uncapped planned uprate plus price taker status for the existing portion of the unit (0.3 percent), and the remaining 11 generation resources were price takers (2.9 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2019/2020 RPM Second Incremental Auction

As shown in Table 5-15, 72 generation resources submitted Base Capacity offers in the 2019/2020 RPM Second Incremental Auction. The MMU calculated offer caps for 18 generation resources (25.0 percent), of which 10 were based on the technology specific default (proxy) ACR values and 8 were unit-specific offer caps (11.1 percent of all generation resources), of which all included an APIR component. Of the 72 generation resources with Base Capacity offers, two Planned Generation Capacity Resources had uncapped offers (2.8 percent), one generation resource had an uncapped planned uprate price taker for the existing portion of the unit, and the remaining 51 generation resources were price takers (70.8 percent). Market power mitigation was applied to the Base Capacity sell offers of one generation resource, including 0.1 MW.

As shown in Table 5-15, 409 generation resources submitted Capacity Performance offers in the 2019/2020 RPM Second Incremental Auction. The MMU calculated offer caps for six generation resources (1.5 percent), all of which were unit-specific including one generation resource (0.2 percent) with an Avoidable Project Investment Recovery Rate (APIR) and a CPQR component and five generation resources (1.2 percent) with an APIR component and no CPQR component. Of the 409 generation resources, 350 generation resources had the net CONE times B offer cap (85.6 percent), three generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units, one generation resource had uncapped planned uprates and price taker for the existing portion of the unit, and the remaining 49 generation resources were price takers (12.0 percent). Market power mitigation was applied to the Capacity Performance sell offers of one generation resource, including 0.2 MW.

2020/2021 RPM Base Residual Auction

As shown in Table 5-16, 1,114 generation resources submitted Capacity Performance offers in the 2020/2021 RPM Base Residual Auction. The MMU calculated offer caps for 14 generation resources that submitted Capacity Performance offers. Unit-specific ACR-based offer caps were calculated for 14 generation resources (1.3 percent) including 11 generation resources (1.0 percent) with an Avoidable Project Investment Recovery Rate (APIR) and a CPQR component and three generation resources (0.3 percent) with an APIR component and no CPQR component. Of the 1,114 generation resources offered as Capacity Performance, 956 generation resources had the net CONE times B offer cap, zero generation resources had opportunity cost-based offer caps, 12 Planned Generation Capacity Resources had uncapped offers, 18 generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units, two generation resource had an uncapped planned uprate plus price taker status for the existing portion of the unit, while the remaining 112 generation resources were price takers. Market power mitigation was applied to the sell offers of zero generation resources, including 0.0 MW.

Of the 1,114 generation resources which submitted Capacity Performance offers, 14 (1.3 percent) included an APIR component. As shown in Table 5-20, the weighted average gross ACR for units with APIR was $498.15 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $209.18 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of $235.67 per MW-day for Capacity Performance Resources. The maximum APIR effect ($464.71 per MW-day for Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of $0.23 per MW-day for Capacity Performance Resources.

2020/2021 RPM First Incremental Auction

As shown in Table 5-16, 397 generation resources submitted Capacity Performance offers in the 2020/2021 RPM First Incremental Auction. The MMU calculated offer caps for eight generation resources that submitted Capacity Performance offers. Unit-specific ACR-based offer caps were calculated for eight generation resources (2.0 percent) including seven generation resources (1.8 percent) with an Avoidable Project Investment Recovery Rate (APIR) and a CPQR component and one generation resources (0.3 percent) with an APIR component and no CPQR component. Of the 397 generation resources offered as Capacity Performance, 371 generation resources had the net CONE times B offer cap, zero generation resources had opportunity cost-based offer caps, six Planned Generation Capacity Resources had uncapped offers, two generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units, while the remaining 10 generation resources were price takers. Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2021/2022 RPM Base Residual Auction

As shown in Table 5-17, 1,132 generation resources submitted Capacity Performance offers in the 2021/2022 RPM Base Residual Auction. The MMU calculated offer caps for eight generation resources that submitted Capacity Performance offers. Unit-specific ACR-based offer caps were calculated for eight generation resources (0.7 percent) including five generation resources (0.4 percent) with an Avoidable Project Investment Recovery Rate (APIR) and a CPQR component and three generation resources (0.3 percent) with an APIR component and no CPQR component. Of the 1,132 generation resources offered as Capacity Performance, 953 generation resources had the net CONE times B offer cap, zero generation resources had opportunity cost-based offer caps, 11 Planned Generation Capacity Resources had uncapped offers, 31 generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units, while the remaining 129 generation resources were price takers. Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

MOPR Statistics

Market power mitigation measures are applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception. As shown in Table 5-21, of the 7,276.0 ICAP MW of MOPR Unit-Specific Exception requests for the 2021/2022 RPM Base Residual Auction, requests for 4,344.0 MW were granted.

Table 5-14 ACR statistics: 2018/2019 RPM Auctions

	2018/2019 Base Residual Auction				2018/2019 First Incremental Auction			
	Base Capacity		Capacity Performance		Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	164	34.7%	0	0.0%	18	22.5%	0	0.0%
Unit specific ACR (APIR)	45	9.5%	9	0.9%	12	15.0%	8	2.7%
Unit specific ACR (APIR and CPQR)	0	0	26	2.6%	0	0	1	0.3%
Unit specific ACR (non-APIR)	1	0.2%	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%	0	0	0	0.0%
Opportunity cost input	7	1.5%	0	0.0%	0	0.0%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Net CONE times B	NA	NA	881	88.8%	NA	NA	261	89.1%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and default ACR	2	0.4%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	6	0.6%	NA	NA	1	0.3%
Uncapped planned uprate and price taker	0	0.0%	1	0.1%	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned generation resources	8	1.7%	15	1.5%	4	5.0%	7	2.4%
Existing generation resources as price takers	246	52.0%	54	5.4%	46	57.5%	15	5.1%
Total Generation Capacity Resources offered	473	100.0%	992	100.0%	80	100.0%	293	100.0%

	2018/2019 Second Incremental Auction				2018/2019 Third Incremental Auction			
	Base Capacity		Capacity Performance		Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	12	17.6%	0	0.0%	1	0.5%	0	0.0%
Unit specific ACR (APIR)	11	16.2%	5	1.5%	4	1.9%	3	0.6%
Unit specific ACR (APIR and CPQR)	0	0	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%	0	0.0%	0	0.0%
Opportunity cost input	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Net CONE times B	NA	NA	327	95.1%	NA	NA	364	73.5%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	137	64.9%	98	19.8%
Uncapped planned uprate and default ACR	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	0	0.0%	NA	NA	0	0.0%
Uncapped planned uprate and price taker	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	0	0.0%	0	0.0%
Uncapped planned generation resources	6	8.8%	4	1.2%	5	2.4%	2	0.4%
Existing generation resources as price takers	39	57.4%	8	2.3%	64	30.3%	28	5.7%
Total Generation Capacity Resources offered	68	100.0%	344	100.0%	211	100.0%	495	100.0%

Table 5-15 ACR Statistics: 2019/2020 RPM Auctions

	2019/2020 Base Residual Auction				2019/2020 First Incremental Auction			
	Base Capacity		Capacity Performance		Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	171	33.9%	0	0.0%	17	21.0%	1	0.3%
Unit specific ACR (APIR)	34	6.7%	8	0.8%	11	13.6%	5	1.3%
Unit specific ACR (APIR and CPQR)	0	0	17	1.7%	0	0	1	0.3%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%	0	0	0	0.0%
Opportunity cost input	7	1.4%	0	0.0%	0	0.0%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Net CONE times B	NA	NA	888	88.5%	NA	NA	362	94.8%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and default ACR	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	2	0.2%	NA	NA	0	0.0%
Uncapped planned uprate and price taker	0	0.0%	0	0.0%	0	0.0%	1	0.3%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned generation resources	9	1.8%	14	1.4%	0	0.0%	1	0.3%
Existing generation resources as price takers	284	56.2%	74	7.4%	53	65.4%	11	2.9%
Total Generation Capacity Resources offered	505	100.0%	1,003	100.0%	81	100.0%	382	100.0%

	2019/2020 Second Incremental Auction			
	Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	10	13.9%	NA	NA
Unit specific ACR (APIR)	8	11.1%	5	1.2%
Unit specific ACR (APIR and CPQR)	0	0	1	0.2%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%
Opportunity cost input	0	0.0%	0	0.0%
Default ACR and opportunity cost	0	0.0%	NA	NA
Net CONE times B	NA	NA	350	85.6%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	0	0.0%	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	3	0.7%
Uncapped planned uprate and price taker	1	1.4%	1	0.2%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	2	2.8%	0	0.0%
Existing generation resources as price takers	51	70.8%	49	12.0%
Total Generation Capacity Resources offered	72	100.0%	409	100.0%

Table 5-16 ACR Statistics: 2020/2021 RPM Auctions

	2020/2021 Base Residual Auction		2020/2021 First Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	NA	NA	NA	NA
Unit specific ACR (APIR)	3	0.3%	1	0.3%
Unit specific ACR (APIR and CPQR)	11	1.0%	7	1.8%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%	0	0.0%
Opportunity cost input	0	0.0%	0	0.0%
Default ACR and opportunity cost	NA	NA	NA	NA
Net CONE times B	956	85.8%	371	93.5%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	NA	NA	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	18	1.6%	2	0.5%
Uncapped planned uprate and price taker	2	0.2%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	12	1.1%	6	1.5%
Existing generation resources as price takers	112	10.1%	10	2.5%
Total Generation Capacity Resources offered	1,114	100.0%	397	100.0%

Table 5-17 ACR Statistics: 2021/2022 RPM Auction

	2021/2022 Base Residual Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	NA	NA
Unit specific ACR (APIR)	3	0.3%
Unit specific ACR (APIR and CPQR)	5	0.4%
Unit specific ACR (non-APIR)	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%
Opportunity cost input	0	0.0%
Default ACR and opportunity cost	NA	NA
Net CONE times B	953	84.2%
Offer cap of 1.1 times BRA clearing price elected	NA	NA
Uncapped planned uprate and default ACR	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%
Uncapped planned uprate and Net CONE times B	31	2.7%
Uncapped planned uprate and price taker	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA
Uncapped planned generation resources	11	1.0%
Existing generation resources as price takers	129	11.4%
Total Generation Capacity Resources offered	1,132	100.0%

Table 5-18 APIR Statistics: 2018/2019 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)	
	Base Capacity	Capacity Performance
Non-APIR units		
ACR	$85.36	$197.45
Net revenues	$117.38	$131.61
Offer caps	$30.74	$65.83
APIR units		
ACR	$406.58	$496.37
Net revenues	$83.43	$139.25
Offer caps	$321.80	$356.54
APIR	$281.13	$344.93
CPQR	$0.00	$10.08
Maximum APIR effect	$1,051.98	$1,051.98

Table 5-19 APIR Statistics: 2019/2020 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)	
	Base Capacity	Capacity Performance
Non-APIR units		
ACR	$89.05	
Net revenues	$150.86	
Offer caps	$33.97	
APIR units		
ACR	$341.40	$499.18
Net revenues	$65.48	$167.61
Offer caps	$271.22	$323.27
APIR	$230.67	$375.38
CPQR	$0.00	$1.53
Maximum APIR effect	$1,104.93	$1,104.93

Table 5-20 APIR Statistics: 2020/2021 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)
Non-APIR units	
ACR	
Net revenues	
Offer caps	
APIR units	
ACR	$498.15
Net revenues	$277.52
Offer caps	$209.18
APIR	$235.67
CPQR	$0.23
Maximum APIR effect	$464.71

Table 5-21 MOPR statistics: 2018/2019 through 2021/2022 RPM Base Residual Auctions[95]

		Number of Requests	ICAP (MW)			UCAP (MW)	
		(Company-Plant Level)	Requested	Granted	Offered	Offered	Cleared
2018/2019 Base Residual Auction	Competitive Entry Exemption	28	13,462.5	13,462.5	3,723.3	3,563.6	3,563.6
	Self-Supply Exemption	0	0.0	0.0	0.0	0.0	0.0
	Unit-Specific Exception for resources	0	0.0	0.0	0.0	0.0	0.0
	Unit-Specific Exception for uprates	0	0.0	0.0	0.0	0.0	0.0
	Other MOPR Screened Generation Resources	0	0.0	0.0	543.1	511.5	0.0
	Total	28	13,462.5	13,462.5	4,266.4	4,075.1	3,563.6
2019/2020 Base Residual Auction	Competitive Entry Exemption	28	12,270.0	12,270.0	4,671.0	4,515.1	3,561.7
	Self-Supply Exemption	3	1,827.2	1,827.2	1,779.5	1,697.8	1,697.8
	Unit-Specific Exception for resources	0	0.0	0.0	0.0	0.0	0.0
	Unit-Specific Exception for uprates	0	0.0	0.0	0.0	0.0	0.0
	Other MOPR Screened Generation Resources	0	0.0	0.0	14.4	14.4	0.0
	Total	31	14,097.2	14,097.2	6,464.9	6,227.3	5,259.5
2020/2021 Base Residual Auction	Competitive Entry Exemption	27	12,171.0	12,171.0	3,212.5	3,161.1	2,646.7
	Self-Supply Exemption	0	0.0	0.0	0.0	0.0	0.0
	Unit-Specific Exception for resources	0	0.0	0.0	0.0	0.0	0.0
	Unit-Specific Exception for uprates	0	0.0	0.0	0.0	0.0	0.0
	Other MOPR Screened Generation Resources	0	0.0	0.0	142.0	140.1	0.0
	Total	27	12,171.0	12,171.0	3,354.5	3,301.2	2,646.7
2021/2022 Base Residual Auction	Unit-Specific Exception for resources	8	6,605.0	3,673.0	0.0	0.0	0.0
	Unit-Specific Exception for uprates	15	671.0	671.0	131.3	127.6	127.6
	Other MOPR Screened Generation Resources	0	0.0	0.0	177.5	174.2	0.0
	Total	23	7,276.0	4,344.0	308.8	301.8	127.6

95 There were additional MOPR Screened Generation Resources for which no exceptions or exemptions were requested and to which the MOPR floor was applied. Some numbers not reported as a result of PJM confidentiality rules.

Replacement Capacity[96]

Table 5-22 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2021. The 2019 through 2021 numbers are not final.

Table 5-22 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2021

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	171,237.2	0.0	(1,083.5)	170,153.7	0.0	170,153.7
01-Jun-20	168,634.0	0.0	(610.1)	168,023.9	0.0	168,023.9
01-Jun-21	163,627.3	0.0	0.0	163,627.3	0.0	163,627.3

Market Performance

Figure 5-7 shows cleared MW weighted average capacity market prices on a Delivery Year basis for the entire history of the PJM capacity markets.

Table 5-23 shows RPM clearing prices for all RPM auctions held through 2018.

Figure 5-8 shows the RPM cleared MW weighted average prices for each LDA for the current delivery year and all results for auctions for future delivery years that have been held through 2018. A summary of these weighted average prices is given in Table 5-24.

Table 5-25 shows RPM revenue by resource type for all RPM auctions held through 2018 with $9.4 billion for new/repower/reactivated generation resources based on the unforced MW cleared and the resource clearing prices. A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM auctions.

Table 5-26 shows RPM revenue by calendar year for all RPM auctions held through 2018. In 2017, RPM revenue was $8.8 billion. In 2018, RPM revenue was $10.3 billion.

Table 5-27 shows the RPM annual charges to load. For the 2017/2018 Delivery Year, RPM annual charges to load are $9.1 billion. For the 2018/2019 Delivery Year, annual charges to load are $11.0 billion.

96 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

Table 5-23 Capacity market clearing prices: 2007/2008 through 2021/2022 RPM Auctions

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2007/2008 BRA		$40.80	$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$197.67	$188.54		$40.80	$188.54
2008/2009 BRA		$111.92	$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$148.80	$210.11		$111.92	$210.11
2008/2009 Third Incremental Auction		$10.00	$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$10.00	$223.85		$10.00	$223.85
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$191.32	$237.33		$102.04	$237.33
2009/2010 Third Incremental Auction		$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00		$40.00	$86.00
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29	$174.29		$174.29	$174.29
2010/2011 Third Incremental Auction		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00		$50.00	$50.00
2011/2012 BRA		$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00		$110.00	$110.00
2011/2012 First Incremental Auction		$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00		$55.00	$55.00
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$133.37	$139.73	$133.37	$222.30	$139.73	$185.00	$133.37		$16.46	$133.37
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$153.67	$16.46	$16.46	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$48.91	$13.01	$13.01	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$226.15	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	$27.73	$27.73	$226.15
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$178.85	$54.82	$20.00	$20.00	$54.82
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$10.00	$40.00	$10.00	$40.00	$40.00	$40.00	$10.00	$7.01	$7.01	$10.00
2013/2014 Third Incremental Auction		$4.05	$30.00	$4.05	$30.00	$188.44	$30.00	$188.44	$188.44	$188.44	$30.00	$4.05	$4.05	$30.00
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99	$125.99	$136.50
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99	$125.99	$136.50
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$5.23	$5.23	$399.62	$5.23	$0.03	$0.03	$5.23
2014/2015 First Incremental Auction	Extended Summer	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54	$5.54	$16.56
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54	$5.54	$16.56
2014/2015 Second Incremental Auction	Limited	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Second Incremental Auction	Extended Summer	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Second Incremental Auction	Annual	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Third Incremental Auction	Limited	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2014/2015 Third Incremental Auction	Extended Summer	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2014/2015 Third Incremental Auction	Annual	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62	$118.54	$150.00
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08	$136.00	$167.46
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00	$136.00	$167.46
2015/2016 First Incremental Auction	Limited	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 First Incremental Auction	Extended Summer	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 First Incremental Auction	Annual	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 Second Incremental Auction	Limited	$123.56	$141.12	$123.56	$141.12	$141.12	$141.12	$141.12	$155.02	$155.02	$141.12	$204.10	$123.56	$141.12
2015/2016 Second Incremental Auction	Extended Summer	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54	$136.00	$153.56
2015/2016 Second Incremental Auction	Annual	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54	$136.00	$153.56
2015/2016 Third Incremental Auction	Limited	$100.76	$122.33	$100.76	$122.33	$122.33	$122.33	$122.33	$122.56	$122.56	$122.33	$100.76	$100.76	$122.33
2015/2016 Third Incremental Auction	Extended Summer	$163.20	$184.77	$163.20	$184.77	$184.77	$184.77	$184.77	$185.00	$185.00	$184.77	$163.20	$163.20	$184.77
2015/2016 Third Incremental Auction	Annual	$163.20	$184.77	$163.20	$184.77	$184.77	$184.77	$184.77	$185.00	$185.00	$184.77	$163.20	$163.20	$184.77
2016/2017 BRA	Limited	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$94.45	$59.37	$119.13
2016/2017 BRA	Extended Summer	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23	$59.37	$119.13
2016/2017 BRA	Annual	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23	$59.37	$119.13
2016/2017 First Incremental Auction	Limited	$53.93	$89.35	$53.93	$89.35	$89.35	$89.35	$89.35	$214.44	$214.44	$89.35	$94.45	$53.93	$89.35
2016/2017 First Incremental Auction	Extended Summer	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52	$60.00	$119.13
2016/2017 First Incremental Auction	Annual	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52	$60.00	$119.13
2016/2017 Second Incremental Auction	Limited	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Second Incremental Auction	Extended Summer	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Second Incremental Auction	Annual	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Capacity Performance Transition Auction	Capacity Performance	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00
2016/2017 Third Incremental Auction	Limited	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2016/2017 Third Incremental Auction	Extended Summer	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2016/2017 Third Incremental Auction	Annual	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2017/2018 BRA	Limited	$106.02	$106.02	$106.02	$40.00	$106.02	$106.02	$106.02	$201.02	$201.02	$106.02	$106.02	$106.02	$106.02
2017/2018 BRA	Extended Summer	$120.00	$120.00	$120.00	$53.98	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
2017/2018 BRA	Annual	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
2017/2018 Capacity Performance Transition Auction	Capacity Performance	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50
2017/2018 First Incremental Auction	Limited	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Extended Summer	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Annual	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 Second Incremental Auction	Limited	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Second Incremental Auction	Extended Summer	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Second Incremental Auction	Annual	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Third Incremental Auction	Limited	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2017/2018 Third Incremental Auction	Extended Summer	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2017/2018 Third Incremental Auction	Annual	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2018/2019 BRA	Base Capacity	$149.98	$149.98	$149.98	$75.00	$210.63	$149.98	$210.63	$210.63	$210.63	$149.98	$149.98	$200.21	$149.98
2018/2019 BRA	Base Capacity DR/EE	$149.98	$149.98	$149.98	$75.00	$210.63	$59.95	$210.63	$210.63	$210.63	$41.09	$149.98	$200.21	$59.95
2018/2019 BRA	Capacity Performance	$164.77	$164.77	$164.77	$164.77	$225.42	$164.77	$225.42	$225.42	$225.42	$164.77	$164.77	$215.00	$164.77
2018/2019 First Incremental Auction	Base Capacity	$22.51	$22.51	$22.51	$22.51	$80.04	$22.51	$35.68	$80.04	$80.04	$22.51	$22.51	$25.36	$22.51
2018/2019 First Incremental Auction	Base Capacity DR/EE	$22.51	$22.51	$22.51	$22.51	$80.04	$22.51	$35.68	$80.04	$80.04	$22.51	$22.51	$25.36	$22.51
2018/2019 First Incremental Auction	Capacity Performance	$27.15	$27.15	$27.15	$27.15	$84.68	$27.15	$84.68	$84.68	$84.68	$27.15	$27.15	$30.00	$27.15
2018/2019 Second Incremental Auction	Base Capacity	$5.00	$5.00	$5.00	$5.00	$35.02	$5.00	$30.00	$35.02	$35.02	$5.00	$5.00	$5.00	$5.00
2018/2019 Second Incremental Auction	Base Capacity DR/EE	$5.00	$5.00	$5.00	$5.00	$35.02	$5.00	$30.00	$35.02	$35.02	$5.00	$5.00	$5.00	$5.00
2018/2019 Second Incremental Auction	Capacity Performance	$50.00	$50.00	$50.00	$50.00	$80.02	$50.00	$80.02	$80.02	$80.02	$50.00	$50.00	$50.00	$50.00
2018/2019 Third Incremental Auction	Base Capacity	$14.29	$14.29	$14.29	$14.29	$19.30	$14.29	$5.00	$19.30	$19.30	$14.29	$14.29	$14.29	$3.50
2018/2019 Third Incremental Auction	Base Capacity DR/EE	$14.29	$14.29	$14.29	$14.29	$19.30	$14.29	$5.00	$19.30	$19.30	$14.29	$14.29	$14.29	$3.50
2018/2019 Third Incremental Auction	Capacity Performance	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99
2019/2020 BRA	Base Capacity	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$80.00	$80.00	$182.77	$80.30
2019/2020 BRA	Base Capacity DR/EE	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$0.01	$80.00	$182.77	$80.30

Table 5-23 Capacity market clearing prices: 2007/2008 through 2021/2022 RPM Auctions (continued)

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2019/2020 First Incremental Auction	Base Capacity	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Base Capacity DR/EE	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Capacity Performance	$51.33	$51.33	$51.33	$51.33	$58.55	$51.33	$58.55	$58.55	$58.55	$51.33	$51.33	$51.33	$51.33
2019/2020 Second Incremental Auction	Base Capacity	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14
2019/2020 Second Incremental Auction	Base Capacity DR/EE	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14
2019/2020 Second Incremental Auction	Capacity Performance	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$55.00
2020/2021 BRA	Capacity Performance	$76.53	$86.04	$76.53	$86.04	$187.87	$86.04	$187.87	$187.87	$187.87	$86.04	$76.53	$188.12	$86.04
2020/2021 First Incremental Auction	Capacity Performance	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30

Table 5-24 Weighted average clearing prices by zone: 2018/2019 through 2021/2022

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2018/2019	2019/2020	2020/2021	2021/2022
RTO				
AEP	$158.20	$95.57	$75.83	$140.05
APS	$158.20	$95.57	$75.83	$140.05
ATSI	$148.42	$94.74	$74.98	$171.32
Cleveland	$158.68	$95.36	$72.16	$171.33
ComEd	$199.02	$194.82	$184.32	$195.55
DAY	$158.20	$95.57	$75.83	$140.05
DEOK	$158.20	$95.57	$75.83	$140.05
DLCO	$158.20	$95.57	$75.83	$140.05
Dominion	$158.20	$95.57	$75.83	$140.05
EKPC	$158.20	$95.57	$75.83	$140.05
MAAC				
EMAAC				
AECO	$214.31	$113.49	$186.61	$165.68
DPL	$214.31	$113.49	$186.61	$165.68
DPL South	$211.38	$116.08	$184.53	$165.73
JCPL	$214.31	$113.49	$186.61	$165.68
PECO	$214.31	$113.49	$186.61	$165.68
PSEG	$210.92	$116.35	$187.39	$204.20
PSEG North	$211.71	$116.64	$186.33	$204.27
RECO	$214.31	$113.49	$186.61	$165.68
SWMAAC				
BGE	$141.58	$93.53	$85.24	$199.00
Pepco	$144.90	$91.46	$85.54	$140.00
WMAAC				
Met-Ed	$152.65	$96.38	$85.16	$140.00
PENELEC	$152.65	$96.38	$85.16	$140.00
PPL	$147.90	$95.36	$85.70	$140.08

Table 5-25 RPM revenue by type: 2007/2008 through 2021/2022[97] [98]

				Coal		Gas		Hydroelectric	
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated
2007/2008	$5,537,085	$0	$22,225,980	$1,019,060,206	$0	$1,625,158,046	$3,516,075	$209,490,444	$0
2008/2009	$35,349,116	$0	$60,918,903	$1,835,059,769	$0	$2,115,862,522	$9,784,064	$287,838,147	$12,255
2009/2010	$65,762,003	$0	$56,517,793	$2,409,315,953	$1,854,781	$2,551,967,501	$30,168,831	$364,731,344	$11,173
2010/2011	$60,235,796	$0	$106,046,871	$2,648,278,766	$3,168,069	$2,829,039,737	$58,065,964	$442,410,730	$19,085
2011/2012	$55,795,785	$139,812	$185,421,273	$1,586,775,249	$28,330,047	$1,721,272,563	$98,448,693	$278,529,660	$0
2012/2013	$264,387,897	$11,408,552	$13,260,822	$1,014,858,378	$7,568,127	$1,256,600,367	$76,633,409	$179,117,374	$11,998
2013/2014	$558,715,114	$21,598,174	$31,804,645	$1,741,613,525	$12,950,135	$2,154,401,813	$167,844,235	$308,853,673	$25,708
2014/2015	$681,315,139	$42,308,549	$135,573,409	$1,935,468,356	$57,078,818	$2,176,442,220	$205,555,569	$333,941,614	$6,649,774
2015/2016	$903,496,003	$66,652,986	$260,806,674	$2,902,870,267	$63,682,708	$2,676,692,075	$535,039,154	$389,540,948	$15,478,144
2016/2017	$466,952,356	$68,709,670	$244,091,507	$2,137,545,515	$72,217,195	$2,217,027,225	$667,098,133	$283,613,426	$13,927,638
2017/2018	$515,145,457	$86,147,605	$218,710,769	$2,452,687,763	$62,790,145	$2,550,970,172	$984,733,791	$348,972,234	$15,219,121
2018/2019	$637,742,320	$103,105,796	$263,475,004	$2,637,322,434	$77,072,397	$2,992,482,882	$1,444,760,231	$416,075,805	$15,382,098
2019/2020	$372,756,931	$89,249,885	$83,736,046	$1,655,571,636	$47,528,002	$1,949,596,494	$1,058,669,656	$247,843,671	$6,208,824
2020/2021	$343,544,146	$93,092,140	$74,256,199	$1,318,324,680	$36,115,158	$2,080,256,094	$1,146,062,527	$209,060,912	$7,737,607
2021/2022	$631,409,762	$166,627,498	$130,197,690	$2,079,667,778	$66,256,260	$2,670,256,030	$1,676,705,702	$295,309,520	$11,589,480

	Nuclear		Oil		Solar		Solid waste	
	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated
2007/2008	$996,085,233	$0	$339,272,020	$0	$0	$0	$31,512,230	$0
2008/2009	$1,322,601,837	$0	$375,774,257	$4,837,523	$0	$0	$35,011,991	$0
2009/2010	$1,517,723,628	$0	$447,358,085	$5,676,582	$0	$0	$42,758,762	$523,739
2010/2011	$1,799,258,125	$0	$440,593,115	$4,339,539	$0	$0	$40,731,606	$413,503
2011/2012	$1,079,386,338	$0	$263,061,402	$967,887	$0	$66,978	$25,636,836	$261,690
2012/2013	$762,719,550	$0	$248,107,065	$2,772,987	$0	$1,246,337	$26,840,670	$316,420
2013/2014	$1,346,223,419	$0	$385,720,626	$5,670,399	$0	$3,523,555	$43,943,130	$1,977,705
2014/2015	$1,464,950,862	$0	$319,758,617	$4,106,697	$0	$3,836,582	$34,281,137	$1,709,533
2015/2016	$1,850,033,226	$0	$397,556,965	$5,947,275	$0	$7,064,983	$35,862,368	$6,179,607
2016/2017	$1,483,759,630	$0	$261,495,016	$4,030,823	$0	$7,057,256	$32,648,789	$6,380,604
2017/2018	$1,694,447,711	$0	$276,148,715	$3,888,126	$0	$10,899,883	$34,771,100	$9,036,976
2018/2019	$2,004,607,689	$0	$339,771,633	$2,922,855	$0	$16,928,323	$38,243,467	$9,658,138
2019/2020	$1,275,670,828	$0	$185,300,298	$1,723,692	$0	$11,954,557	$21,205,162	$5,326,702
2020/2021	$1,421,992,631	$0	$212,589,855	$1,408,492	$0	$7,389,376	$26,917,827	$5,428,707
2021/2022	$1,181,920,902	$0	$253,987,440	$2,401,396	$0	$29,673,108	$31,924,862	$7,757,690

	Wind		
	Existing	New/repower/ reactivated	Total revenue
2007/2008	$430,065	$0	$4,252,287,381
2008/2009	$1,180,153	$2,917,048	$6,087,147,586
2009/2010	$2,011,156	$6,836,827	$7,503,218,157
2010/2011	$1,819,413	$15,232,177	$8,449,652,496
2011/2012	$1,072,929	$9,919,881	$5,335,087,023
2012/2013	$812,644	$5,052,036	$3,871,714,635
2013/2014	$1,373,205	$13,538,988	$6,799,778,047
2014/2015	$1,524,551	$32,766,219	$7,437,267,646
2015/2016	$1,829,269	$42,994,253	$10,161,726,902
2016/2017	$1,144,873	$26,189,042	$7,993,888,695
2017/2018	$1,529,251	$40,577,901	$9,306,676,719
2018/2019	$1,166,553	$54,226,228	$11,054,943,851
2019/2020	$756,891	$45,598,006	$7,058,697,281
2020/2021	$25,124	$35,671,349	$7,019,872,821
2021/2022	$2,089,282	$63,102,701	$9,300,877,101

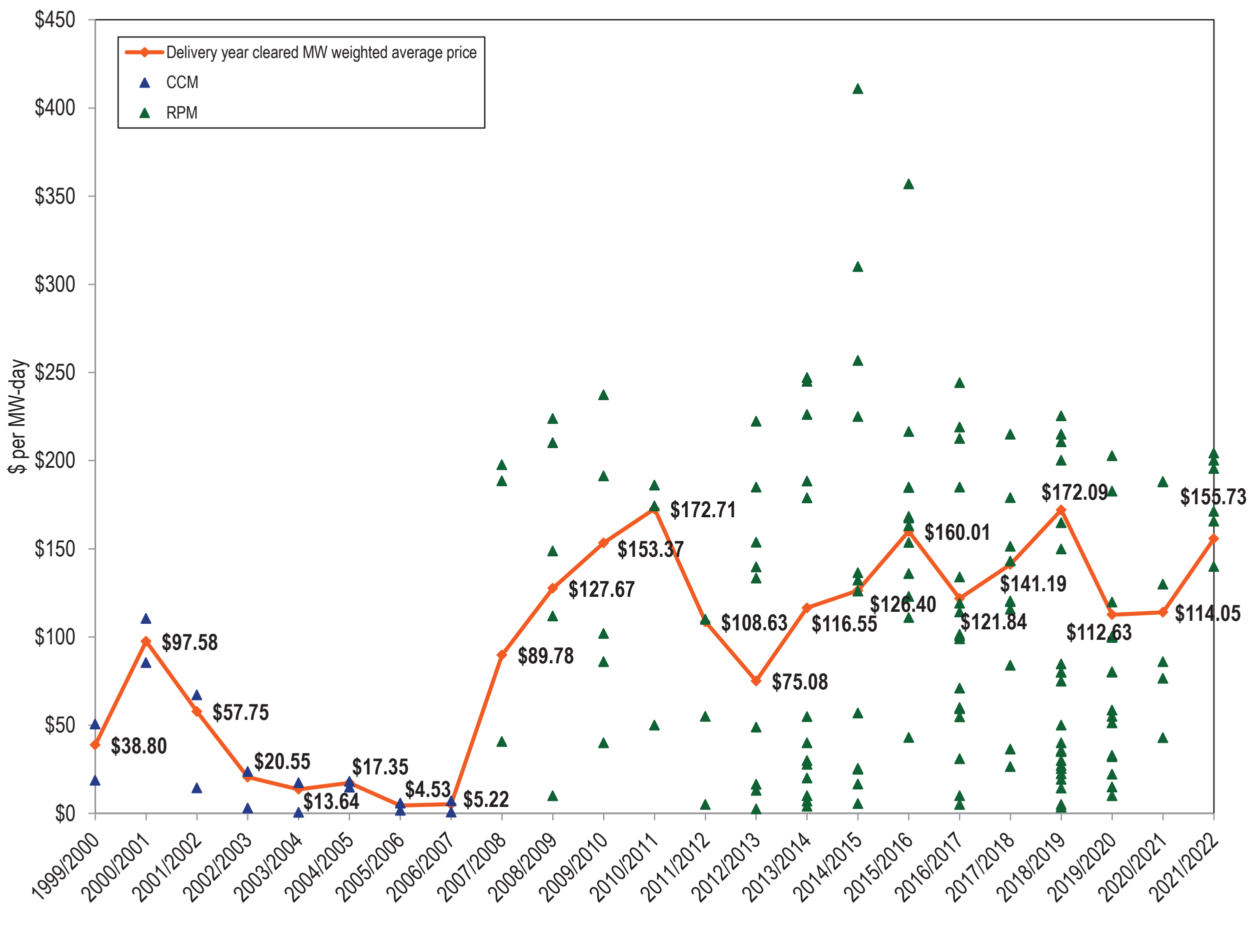
97 A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.

98 The results for the ATSI Integration Auctions are not included in this table.

Table 5-26 RPM revenue by calendar year: 2007 through 2022[99]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	129,409.2	214	$2,486,310,108
2008	$111.93	130,223.2	366	$5,334,880,241
2009	$142.74	132,772.0	365	$6,917,391,702
2010	$164.71	134,033.9	365	$8,058,113,907
2011	$135.14	134,105.2	365	$6,615,032,130
2012	$89.01	137,684.7	366	$4,485,656,150
2013	$99.39	154,044.3	365	$5,588,442,225
2014	$122.32	160,668.7	365	$7,173,539,072
2015	$146.10	169,112.0	365	$9,018,343,604
2016	$137.69	176,742.6	366	$8,906,998,628
2017	$133.19	180,272.0	365	$8,763,578,112
2018	$159.31	177,680.6	365	$10,331,688,133
2019	$137.23	173,706.1	365	$8,700,631,571
2020	$113.46	169,707.2	366	$7,047,241,889
2021	$138.49	165,333.1	365	$8,357,228,755
2022	$155.73	163,627.3	151	$3,847,760,116

Figure 5-7 History of capacity prices: 1999/2000 through 2021/2022[100]



99 The results for the ATSI Integration Auctions are not included in this table.

100 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2021/2022 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM resource clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-8 Map of RPM capacity prices: 2018/2019 through 2021/2022

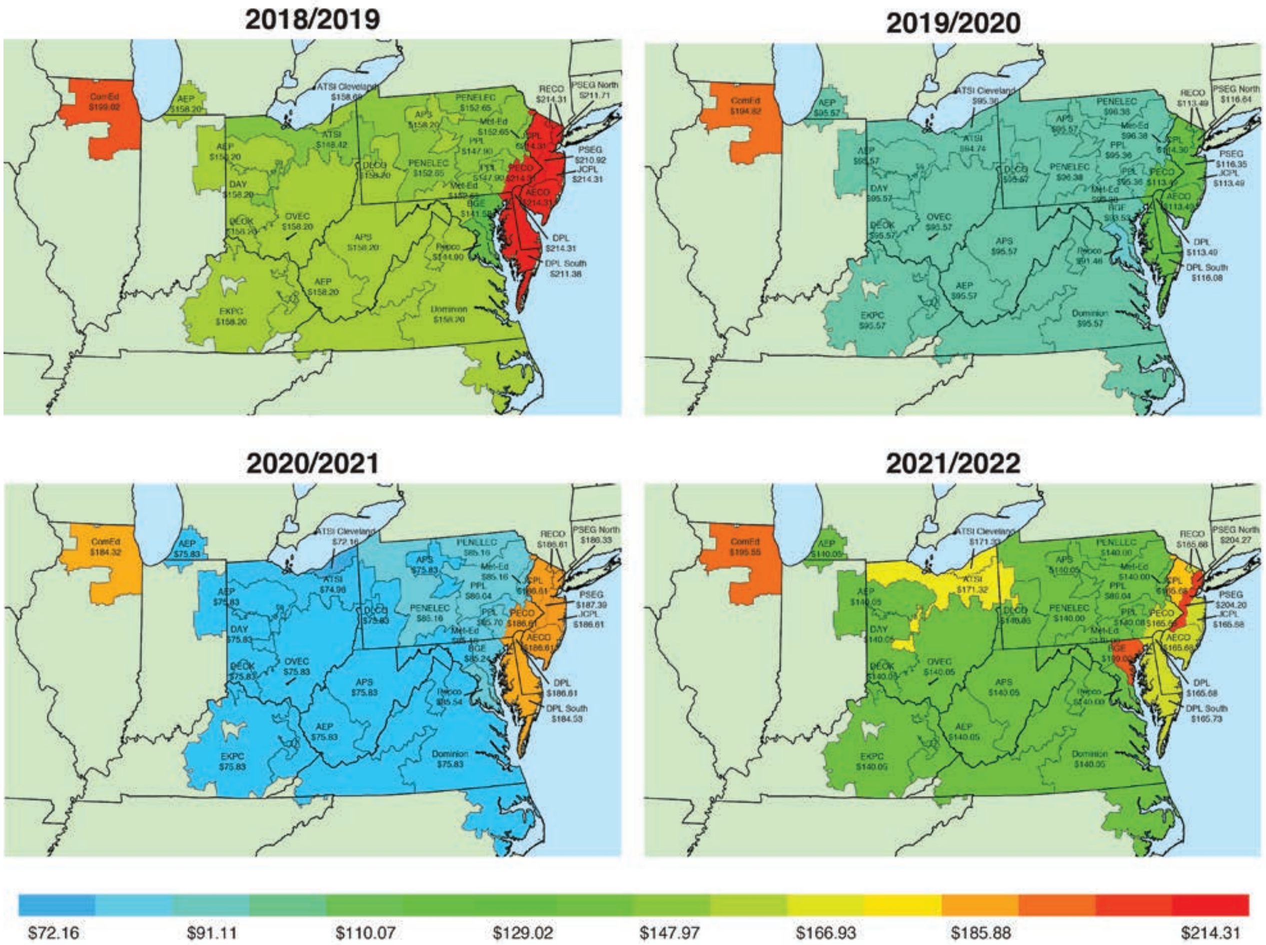


Table 5-27 RPM cost to load: 2017/2018 through 2021/2022 RPM Auctions[101 102 103]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2017/2018			
Rest of RTO	$153.61	94,874.5	$5,319,445,392
Rest of MAAC	$153.74	44,352.0	$2,488,734,815
PSEG	$208.59	10,932.0	$832,333,767
PPL	$151.86	7,935.5	$439,869,055
Total		158,094.0	$9,080,383,029
2018/2019			
Rest of RTO	$164.70	80,837.7	$4,859,734,465
Rest of MAAC	$218.98	31,118.9	$2,487,249,930
BGE	$158.20	7,701.4	$444,710,759
DPL	$219.29	4,463.7	$357,277,053
ComEd	$212.03	24,752.4	$1,915,591,298
Pepco	$156.90	7,329.2	$419,746,111
PPL	$155.11	8,300.9	$469,969,694
Total		164,504.2	$10,954,279,310
2019/2020			
Rest of RTO	$98.01	89,481.5	$3,209,816,762
Rest of EMAAC	$115.68	24,189.5	$1,024,134,241
BGE	$97.72	7,609.2	$272,145,810
ComEd	$191.70	25,196.6	$1,767,877,460
Pepco	$92.80	7,281.3	$247,297,867
PSEG	$115.93	11,169.9	$473,945,328
Total		164,928.0	$6,995,217,469
2020/2021			
Rest of RTO	$77.00	69,538.0	$1,954,438,669
Rest of MAAC	$86.89	29,572.5	$937,886,000
Rest of EMAAC	$176.17	34,949.0	$2,247,251,699
ComEd	$183.79	25,040.0	$1,679,743,111
DEOK	$103.53	5,208.1	$196,815,744
Total		164,307.7	$7,016,135,223
2021/2022			
Rest of RTO	$140.53	82,080.4	$4,210,274,861
Rest of EMAAC	$163.08	23,762.8	$1,414,495,718
ATSI	$157.99	14,464.9	$834,165,114
BGE	$161.62	7,435.0	$438,596,021
ComEd	$192.69	24,983.0	$1,757,064,009
PSEG	$184.03	10,901.1	$732,248,951
Total		163,627.3	$9,386,844,675

101 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM Auction results.

102 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone.

103 Prior to the 2009/2010 Delivery Year, the final UCAP obligation is determined after the clearing of the Second Incremental Auction. For the 2009/2010 through 2011/2012 Delivery Years, the final UCAP obligations are determined after the clearing of the Third Incremental Auction. Effective with the 2012/2013 Delivery Year, the final UCAP obligation is determined after the clearing of the final Incremental Auction. Prior to the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after certification of ILR. Effective with the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after the final Incremental Auction. The 2019/2020, 2020/2021, and 2021/2022 Net Load Prices are not finalized. The 2019/2020, 2020/2021, and 2021/2022 obligation MW are not finalized.

Reliability Must Run (RMR) Service

PJM must make out of market payments to units for Reliability Must Run (RMR) service during periods when a unit that would otherwise have been deactivated is needed for reliability.[104] The need for RMR service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[105]

When notified of an intended deactivation, the Market Monitor performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[106] PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[107] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to provide RMR service.[108] The PJM market rules do not require an owner to provide RMR service, but owners must provide 90 days advance notice of a proposed deactivation.[109] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[110] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction, an owner must show "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM, 120 days prior to such auction.[111]

104 OATT Part V.

105 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").

106 OATT § 113.2; OATT Attachment M § IV.1.

107 OATT § 113.2.

108 *Id.*

109 OATT § 113.1.

110 OATT Attachment DD § 6.6(g).

111 *Id.*

Under the current rules, a unit providing RMR service can recover its costs under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[112] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit." [113] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[114] The rules provide terms for early termination of RMR service and for the repayment of project investment by owners of units that choose to keep units in service after the RMR period ends.[115] Project investment is capped at $2 million, above which FERC approval is required.[116] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC. [117]

Table 5-28 shows units that have provided or are providing RMR service to PJM.

In each of the cost of service recovery rate filings for RMR service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the RMR service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to establish a rate base including investment in the existing plant and new investment necessary to provide RMR service and to earn a return on that rate base and receive depreciation of that rate base. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the RMR service period and have included costs incurred prior to the decision to the deactivate.[118] In one cost of service recovery rate, the filing included costs that already had been written off on the company's public books.[119] Unit owners have filed for revenues under the cost of service method that substantially exceed the actual incremental costs of providing RMR service.

Table 5-28 RMR service summary

Unit Names	Owner	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
B.L. England 2	RC Cape May Holdings, LLC	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	31-May-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
B.L. England 3	RC Cape May Holdings, LLC	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

Only two of seven owners have used the deactivation avoidable cost rate approach. The other five owners used the cost of service recovery rate, despite the greater administrative expense.

Because an RMR unit is needed by PJM for reliability reasons, and the provision of RMR service is voluntary

112 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Adder) * MW capability of the unit * Number of days in the month) – Actual Net Revenues).
113 OATT § 115.
114 *Id.*
115 OATT § 118.
116 OATT §§ 115, 117.
117 OATT § 119.
118 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000.
119 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.

in PJM, owners of RMR service have significant market power in establishing the terms of RMR service.

RMR service should be provided to PJM customers at reasonable rates, which reflect the riskless nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual costs incurred to provide the service plus an incentive markup.

The cost of service recovery rates have been excessive compared to the actual costs of providing RMR service. The DACR method also provides excessive incentives for service longer than a year, given that customers bear the risks.

The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V.

The MMU also recommends, based in part on its experience with application of the deactivation avoidable cost rate and proceedings filed under Section 119, the following improvements to the DACR provisions:

- Revise the applicable adders in Section 114 to be 15 percent for the second year of RMR service and 20 percent for the provision of RMR service in excess of two years.
- Add true up provisions that ensure that the RMR service provider is reimbursed for, and consumers pay for, the actual costs associated with the RMR service, plus the applicable adder.
- Eliminate the $2 million cap on project investment expenditures.
- Clearly distinguish operating expenses and project investment costs.
- Clarify the tariff language in Section 118 regarding the refund of project investment in the event the RMR unit continues operation beyond the RMR term.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-29 shows the capacity factors by unit type for 2017 and 2018. In 2018, nuclear units had a capacity factor of 94.2 percent, compared to 94.1 percent in 2017; combined cycle units had a capacity factor of 60.0 percent in 2018, compared to a capacity factor of 58.4 percent in 2017; all steam units had a capacity factor of 39.0 percent in 2018, compared to 40.8 percent in 2017; coal units had a capacity factor of 44.4 percent in 2018, compared to 46.6 percent in 2017.

Table 5-29 Capacity factor (By unit type (GWh)): 2017 and 2018[120 121]

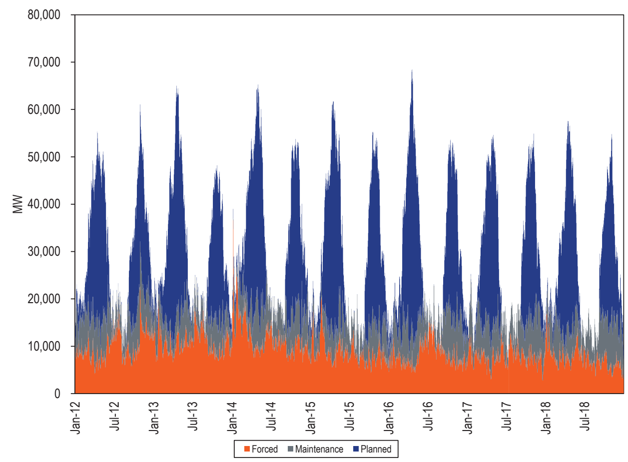
	2017		2018		Change in
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	2018 from 2017
Battery	25.1	0.9%	14.3	0.6%	(0.3%)
Combined Cycle	195,631.7	58.4%	234,614.7	60.0%	1.5%
Single Fuel	159,214.6	62.6%	194,921.2	63.5%	0.9%
Dual Fuel	36,417.1	45.1%	39,693.5	47.1%	2.0%
Combustion Turbine	13,384.9	5.3%	17,590.9	6.9%	1.7%
Single Fuel	9,708.0	5.1%	11,810.7	6.3%	1.2%
Dual Fuel	3,676.8	5.7%	5,780.2	8.7%	3.0%
Diesel	322.3	10.1%	351.8	10.4%	0.3%
Single Fuel	314.3	11.1%	341.9	11.4%	0.2%
Dual Fuel	8.1	2.2%	9.9	2.7%	0.5%
Diesel (Landfill gas)	1,727.7	51.6%	1,712.8	51.8%	0.2%
Fuel Cell	226.7	86.2%	225.9	82.9%	(3.4%)
Nuclear	287,575.8	94.1%	286,155.4	94.2%	0.0%
Pumped Storage Hydro	6,475.4	14.6%	7,004.9	15.8%	1.2%
Run of River Hydro	8,393.0	32.0%	12,410.6	46.8%	14.8%
Solar	1,463.1	17.0%	2,104.9	17.7%	0.7%
Steam	272,282.7	40.8%	253,826.7	39.0%	(1.8%)
Biomass	5,859.6	59.3%	6,451.9	68.6%	9.2%
Coal	258,498.3	46.6%	241,022.0	44.4%	(2.2%)
Single Fuel	252,866.1	48.6%	235,262.5	45.8%	(2.8%)
Dual Fuel	5,632.2	16.6%	5,759.5	19.6%	3.0%
Natural Gas	7,770.2	9.3%	5,987.5	7.5%	(1.8%)
Single Fuel	678.6	7.1%	637.8	8.0%	0.9%
Dual Fuel	7,091.6	9.6%	5,349.7	7.4%	(2.1%)
Oil	154.6	0.8%	365.2	1.9%	1.2%
Wind	20,714.1	29.5%	21,626.8	28.4%	(1.1%)
Total	808,228.0	47.0%	837,644.2	47.4%	0.4%

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The MW on outage vary throughout the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-9, due to restrictions on planned outages during the winter and summer. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-12.

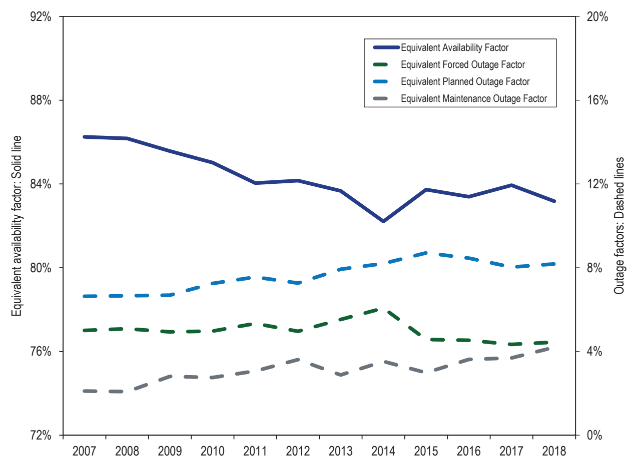
Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

Figure 5-9 Outages (MW): 2012 through 2018



The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-10. Metrics by unit type are shown in Table 5-30.

Figure 5-10 Equivalent outage and availability factors: 2007 to 2018



120 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

121 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.

Table 5-30 EFOF, EPOF, EMOF and EAF by unit type: 2007 through 2018

	Coal				Combined Cycle				Combustion Turbine				Diesel			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7.7%	8.7%	2.8%	80.8%	2.4%	6.1%	1.8%	89.7%	4.7%	2.5%	2.7%	90.1%	10.2%	0.6%	1.6%	87.6%
2008	7.8%	7.5%	2.5%	82.2%	2.2%	6.0%	1.7%	90.1%	2.8%	4.1%	2.3%	90.7%	9.1%	1.0%	1.2%	88.7%
2009	6.8%	8.7%	3.6%	81.0%	2.7%	5.8%	3.2%	88.3%	1.5%	2.8%	2.5%	93.3%	6.6%	0.6%	1.1%	91.7%
2010	7.8%	8.9%	4.1%	79.2%	2.1%	7.9%	2.7%	87.3%	2.0%	2.8%	2.1%	93.1%	4.4%	0.4%	1.5%	93.6%
2011	8.3%	8.4%	4.5%	78.9%	2.3%	8.4%	2.1%	87.2%	2.1%	3.7%	2.4%	91.8%	3.3%	0.1%	1.8%	94.8%
2012	7.3%	8.5%	5.8%	78.4%	3.8%	8.2%	2.1%	86.0%	2.9%	3.1%	1.8%	92.2%	3.9%	0.7%	2.4%	93.1%
2013	8.6%	9.9%	4.5%	77.1%	2.5%	8.3%	2.2%	87.0%	5.2%	4.0%	1.8%	89.1%	6.0%	0.3%	1.4%	92.4%
2014	9.4%	9.1%	5.5%	76.0%	2.7%	9.4%	2.5%	85.4%	6.3%	4.0%	1.9%	87.9%	13.8%	0.4%	2.2%	83.5%
2015	7.7%	9.5%	4.5%	78.3%	2.2%	10.5%	2.0%	85.3%	2.9%	4.2%	2.5%	90.4%	7.6%	0.3%	2.7%	89.4%
2016	8.4%	8.7%	6.3%	76.6%	2.9%	10.9%	1.8%	84.4%	2.2%	5.3%	2.7%	89.8%	5.2%	0.2%	2.6%	92.0%
2017	9.5%	9.7%	6.9%	73.9%	1.9%	10.8%	1.6%	85.7%	1.4%	5.8%	2.0%	90.8%	6.5%	0.3%	2.0%	91.1%
2018	9.6%	10.9%	8.1%	71.4%	1.6%	9.4%	1.5%	87.6%	2.0%	5.5%	1.8%	90.8%	6.6%	0.9%	3.3%	89.2%

	Hydroelectric				Nuclear				Other			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	1.3%	7.2%	1.4%	90.1%	1.3%	5.3%	0.3%	93.1%	6.1%	7.6%	3.0%	83.3%
2008	1.3%	7.8%	2.1%	88.8%	1.8%	5.1%	0.8%	92.3%	8.6%	10.3%	3.1%	78.0%
2009	2.3%	8.7%	2.3%	86.8%	4.1%	5.2%	0.6%	90.1%	7.7%	7.6%	4.6%	80.0%
2010	0.7%	8.6%	1.9%	88.8%	2.3%	5.4%	0.5%	91.8%	8.1%	9.8%	3.5%	78.6%
2011	1.7%	11.7%	1.9%	84.7%	2.6%	6.1%	1.2%	90.1%	8.4%	10.8%	3.4%	77.3%
2012	2.8%	6.3%	2.1%	88.9%	1.5%	6.4%	1.1%	91.1%	8.0%	10.5%	5.0%	76.6%
2013	2.3%	7.8%	1.9%	87.9%	1.1%	5.9%	0.7%	92.2%	8.1%	10.7%	3.9%	77.4%
2014	2.5%	9.3%	3.0%	85.3%	1.8%	5.8%	0.9%	91.5%	7.2%	15.2%	5.4%	72.2%
2015	3.7%	9.6%	1.5%	85.2%	1.3%	5.5%	1.2%	91.9%	6.0%	17.2%	4.1%	72.7%
2016	2.6%	7.7%	3.1%	86.6%	1.7%	5.5%	1.2%	91.7%	4.7%	15.8%	4.4%	75.2%
2017	2.3%	5.8%	3.1%	88.9%	0.5%	5.1%	0.6%	93.7%	4.8%	9.3%	5.9%	80.0%
2018	2.5%	7.4%	3.6%	86.6%	0.8%	5.3%	0.6%	93.3%	5.1%	8.7%	7.9%	78.3%

Generator Forced Outage Rates

There are three primary forced outage rate metrics. The most fundamental forced outage rate metric is EFORd. The other forced outage rate metrics either exclude some outages, XEFORd, or exclude some outages and exclude some time periods, EFORp. The other outage rate metrics will no longer be used under the capacity performance capacity market design.

The unadjusted forced outage rate of a generating unit is measured as the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[122] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for 2018 was 7.2 percent, an increase from 7.1 percent for 2017. Figure 5-11 shows the average EFORd since 1999 for all units in PJM.[123]

122 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

123 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2018 State of the Market Report for PJM*, Appendix A: "PJM Geography" for details.

Figure 5-11 Trends in the equivalent demand forced outage rate (EFORd): 1999 through 2018

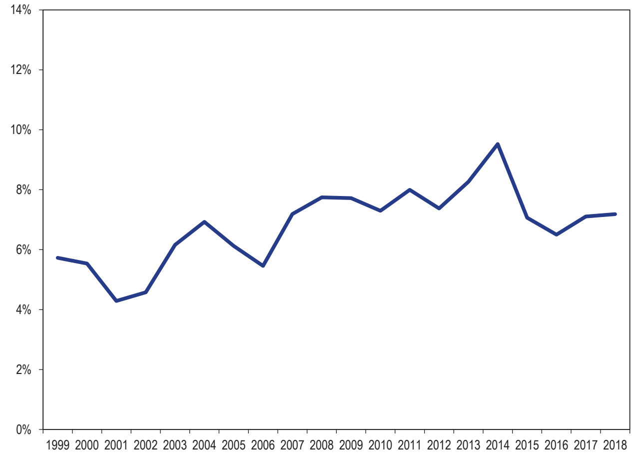


Table 5-31 shows the class average EFORd by unit type.

Table 5-31 EFORd data for different unit types: 2007 through 2018

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Coal	8.8%	8.9%	8.4%	9.4%	10.5%	9.7%	11.0%	11.8%	9.4%	10.4%	12.5%	13.1%
Combined Cycle	3.7%	3.5%	3.7%	2.7%	3.2%	4.5%	3.0%	4.5%	2.9%	3.7%	2.6%	2.3%
Combustion Turbine	11.7%	11.2%	9.8%	9.1%	8.3%	8.5%	11.1%	15.8%	9.2%	6.1%	5.9%	6.7%
Diesel	11.7%	10.3%	9.3%	6.4%	9.3%	5.1%	6.6%	14.8%	9.1%	7.2%	7.6%	7.2%
Hydroelectric	2.0%	2.0%	3.2%	1.2%	2.9%	4.4%	3.6%	3.8%	5.2%	3.7%	3.2%	3.2%
Nuclear	1.4%	1.9%	4.1%	2.5%	2.8%	1.6%	1.2%	1.9%	1.4%	1.9%	0.6%	0.8%
Other	11.1%	15.5%	14.3%	12.3%	14.9%	12.3%	15.5%	14.5%	13.0%	9.2%	13.8%	11.8%
Total	7.2%	7.7%	7.7%	7.3%	8.0%	7.4%	8.3%	9.5%	7.1%	6.5%	7.1%	7.2%

Other Forced Outage Rate Metrics

There are a number of performance incentives in the current capacity market design, but they fall short of the incentives that a unit would face if it earned all its revenue in an energy market. These incentives will change when the capacity performance capacity market design is implemented beginning with the 2018/2019 Delivery Year but remain essential reasons why the incentive components of capacity performance design were necessary.

Currently, there are two additional forced outage rate metrics that play a significant role in PJM markets, XEFORd and EFORp. Under the capacity performance modifications to RPM, neither XEFORd nor EFORp will be relevant.

The XEFORd metric is the EFORd metric adjusted to remove outages that have been defined to be outside management control (OMC). Under the capacity performance modifications to RPM, all outages will be included in the EFORd metric used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market, including the outages previously designated as OMC. OMC outages will no longer be excluded from the EFORd calculations.

The EFORp metric is the EFORd metric adjusted to remove OMC outages and to reflect unit availability only during the approximately 500 hours defined in the PJM RPM tariff to be the critical load hours. Under the capacity performance modifications to RPM, EFORp will no longer be used to calculate performance penalties.

Current PJM capacity market rules use XEFORd to determine the UCAP for generating units. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the XEFORd multiplied by the unit ICAP.

The current PJM capacity market rules create an incentive to minimize the forced outage rate excluding OMC outages, but not an incentive to minimize the forced outage rate accounting for all forced outages. In fact, because PJM uses XEFORd as the outage metric to define capacity available for sale, the current PJM Capacity Market includes an incentive to classify as many forced outages as possible as OMC. That incentive is removed in the capacity performance design.

Outages Deemed Outside Management Control

OMC outages will continue to be excluded from outage rate calculations through the end of the 2017/2018 Delivery Year. Under the capacity performance modifications to RPM, effective with the 2018/2019 Delivery Year, OMC outages will no longer be excluded from the EFORd metric used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. All forced outages will be included.[124]

124 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 5.B.

Table 5-32 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 1.2 percent of all forced outages in 2018. The largest contributor to OMC outages, wet coal, was the cause of 25.8 percent of OMC outages and 0.3 percent of all forced outages.

Table 5-32 OMC outages: 2018

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Wet coal	25.8%	0.3%
Other switchyard equipment	15.6%	0.2%
Switchyard circuit breakers	10.0%	0.1%
Other miscellaneous external problems	9.8%	0.1%
Flood	8.0%	0.1%
Transmission system problems other than catastrophes	6.1%	0.1%
Lack of fuel	5.9%	0.1%
Transmission line	5.1%	0.1%
Lightning	3.6%	0.0%
Switchyard transformers and associated cooling systems	2.6%	0.0%
Lack of water (hydro)	2.3%	0.0%
Transmission equipment	1.3%	0.0%
Storms	1.2%	0.0%
Switchyard system protection devices	1.1%	0.0%
Other fuel quality problems	0.9%	0.0%
Transmission equipment beyond the 1st substation	0.4%	0.0%
Low Btu coal	0.1%	0.0%
Other catastrophe	0.0%	0.0%
Regulatory	0.0%	0.0%
Hurricane	0.0%	0.0%
Total	100.0%	1.2%

Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[125] On a system wide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).[126]

PJM EFOF was 4.4 percent in 2018. This means there was 4.4 percent lost availability because of forced outages. Table 5-33 shows that forced outages for boiler tube leaks, at 18.8 percent of the system wide EFOF, were the largest single contributor to EFOF.

125 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a system wide basis.

126 EFOF incorporates all outages regardless of their designation as OMC.

Table 5-33 Contribution to EFOF by unit type by cause: 2018

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	24.4%	3.0%	0.0%	0.0%	0.0%	0.0%	14.8%	18.8%
Wet Scrubbers	10.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.7%
Boiler Air and Gas Systems	7.7%	0.0%	0.0%	0.0%	0.0%	0.0%	3.7%	5.8%
Unit Testing	4.6%	3.0%	10.1%	40.4%	6.1%	7.3%	8.2%	5.6%
Economic	0.5%	2.1%	7.1%	4.5%	2.9%	0.0%	33.5%	4.5%
Low Pressure Turbine	4.0%	0.7%	0.0%	0.0%	0.0%	0.0%	5.8%	3.4%
Feedwater System	3.2%	1.5%	0.0%	0.0%	0.0%	23.8%	1.1%	3.4%
Boiler Fuel Supply from Bunkers to Boiler	4.5%	0.4%	0.0%	0.0%	0.0%	0.0%	0.4%	3.2%
Miscellaneous (Generator)	2.4%	5.1%	10.6%	5.4%	4.1%	0.0%	2.4%	3.1%
Electrical	2.3%	4.2%	6.4%	1.4%	1.9%	2.7%	4.8%	3.0%
Miscellaneous (Pollution Control Equipment)	4.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.3%	2.9%
Intermediate Pressure Turbine	3.7%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	2.7%
Fuel Quality	3.5%	0.0%	0.2%	3.7%	0.0%	0.0%	0.9%	2.6%
Circulating Water Systems	2.0%	9.0%	0.0%	0.0%	0.0%	5.7%	2.2%	2.3%
Auxiliary Systems	1.1%	6.3%	11.2%	0.0%	0.3%	0.1%	0.9%	2.0%
Miscellaneous (Steam Turbine)	0.6%	18.6%	0.0%	0.0%	0.0%	8.0%	0.4%	1.8%
Boiler Tube Fireside Slagging or Fouling	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	1.7%
Boiler Piping System	1.9%	3.5%	0.0%	0.0%	0.0%	0.0%	1.3%	1.7%
Condensing System	1.8%	0.3%	0.0%	0.0%	0.0%	3.8%	0.3%	1.4%
All Other Causes	14.6%	42.3%	54.3%	44.5%	84.7%	48.6%	18.0%	22.6%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-34 shows the categories which are included in the economic category.[127] Lack of fuel that is considered outside management control accounted for 1.7 percent of all economic reasons.

OMC lack of fuel is described as "Lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."[128] Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

Table 5-34 Contributions to economic outages: 2018

	Contribution to Economic Reasons
Lack of fuel (Non-OMC)	93.7%
Fuel conservation	1.8%
Lack of fuel (OMC)	1.7%
Other economic problems	1.2%
Problems with primary fuel for units with secondary fuel operation	0.9%
Lack of water (hydro)	0.6%
Wet fuel (biomass)	0.2%
Ground water or other water supply problems	0.0%
Total	100.0%

EFORd, XEFORd and EFORp

The equivalent forced outage rate during peak hours (EFORp) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August. EFORp is calculated using historical performance data and is designed to measure if a unit would have run had the unit not been forced out. Like XEFORd, EFORp excludes OMC outages. PJM systemwide EFORp is a capacity-weighted average of individual unit EFORp.

127 The definitions of these outages are defined by NERC GADS.
128 The definitions of these outages are defined by NERC GADS.

Until the capacity performance market design is fully implemented for the 2020/2021 Delivery Year, EFORp will be used in the calculation of nonperformance charges for units that are not capacity performance capacity resources. Under capacity performance, EFORp will not be used.

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[129] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than XEFORd, suggesting that units elect to take non-OMC forced outages during off-peak hours, as much as it is within their ability to do so. That is consistent with the incentives created by the PJM Capacity Market but it does not directly address the question of the incentive effect of omitting OMC outages from the EFORp metric.

Table 5-35 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

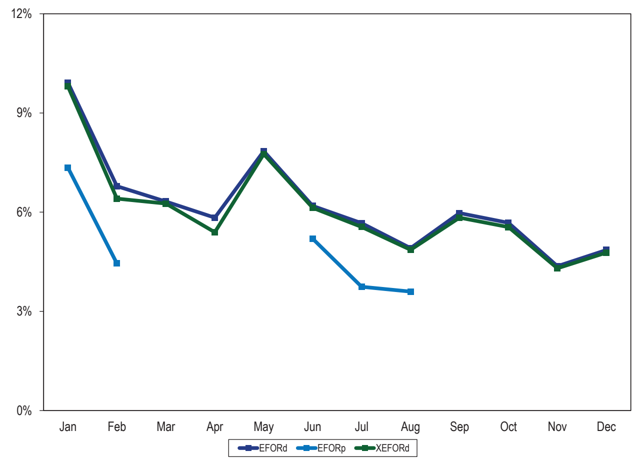
Table 5-35 EFORd, XEFORd and EFORp data by unit type: 2018[130]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Coal	13.1%	13.1%	10.0%	0.1%	3.1%
Combined Cycle	2.3%	2.2%	1.7%	0.0%	0.6%
Combustion Turbine	6.7%	6.3%	3.9%	0.4%	2.8%
Diesel	7.2%	6.9%	5.3%	0.2%	1.9%
Hydroelectric	3.2%	3.1%	2.1%	0.1%	1.1%
Nuclear	0.8%	0.8%	0.6%	0.0%	0.2%
Other	11.8%	11.1%	6.0%	0.7%	5.8%
Total	7.2%	7.0%	5.0%	0.2%	2.2%

Performance by Month

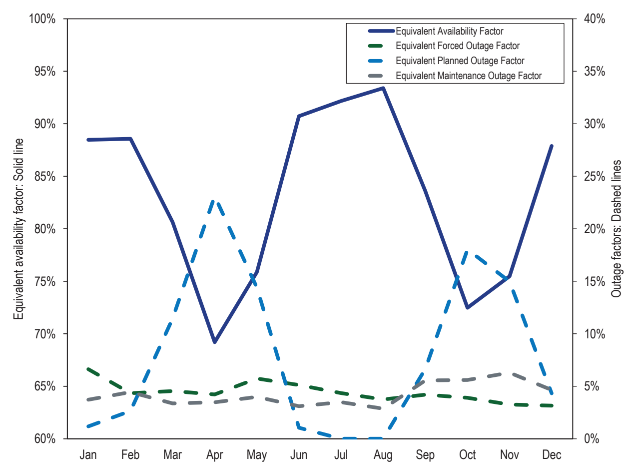
On a monthly basis, EFORp values were less than EFORd and XEFORd values as shown in Figure 5-12, demonstrating that units had fewer non-OMC outages during peak hours than would have been expected based on EFORd.

Figure 5-12 EFORd, XEFORd and EFORp: 2018



On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-13.

Figure 5-13 Monthly generator performance factors: 2018



129 See "PJM Manual 22: Generator Resource Performance Indices," § 2.0 Definitions, Rev. 17 (April 1, 2017).
130 EFORp is only calculated for the peak months of January, February, June, July and August.

Indiana Michigan Power Company
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Sierra Club 4th Set, Q7, Attachment 1

Forecasted ICAP
for Portion of Power Purchased by I&M from OVEC
(MW)

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
OVEC	171.7	171.7	171.7	171.7	169.7	167.7	165.8	165.8	167.7	169.7	171.7	171.7

	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
OVEC	171.7	171.7	171.7	171.7	169.7	167.7	165.8	165.8	167.7	169.7	171.7	171.7

	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
OVEC	171.7	171.7	171.7	171.7	169.7	167.7	165.8	165.8	167.7	169.7	171.7	171.7

	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
OVEC	171.7	171.7	171.7	171.7	169.7	167.7	165.8	165.8	167.7	169.7	171.7	171.7

	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
OVEC	171.7	171.7	171.7	171.7	169.7	167.7	165.8	165.8	167.7	169.7	171.7	171.7

Indiana Michigan Power Company
Case No. U-20804
Sierra Club 4th Set, Q7, Attachment 1

Forecasted ICAP
for Portion of Power Purchased by I&M from AEG
(MW)

Unit	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Rockport 1	462	462	462	462	462	460	460	460	462	462	462	462
Rockport 2	455	455	455	455	455	455	455	455	455	455	455	455

	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Rockport 1	462	462	462	462	462	460	460	460	462	462	462	660
Rockport 2	455	455	455	455	455	455	455	455	455	455	455	na

	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
Rockport 1	660	660	660	660	660	658	658	658	660	660	660	660
Rockport 2	na	na	na	na	na	na	na	na	na	na	na	na

	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Rockport 1	660	660	660	660	660	658	658	658	660	660	660	660
Rockport 2	na	na	na	na	na	na	na	na	na	na	na	na

	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
Rockport 1	660	660	660	660	660	658	658	658	660	660	660	660
Rockport 2	na	na	na	na	na	na	na	na	na	na	na	na

Indiana Michigan Power Company
Case No. U-20804
Sierra Club 4th Set, Q7, Attachment 1

Forecasted ICAP
for Portion of Power Purchased by I&M from AEG
(MW)

Unit	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Rockport 1	462	462	462	462	462	460	460	460	462	462	462	462
Rockport 2	455	455	455	455	455	455	455	455	455	455	455	455

	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Rockport 1	462	462	462	462	462	460	460	460	462	462	462	660
Rockport 2	455	455	455	455	455	455	455	455	455	455	455	na

	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
Rockport 1	660	660	660	660	660	658	658	658	660	660	660	660
Rockport 2	na	na	na	na	na	na	na	na	na	na	na	na

	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Rockport 1	660	660	660	660	660	658	658	658	660	660	660	660
Rockport 2	na	na	na	na	na	na	na	na	na	na	na	na

	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
Rockport 1	660	660	660	660	660	658	658	658	660	660	660	660
Rockport 2	na	na	na	na	na	na	na	na	na	na	na	na

Exhibit A

Benchmark Study Demonstrating that the Inter-Company Power Agreement Offers Low-Cost Power

At the request of the Ohio Valley Electric Corporation ("OVEC"), American Electric Power Service Corporation ("AEPSC") performed a benchmark study in support of the proposed 14-year extension of the term of the Inter-Company Power Agreement ("ICPA"), originally dated July 10, 1953 and as amended from time to time, among OVEC and the public utilities named therein as "Sponsoring Companies," which include several affiliates of AEPSC. As discussed below, it is clear the ICPA offers low-cost power to the Sponsoring Companies, taking into account both price and non-price factors.

A. Definition of the Relevant Market, Time Period and Products.

1. Relevant Geographic Market

Under Commission precedent, the relevant geographic market is the market where sellers can supply the relevant product to the purchasers under the subject contract.[1] This benchmark study defines the relevant geographic market broadly to include any supplier that is in the reliability regions governed by or under the following: (a) Reliability*First* Corporation ("RFC"), which is a consolidation of the three previous regions East Central Area Reliability Coordination Agreement ("ECAR"), the Mid-Atlantic Area Council ("MAAC") and the Mid-America Interconnected Network ("MAIN"), and (b) Midwest Reliability Organization ("MRO"), which regions collectively include the majority of the service territories of the regional transmission organizations of the PJM Interconnection, LLC ("PJM") and the Midwest Independent Transmission System Operator, Inc. ("MISO").

[1] *Ocean State Power II*, 59 FERC ¶ 61,360 at p. 62,333 (1992) ("*Ocean State*").

2. Contemporaneousness

The Commission defines the relevant period for these purposes as the period during which purchasers made their decisions to contract with the supplier.[2] Consequently, this benchmark study is based on a current forecast of generation alternatives through 2040, consistent with the extension period.

3. Comparable Products

The Commission generally requires that the evidence presented in benchmark studies compares transactions involving goods and services similar to those provided within the proposed transaction.[3] Accordingly, this benchmark study defines the relevant comparison to be the ICPA to the construction of base-load power plants over the same long-term time period, since the construction of a power plant is the most comparable alternative to entering into this long-term power supply agreement.

Other products such as power plant acquisitions and long-term power contracts were not considered comparable products since the proposed extension is for the time period March 14, 2026 through June 30, 2040. Such transactions would be near-term agreements that would not be comparable to an extension period that does not begin until 2026, in part since generally no market exists for offers that would provide beginning or closing dates in this timeframe. Construction start dates for new generation, on the other hand, are generally at the discretion of the purchaser, subject to permitting limitations and vendor availability.

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2 *See Electric Generation LLC*, 99 FERC ¶ 61,307, at p. 22 (2002).

3 *See Boston Edison Co. Re: Edgar Electric Energy Co.*, 55 FERC ¶ 61,382 at p. 62,169 (1991); *Ocean State*, 59 FERC at p. 62,333.

B. Summary of Benchmark Study

The benchmark study consists of a comparison of the IPCA for the extension period to construction of new base-load generation.

1. Costs to Construct New Power Plants

Based on information from the U.S. Energy Information Administration ("EIA") document, "*Table 1. Updated Estimates of Power Plant Capital and Operating Costs*". Release Date: November 2010, supplemented by operational assumptions and cost estimates from AEPSC internal sources, the estimated levelized cost of six different types of newly built central station base-load generation are shown on Schedule 1, page 1. The types of power plants reviewed include a new coal plant with flue gas desulphurization (i.e., "scrubbed"), integrated coal-gasification combined cycle (IGCC), with and without carbon capture and sequestration, advanced nuclear generation, and natural gas combined cycle (CC), with and without carbon sequestration. Other potential generation sources were excluded because they were not considered comparable, for example wind and solar, since they are intermittent, non-dispatchable resources.

As shown in Schedule 1, the installed cost of the comparable new units ranges from $1,003/kW for CC without carbon sequestration to $5,348/kW for IGCC with carbon sequestration. For comparison purposes, a typical annual carrying charge was applied to the estimated installed cost to reflect a reasonable amount for depreciation, taxes, administrative and general costs, and other expenses. Estimated fuel costs were also added, along with assumptions regarding the future average costs of carbon dioxide (CO_2) emissions and the ability of sequestration systems to capture the CO_2. These calculations resulted in average levelized total unit costs, including CO_2 costs, ranging from \$106 per MWh for a CC plant without carbon sequestration up to \$159.20/MWh for an IGCC plant with carbon sequestration. If CO_2 costs are ignored or assumed to be zero, the alternatives range from \$96.53/MWh for a new advance gas combined cycle plant to \$122.51 per MWh for an advanced nuclear plant.

As shown on Schedule 1, page 2, the average forecasted cost of the ICPA contract for the period 2011 through 2040 is \$84.23/MWh including CO_2 cost and \$60.90/MWh excluding CO_2 cost. These forecasts already include all of the carrying and operating costs associated with the planned environmental upgrades, including completion of Flue Gas Desulfurization for all Clifty Creek and Kyger Creek units and Selective Catalytic Reduction for Clifty Creek units 1-5 and Kyger Creek units 1-5.

For the cases including CO_2 costs, the cost of the ICPA is expected to be approximately 21% less than the least expensive alternative, the CC plant without carbon sequestration. For the cases excluding CO_2 costs, the ICPA is expected to be approximately 37% less than the least expensive alternative of the new CC plant.

It is recognized that the above values include the period from 2011 through 2040 for the ICPA even though the current request is for the period March 14, 2026 through June 30, 2040. No adjustments were made to attempt to project a near-term completion date and then "remove" the financial impacts of the new build options and the OVEC extension for the period prior to 2026. In practical terms, any such adjustment would require the implicit assumption that a counter-party could be identified that would be willing to purchase the output of the new plant at the fully-loaded cost in the interim period from the plant completion date until a termination date in 2026.

Likewise, forecasting a completion date for a new build option that did not begin commercial operation until 2026 would require the assumption of an unusual near-term commitment from the purchaser (and the vendor) in the near-term. In addition, this option would include a plant life period for the new-build generation that would extend well beyond the extension period termination of 2040. Presenting the proposed extension and the new build options on a levelized cost of electricity basis makes them comparable and mitigates the need for attempts at such adjustments. In addition, the ICPA analysis includes assumptions for the entire period that would potentially impact the cost in the current ICPA contract period.

One significant benefit of the ICPA is that it is expected to be the least cost alternative whether CO_2 costs are included or not. In comparing the CC without carbon sequestration alternative to the ICPA, the benefit of the ICPA, besides the expected discount indicated, is that the ICPA is not expected to carry the same price uncertainty for the fuel input, coal, as that of the CC plant, based on historic volatility associated with natural gas. Since neither of these options have carbon sequestration capability, the CC plant still carries approximately half the CO_2 emission risks as that associated with the ICPA. Furthermore, if forecasted CO_2 emissions cost are less than that included in this forecast, this result would tend to favor the ICPA even more than indicated above.

In a comparison with an advanced nuclear plant, the OVEC ICPA remains the least expensive option even when CO_2 costs are included. As CO_2 costs become less of a factor, or goes to zero, the ICPA discount becomes more comparable to either the natural gas CC or the advanced nuclear plant. In this case, the ICPA is less costly than the least expensive options identified, a new pulverized coal plant, which would have a similar CO_2 emission risk or the CC plant. Consequently, the ICPA clearly provides the most flexible choice with the highest degree of optionality in that it is the least cost option regardless of future CO_2 costs.

It should be noted further that the valuations contained herein that include CO_2 cost do not include any carbon cost offsets. Many types of proposed carbon programs include allocations of offsets, allowances or other phase-in programs that will reduce the carbon costs, at least in the initial years of such a program. No such assumptions are included in the above comparisons, and if they were, the OVEC extension would appear even more favorable compared with other, less carbon-intensive options.

2. Analysis of Non-Price Terms

The Commission also requires an assessment of non-price terms and conditions.[4] AEPSC performed a comparative analysis of specific non-price terms and conditions where such data was available. Specifically, for power plant sales and new-build power plants, the relevant non-price terms and conditions include: (1) availability, (2) dispatchability, (3) fuel price risk, and (4) project development risk. In general, the ICPA contains favorable non-price terms.

a. Availability

The availability of a power plant is a key measure of the reliability of any generating facility.[5] It is an indicator of the potential of a generating resource to meet load requirements and support system reliability. Availability also is a key contract indicator for measuring performance. The OVEC generating facilities have an excellent record of

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4 *Ocean State*, 59 FERC at p. 62,337.

5 *See Electric Generation, LLC*, 101 FERC ¶ 63,005 (2002).

performance based on availability factors. The availability factor for OVEC's Clifty Creek Plant was 85.0% in 2008, 87.1% in 2009 and 83.8% in 2010, while the availability factor for its Kyger Creek Plant was 85.4% in 2008, 84.3% in 2009 and 84.0% in 2010.

b. Dispatchability

Under the ICPA, the Sponsoring Companies have the right to schedule their proportionate share of the full available capacity and energy output of OVEC's generating facilities, subject to scheduling procedures developed by OVEC's Operating Committee.

c. Fuel Price Risk

Fuel costs associated with OVEC's coal-fired generating facilities may increase over the proposed extension of the term of the ICPA, thereby increasing costs to the Sponsoring Companies. However, with respect to construction of comparable units, the purchasers would be subject to the similar cost increases due to fluctuations in fuel prices.

d. Project Development Risk

The Sponsoring Companies are insulated against development risk under the ICPA, as compared to the new construction option, because the OVEC units have already been built and operating for many years.

C. Conclusion

Based on the benchmark study, the charges under the ICPA compare favorably to data concerning prices obtained through review of comparable information for other new generation base load options. The ICPA offers low-cost power to the Sponsoring Companies, taking into account both price and non-price factors.

Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Technology	Online Year	Size (MW)	Lead time (years)	Overnight Cost (2010 $/kW)	Variable O&M (2010 $/MWh)	Fixed O&M (2010 $/kW)	Heat Rate (Btu/kWhr)	Levelized Cost of Electricty (COE) Including CO_2 (2011 $/MWh)	Levelized Cost of Electricty (COE) Excluding CO_2 (2011 $/MWh)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Coal									
Scrubbed Coal New	2013	650	4	$3,167	$4.25	$35.97	8,800	**$122.78**	**$98.45**
IGCC	2013	600	4	$3,565	$6.87	$59.23	8,700	**$137.24**	**$113.17**
IGCC with carbon sequestration	2016	520	4	$5,348	$8.04	$69.30	10,700	**$159.20**	**---**
Nuclear									
Advanced Nuclear	2016	2,236	6	$5,335	$2.04	$88.75	N/A	**$122.51**	**$122.51**
Natural Gas									
Advanced Gas/Oil Combined Cycle (CC)	2012	400	3	$1,003	$3.11	$14.62	6,430	**$106.04**	**$96.53**
Advanced CC with carbon sequestration	2016	340	3	$2,060	$6.45	$30.25	7,525	**$144.73**	**---**

IGCC = Integrated Coal-Gasification Combined Cycle

Note: Information in columns (1) through (8) is based on U.S. Energy Information Administration (EIA), *Table 1. Updated Estimates of Power Plants and Operating Costs* , Release Date: November 2010. Results in columns (9) and (10) are based on this EIA information and AEP internal estimates.

Ohio Valley Electric Corporation
Forecasted Inter-Company Power Agreement (ICPA) Billable Cost Summary
Calendar Years 2011 - 2040

(All dollars in 2011 $000 except where indicated)

	Year														
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Power Production Cost															
Excluding CO_2	$631,114	$605,983	$617,141	$608,778	$597,395	$603,810	$589,464	$589,611	$576,098	$577,863	$568,206	$554,703	$555,728	$544,120	$541,864
Including CO_2	$631,114	$605,983	$617,141	$608,778	$597,395	$603,810	$589,464	$826,552	$794,534	$775,611	$758,160	$737,171	$731,004	$745,364	$766,670
Generation (GWh)	14,737	14,645	14,536	14,752	14,753	14,950	15,108	15,158	15,290	15,185	15,185	15,185	15,185	15,185	15,185

	Year															Total
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2011-2040
Power Production Cost																
Excluding CO_2	$530,713	$528,452	$516,170	$509,683	$505,302	$498,631	$496,214	$487,268	$476,432	$470,607	$464,209	$460,502	$457,885	$452,132	$440,887	$16,056,965
Including CO_2	$784,600	$801,473	$806,423	$815,385	$831,189	$821,065	$815,232	$802,906	$788,726	$779,592	$769,920	$762,974	$757,153	$748,229	$733,847	$22,207,468
Generation (GWh)	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	15,185	452,815

Total Levelized Power Production Cost ($/MWh)

Excluding CO_2: **$ 60.90 /MWh**

Including CO_2: **$ 84.23 /MWh**

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 1
CASE NO. U-20804 (2021 PSCR PLAN)

DATA REQUEST NO. 1-12 SC

Request

For each individual provider of coal to OVEC with contracts in force in 2021 or during the 5-year forecast period, please:

a. Identify, by year, the name of each coal fuel provider and the state from which the coal was supplied;

b. Provide the amount of coal received in tons, the heat content of the coal received in mmbtu/ton, and the total delivered cost of coal in dollars.

c. Identify if the coal was provided under a contract purchase, a spot market purchase, or another form of purchase. If another form is identified, please specify the purchase type used.

d. If the supply was provided under contract purchase for a period longer than one year, identify the contractual end date.

e. For any fuel supplies provided under a contract with minimum take, take-or-pay, liquidated damages, or other fixed amount or fixed price provisions, identify the component considered fixed (in tons or mmbtu), the price of that component (in dollars per ton or dollars per mmbtu), the component considered variable (in tons or mmbtu), and the price of the variable component (in dollars per ton or dollars per mmbtu).

Response

I&M objects to this request to the extent it seeks documents or information which is not relevant to the subject matter of this proceeding and which is not reasonably calculated to lead to the discovery of admissible evidence. In support of this objection, I&M states the subject matter of this docket is a review of I&M's power supply and fuel costs and not OVEC's. In addition, I&M personnel do not have operational responsibility for OVEC.

As to Objection
Counsel

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 1
CASE NO. U-20804 (2021 PSCR PLAN)

DATA REQUEST NO. 1-13 SC

Request

For any coal fuel contracts for OVEC with contracts in force in 2021 or during the 5-year forecast period, please:

a. Identify the contract, including the supplier, the date the contract was signed, and the term of the contract;

b. Provide a full, unredacted copy of any coal fuel contracts identified in (a), above.

Response

I&M objects to this request to the extent it seeks documents or information which is not relevant to the subject matter of this proceeding and which is not reasonably calculated to lead to the discovery of admissible evidence. In support of this objection, I&M states the subject matter of this docket is a review of I&M's power supply and fuel costs and not OVEC's. In addition, I&M personnel do not have operational responsibility in OVEC.

As to Objection
Counsel

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 1
CASE NO. U-20804 (2021 PSCR PLAN)

DATA REQUEST NO. 1-21 SC

Request

Identify the specific capital investments that the Company or OVEC anticipates would be needed for each of the OVEC Units to be capable of complying with environmental regulations through 2025. For each such investment:

a. Describe the anticipated project and its timeline, including current construction status;

b. Identify the existing or anticipated regulation(s) that such investment would be intended to achieve compliance with.

c. Provide any available estimate of the following parameters of such project, identifying the year's dollars in which costs are stated: i. In-service date,

ii. Required outage period for installation and interconnection,
iii. projected capital cost,
iv. fixed O&M cost,
v. variable O&M cost,
vi. effect on unit heat rate,
vii. effect on unit availability.

Response

The Company is not the operator of the OVEC units and does not have this information.

Preparer
Vaughan

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 2
CASE NO. U-20804 (2021 PSCR PLAN)

DATA REQUEST NO. 2-6 SC

Request

For each of the following, state whether or not I&M has access to, possession of, and/or the ability to request and receive the specified data or information for the OVEC plants for 2021 or during the 5-year forecast period.

a. The full, unredacted version of all fuel contracts in force in 2021 or during the 5-year forecast period.

b. The names of each coal fuel provider, the state from which the coal was supplied.

c. The amount of coal received in tons, the hear content of the coal received in mmbtu/ton, and the total delivered cost of coal in dollars.

d. The type of contract associated with each coal purchase (contract, sport purchase, or other).

e. The contractual end date of each coal supply contract.

f. For any fuel supplies provided under a contract with a minimum take, take-or-pay, liquidated damages, or other fixed amount or fixed price provision, identify the component considered fixed (in tons or mmbtu) the price of that component (in dollars per ton or dollars per mmbtu), the component considered variable (in tons or mmbtu), and the price of the variable component (in dollars per ton or dolars per mmbtu).

g. The forecasted Fixed O&M costs for the OVEC units.

h. The forecasted Variable O&M costs for the OVE units.

i. The forecasted Fuel costs for the OVEC units.

j. Projects planned to allow OVECs units to comply with environmental regulations through 2025, including:

  i. Planned capital investments.
  ii. Project timeline and construction status.
  iii. Regulations each investment is intended to comply with.
  iv. Impact of planned upgrades on future operational costs and characteristics.

k. Projects planned to allow OVECs units to comply with environmental regulations through 2025.

l. The minutes of any or all meetings of the OVEC Board of Directors since January 1, 2018.

m. The minutes of any or all meetings of the IKEC Board of Directors since January 1, 2018.

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 2
CASE NO. U-20804 (2021 PSCR PLAN)

Response

I&M objects to this request to the extent it seeks documents or information which is not relevant to the subject matter of this proceeding and which is not reasonably calculated to lead to the discovery of admissible evidence. In support of this objection, I&M states the subject matter of this docket is a review of I&M's power supply and fuel costs and not OVEC's. In addition, I&M personnel do not have operational responsibility for OVEC.

As to objection
Counsel

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 2
CASE NO. U-20804 (2021 PSCR PLAN)

DATA REQUEST NO. 2-7 SC

Request

For each of the following, state whether or not the Company has reviewed the specified data or information for the OVEC plants.

a. The full, unredacted version of all fuel contracts in force in 2021 or during the 5-year forecast period.

b. The names of each coal fuel provider, the state from which the coal was supplied.

c. The amount of coal received in tons, the hear content of the coal received in mmbtu/ton, and the total delivered cost of coal in dollars.

d. The type of contract associated with each coal purchase (contract, sport purchase, or other).

e. The contractual end date of each coal supply contract.

f. For any fuel supplies provided under a contract with a minimum take, take-or-pay, liquidated damages, or other fixed amount or fixed price provision, identify the component considered fixed (in tons or mmbtu) the price of that component (in dollars per ton or dollars per mmbtu), the component considered variable (in tons or mmbtu), and the price of the variable component (in dollars per ton or dolars per mmbtu).

g. The forecasted Fixed O&M costs for the OVEC units.

h. The forecasted Variable O&M costs for the OVE units.

i. The forecasted Fuel costs for the OVEC units.

j. Projects planned to allow OVECs units to comply with environmental regulations through 2025, including:

    i. Planned capital investments.
    ii. Project timeline and construction status.
    iii. Regulations each investment is intended to comply with.
    iv. Impact of planned upgrades on future operational costs and characteristics.

k. Projects planned to allow OVECs units to comply with environmental regulations through 2025.

l. The minutes from each meeting of the OVEC Board of Directors since January 1, 2018.

m. The minutes from each meeting of the IKEC Board of Directors since January 1, 2018.

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 2
CASE NO. U-20804 (2021 PSCR PLAN)

Response

I&M objects to this request to the extent it seeks documents or information which is not relevant to the subject matter of this proceeding and which is not reasonably calculated to lead to the discovery of admissible evidence. In support of this objection, I&M states the subject matter of this docket is a review of I&M's power supply and fuel costs and not OVEC's. In addition, I&M personnel do not have operational responsibility for OVEC.

In addition, I&M states it does not have the forecasted OVEC unit information for subparts g, h and i.

As to objection
Counsel

SC-9C

CONFIDENTIAL EXHIBIT

PJM Cost of New Entry

Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date

PREPARED FOR

PJM Interconnection, L.L.C.

PREPARED BY

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April 19, 2018

THE Brattle GROUP

This report was prepared for PJM Interconnection, L.L.C. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or Sargent & Lundy, or their clients.

The authors would like to thank PJM staff for their cooperation and responsiveness to our many questions and requests. We would also like to thank the PJM Independent Market Monitor for helpful discussions.

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Executive Summary

PJM Interconnection, L.L.C (PJM) retained The Brattle Group (Brattle) and Sargent & Lundy (S&L) to review key elements of the Reliability Pricing Model (RPM), as required periodically under PJM's tariff.[1] This report presents our estimates of the Cost of New Entry (CONE). A separate, concurrently-released report presents our review of PJM's methodology for estimating the net energy and ancillary service (E&AS) revenue offset and the Variable Resource Requirement (VRR) curve.[2]

CONE represents the total annual net revenue (net of variable operating costs) that a new generation resource would need to recover its capital investment and fixed costs, given reasonable expectations about future cost recovery over its economic life. CONE is the starting point for estimating the Net Cost of New Entry (Net CONE). Net CONE represents the first-year revenues that a new resource would need to earn in the capacity market, after netting out E&AS margins from CONE. CONE and Net CONE of the simple-cycle combustion turbine (CT) reference resource are used to set the prices on PJM's VRR curve.[3] CT and combined-cycle (CC) Net CONE are used to establish offer price thresholds below which new gas-fired generation offers are reviewed under the Minimum Offer Price Rule (MOPR).[4]

We estimate CONE for CTs and CCs in each of the four CONE Areas specified in the PJM Tariff, with an assumed online date of June 1, 2022.[5] Our estimates are based on complete plant designs reflecting the locations, technology choices, and plant configurations that developers are likely to choose, as indicated by actual projects and current environmental requirements. For both the CT and CC plants, we specify GE 7HA turbines—one for the CT, and two for the CC in combination with a single heat recovery steam generator and steam turbine ("2×1 configuration"). Most plants have selective catalytic reduction (SCR), except CTs in the Rest of RTO Area. Most plants also have dual-fuel capability, except CCs in the SWMAAC Area, which obtain firm gas transportation service instead.

For each plant type and location, we conduct a comprehensive, bottom-up analysis of the capital costs to build the plant: the engineering, procurement, and construction (EPC) costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project

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1 PJM Interconnection, L.L.C. (2017). PJM Open Access Transmission Tariff. Effective October 1, 2017, ("PJM 2017 OATT"), accessed 2/7/2018 from http://www.pjm.com/directory/merged-tariffs/oatt.pdf, Section 5.10 a.

2 "Fourth Quadrennial Review of PJM's Variable Resource Requirement Curve" or "2018 VRR Report".

3 See 2018 VRR Report for how CONE and Net CONE values are used to set the VRR curve.

4 PJM 2017 OATT, Section 5.14 h.

5 Previous CONE studies had five CONE Areas, but the Dominion CONE Area was removed in recent tariff changes and is now included in the Rest of RTO CONE Area.

development, financing fees, gas and electric interconnection costs, and inventories. We separately estimate annual fixed operation and maintenance (O&M) costs, including labor, materials, property taxes, and insurance.

Finally, we translate the estimated costs into the annualized average net revenues the resource owner would have to earn over an assumed 20-year economic life to achieve its required return on and return of capital. We assume an after-tax weighted-average cost of capital (ATWACC) of 7.5% for a merchant generation investment, which we estimated based on various reference points. An ATWACC of 7.5% is equivalent to a return on equity of 12.8%, a 6.5% cost of debt, and a 65/35 debt-to-equity capital structure with an effective combined state and federal tax rate of 29.25%. For some states with higher state income tax rates of 10%, the ATWACC is 7.4%. We adopt the "level-nominal" approach for calculating the first-year annualized costs of the plants.

Table ES-1 below shows the updated 2022/23 CONE estimates and how the values compare to the CONE parameters used in the upcoming auctions for the 2021/22 delivery year, escalated forward one year to 2022/23. As indicated, costs have decreased sharply by 22–28% for CTs and 40–41% for CCs.

Table ES-1: Updated 2022/2023 CONE Values

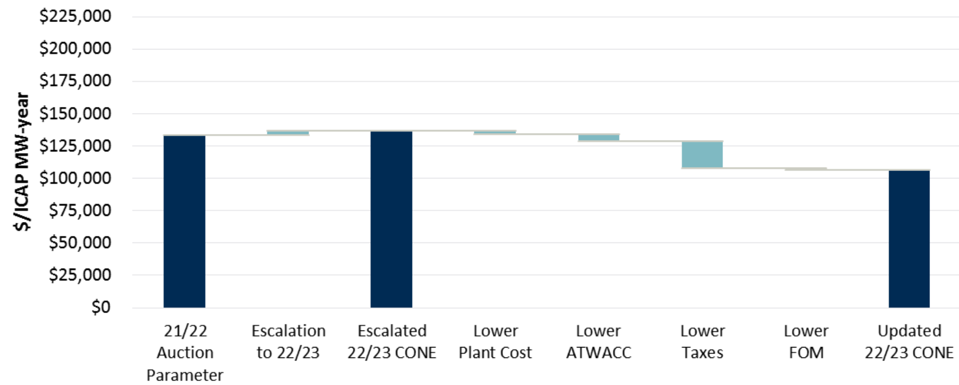
	Simple Cycle ($/ICAP MW-year)				Combined Cycle ($/ICAP MW-year)			
	EMAAC	SWMAAC	Rest of RTO	WMAAC	EMAAC	SWMAAC	Rest of RTO	WMAAC
2021/22 Auction Parameter	$133,144	$140,953	$133,016	$134,124	$186,807	$193,562	$178,958	$185,418
...Escalated to 2022/23	$136,900	$144,900	$136,700	$137,900	$192,000	$199,000	$184,000	$190,600
Updated 2022/23 CONE	**$106,400**	**$108,400**	**$98,200**	**$103,800**	**$116,000**	**$120,200**	**$109,800**	**$111,800**
Difference from Prior CONE	-22%	-25%	-28%	-25%	-40%	-40%	-40%	-41%

Sources and notes:
All monetary values are presented in nominal dollars.
2021/22 auction parameter values based on Minimum Offer Price Rule (MOPR) Floor Offer Prices for 2021/22 BRA.
PJM 2021/22 parameters escalated to 2022/23 by 2.8%, based on S&L analysis of escalation rates for materials, turbine, and labor costs.
CONE includes major maintenance costs in variable O&M costs. Alternative values with major maintenance costs in fixed O&M costs are presented in Appendix C.

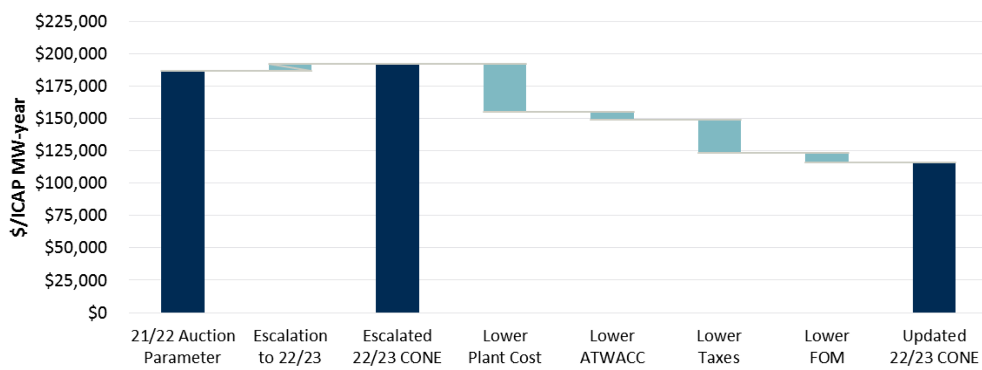
The drivers of these decreases are shown in Figure ES-1 and explained below.

Figure ES-1: Drivers of Lower CT and CC 2022/2023 CONE Estimates (EMAAC)

(a) Simple Cycle Combustion Turbine (CT)



(b) Combined Cycle (CC)



Notes:
"FOM" stands for fixed O&M costs.
CONE includes major maintenance in variable O&M costs.

Three factors drive most of this decrease in CONE:

- **Economies of scale on larger combustion turbines.** Selection of GE 7HA.02 turbines instead of the 7FA.05 turbines used in the 2014 PJM CONE study reflects a recent trend in actual project developments and future orders toward larger turbines. The GE H-class turbines are sized at 320 MW per turbine compared to 190 MW for F-class turbines in 2014; the capacity of a 2×1 CC plant nearly doubles from 650 to 1,140 MW.[6] This lowers both construction labor and equipment costs on a per-kW basis. As a result, the current overnight capital costs for a CT are only $799/kW to $898/kW (depending on location), 2–10% lower than the 2014 estimates of $890/kW to $927/kW escalated forward to 2022.[7]

[6] The max summer capacity is based on the estimated values for the Rest of RTO CONE Area.

[7] We compare the current capital cost estimates to those filed by PJM in the 2014 CONE update. We escalated the 2018 capital costs to 2022 by first applying the location-specific escalation rates PJM used for the 2019/20, 2020/21, and 2021/22 CONE updates for the first three years and then escalating the costs an additional year by 2.8%/year based on cost trends in labor, equipment, and materials inputs.

CC capital costs range from $772/kW to $873/kW, about 25% lower than the 2014 estimates of $1,054/kW to $1,127/kW escalated to 2022.

- **Reduced federal taxes.** The tax law passed in December 2017 reduced the corporate tax rate to 21% and temporarily increased bonus depreciation to 100%, although it eliminated the state income tax deduction.[8] These changes decrease the CT CONE by about $21,000/MW-year (17% lower) and the CC CONE by about $25,000/MW-year (18% lower), before accounting for the higher cost of capital due to the lower tax rate.
- **Lower cost of capital.** We estimate an ATWACC of 7.5% for merchant generation based on current and projected capital market conditions and the change in the corporate tax rate. Compared to an ATWACC of 8.0% in the 2014 study, the lower ATWACC reduces the annual CONE value by 3.7% for CTs and 3.8% CCs.

The updated CONE values shown above assume that major maintenance costs are treated as variable O&M costs, as in past CONE studies. We separately report in Appendix C alternative CONE values to reflect changes in the PJM cost guidelines since the 2014 CONE Study in which major maintenance costs are classified as fixed O&M costs instead of variable O&M costs.[9] Classifying these costs as fixed instead of variable increases CONE by $19,000/MW-year for CTs (a 19% increase) and $10,000/MW-year for CCs (a 9% increase). However, removing these costs from variable O&M increases Net E&AS revenues and offsets the increased CONE value in the calculation of Net CONE.

Table ES-2 shows additional details on the CONE estimates for CT plants in each CONE Area. The higher CONE in SWMAAC relative to other areas reflects higher property taxes in Maryland that are based on all property, including equipment, not just land and buildings. EMAAC's relatively high costs reflect higher labor costs there. The Rest of RTO Area has the lowest CONE value due to lower labor costs and the assumption that an SCR is not needed to reduce NOx emissions in attainment areas.

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8 "Bonus depreciation" refers to the allowance by tax law of highly accelerated tax depreciation immediately upon in-service of a depreciable asset. In recent years, bonus depreciation has been enabled by legislation in varying percentages of the overall tax basis in an asset, with the remainder deducted over the asset life as otherwise allowed. Per the 2017 tax law, bonus depreciation is allowed for companies not classified as public utilities up to 100% of tax basis.

9 An ongoing stakeholder process within the Markets Implementation Committee is addressing whether the PJM cost guidelines should be modified to again allow major maintenance costs to be included in variable O&M costs.

Table ES-2: Estimated CT CONE for 2022/2023

		Simple Cycle			
		EMAAC	SWMAAC	Rest of RTO	WMAAC
Net Summer ICAP	*MW*	352	355	321	344
Overnight Costs	*$/kW*	$898	$836	$799	$886
Effective Charge Rate	*%*	10.1%	10.1%	10.0%	10.0%
Plant Costs	*$/MW-yr*	$90,300	$84,300	$80,300	$88,900
Fixed O&M	*$/MW-yr*	$16,100	$24,100	$17,900	$14,900
Levelized CONE	***$/MW-yr***	**$106,400**	**$108,400**	**$98,200**	**$103,800**
Levelized CONE	***$/MW-day***	**$292**	**$297**	**$269**	**$284**

Notes: CONE values expressed in 2022 dollars and Installed Capacity (ICAP) terms.

Table ES-3 shows the recommended CONE estimates for CC plants in each CONE Area. SWMAAC has the highest CONE estimate due to higher property taxes and the higher costs of firm gas transportation service compared to dual-fuel capabilities (which is specified in the other Areas). EMAAC has the next highest CONE estimate due to higher labor costs than the rest of PJM. WMAAC and Rest of RTO have the lowest CC CONE estimates due to the lower labor costs in those areas.

Table ES-3: Estimated CC CONE for 2022/2023

		Combined Cycle			
		EMAAC	SWMAAC	Rest of RTO	WMAAC
Net Summer ICAP	*MW*	1,152	1,160	1,138	1,126
Overnight Costs	*$/kW*	$873	$772	$815	$853
Effective Charge Rate	*%*	10.6%	10.6%	10.5%	10.5%
Plant Costs	*$/MW-yr*	$92,200	$81,800	$85,900	$89,900
Fixed O&M	*$/MW-yr*	$23,800	$38,400	$23,900	$21,900
Levelized CONE	***$/MW-yr***	**$116,000**	**$120,200**	**$109,800**	**$111,800**
Levelized CONE	***$/MW-day***	**$318**	**$329**	**$301**	**$306**

Notes: CONE values expressed in 2022 dollars and ICAP terms.

The updated CONE estimates for CCs have decreased significantly more than CTs over the prior estimates, leading to a CC premium of $8,000–11,800/MW-year compared to $46,000–54,000/MW-year in the 2020/21 Base Residual Auction (BRA) parameters. The most significant driver narrowing the difference between CT and CC CONE is economies of scale of the larger CC based on the 7HA. While the capacity of the CCs plants has almost *doubled* compared to that in the 2014 CONE Study, the cost of the gas turbines increased by 50%, and the cost of the steam section of the CC (including the heat recovery steam generator and steam turbine) increased by only 30%. CT plants share the same economies of scale on the combustion turbine itself, but not the greater economies of scale that CCs enjoy on their steam section or other plant costs.

Looking beyond the 2022/23 delivery year, we recommend that PJM update the above CONE estimates prior to each subsequent auction using its existing annual updating approach based on a composite of cost indices, but with slight adjustments to the weightings. Consistent with the updated capital cost estimates, we recommend that PJM weight the components in the CT composite index based on 20% labor, 55% materials (increased from 50%), and 25% turbine (decreased from 30%). We recommend that PJM weight the CC components based on 30% labor (increased from 25%), 50% materials (decreased from 60%), and 20% turbine (increased from 15%). PJM will need to account for bonus depreciation declining by 20% in subsequent years starting in 2023. Consequently, after PJM has escalated CONE by the composite cost index, we recommend that PJM apply an additional gross-up of 1.022 for CT and 1.025 for CCs each year to account for the declining tax advantages as bonus depreciation phases out.

DUKE ENERGY OHIO EXHIBIT ______

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates.	))	Case No. 17-32-EL-AIR
In the Matter of the Application of Duke Energy Ohio, Inc., for Tariff Approval.	))	Case No. 17-33-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods.	))	Case No. 17-34-EL-AAM
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Modify Rider PSR.	))	Case No. 17-872-EL-RDR
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Amend Rider PSR.	))	Case No. 17-873-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods.	))	Case No. 17-874-EL-AAM
In the Matter of the Application of Duke Energy Ohio, Inc., for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.	)))))	Case No. 17-1263-EL-SSO
In the Matter of the Application of Duke Energy Ohio, Inc., for Authority to Amend its Certified Supplier Tariff, P.U.C.O. No. 20.	)))	Case No. 17-1264-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Authority to Defer Vegetation Management Costs.	))	Case No. 17-1265-EL-AAM
In the Matter of the Application of Duke Energy Ohio, Inc., to Establish Minimum Reliability Performance Standards Pursuant to Chapter 4901:1-10, Ohio Administrative Code.	)))	Case No. 16-1602-EL-ESS

REVISED

PUBLIC VERSION

SUPPLEMENTAL TESTIMONY OF

JUDAH L. ROSE

ON BEHALF OF

DUKE ENERGY OHIO

July 10, 2018

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variation in generation supply costs, industry cycles and changes in FERC regulations. Greater reliance on natural gas will increase spot power price volatility, especially in situations where natural gas production and delivery infrastructure falls behind increased natural gas consumption.

Q. HOW DOES THE MARKET VOLATILITY COMPARE TO THE VOLATILITY OF THE OVEC CONTRACT COST?

A. It is five times higher.

I.3 POWER PLANT FORECASTS

Q. WHAT IS YOUR FORECAST OF CLIFTY CREEK AND KYGER CREEK DISPATCH?

A. Between 2018 and 2025, I forecast the average[11] plant utilization rates will be [BEGIN CONFIDENTIAL] [redacted] The increase reflects increasing natural gas and electrical energy prices, the impact of retirements, growing electricity demand and the lack of new coal power plant construction. While higher than historical, my updated [redacted] for Kyger Creek and Clifty Creek respectively, than my forecast in the Direct Testimony for 2018 to 2025. [12] [END CONFIDENTIAL]

[11] Average plants utilization rates include 2025 as partial year.
[12] 2025 is a full year for comparison

Q. WHAT IS YOUR FORECAST OF CLIFTY CREEK AND KYGER CREEK REVENUES?

A. Over the 2018 to 2025 period, in nominal dollars, I forecast the annual average total revenues for Clifty Creek and Kyger Creek will be [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q. WHAT ARE YOUR FORECASTS OF CLIFTY CREEK AND KYGER CREEK GROSS MARGINS?

A. Gross margin equals revenues less fuel and other short run variable costs. Over the 2018 to 2025, in nominal dollars, I forecast gross margins will have a present value of [BEGIN CONFIDENTIAL] [redacted] [END

[13] Duke Energy Ohio (DEO) owns 9% of the ICPA contract. In this annual average calculation, 2025 is considered as a full year.
[14] In average revenue rate calculation, 2025 is a full year. Revenues on average are higher than all-hours price because dispatch is high but not 100%.
[15] Partial year 2025.
[16] In gross margins average calculation, 2025 is a full year

CONFIDENTIAL] Revenues increase faster than costs and margins increase faster than revenues – *i.e.*, there is operating leverage.

Q. WHAT IS THE FORECAST OF OVEC DEMAND CHARGES?

A. OVEC demand charges are paid pursuant to the ICPA originally entered into in 1953. The demand charges are set in the same manner as cost recovery of a traditional rate base power plant. Duke Energy Ohio provided ICF the forecast of OVEC's projected demand charges.[17] Between 2018 and 2025[18], total demand charges average approximately [BEGIN CONFIDENTIAL] [redacted] As noted, this forecast [redacted] in my Direct Testimony. [END CONFIDENTIAL]

Q. HOW SHOULD SUNK COSTS BE TREATED?

A. Society's economic value[19] is maximized by maximizing the cash going forward net margins and treating previously incurred capital investment as sunk – *i.e.,* by not including sunk costs in the decision regarding the asset's utilization. My economic analysis excluding sunk costs concludes that OVEC should continue to operate its power plants. This is especially true when the hedge value of the contract and the improving price trend is considered.

Duke Energy Ohio is requesting recovery of all costs, including sunk costs, via Rider PSR. I note that this request may be appropriate in spite of the complexities of OVEC's situation, notably the plants are not owned by or rate

[17] Demand Charges are from OVEC "20yearbillable.xls" spreadsheet
[18] 2025 is a full year in the average demand charge calculation.
[19] Assuming efficient pricing.

based by Duke Energy Ohio but are rather subject to a long term power agreement under which Duke Energy Ohio has little control of OVEC. It is my understanding that the specific contract was undertaken long ago (though amended in 2004 and 2011) and well before deregulation of any power markets. The diversity of the players and regulatory frameworks and the regional scope of the situation does not lend itself to easily changing the contract or establishing a policy regarding the future of the plants (*e.g.,* unanimous decision making). This arrangement is consistent with this situation being a legacy of a former era in which the form was secondary to the intent which was to urgently support reliable production of enriched uranium in the early 1950s. While the form of the arrangement is contractual, it may have been the original intent to treat the Department of Defense similar to or better than other firm customers and treat the plants in a manner similar to jointly owned, rate base power plants – *i.e.,* similar to other power plants approved and included in the rate base. Evidence for this is that the payments are determined the same way traditionally regulated costs are determined. This argues for recovery of costs including sunk costs because they were prudently incurred.

Notwithstanding the above, I have not conducted a detailed history of the contract, the plant's regulation, and I defer to the expertise of the PUCO on how to treat the sunk costs with regard to rate recovery for the Company. I also acknowledge that this is a different, complex and unique situation. Finally, it is my understanding that most decisions and changes to the contract require unanimous consent. Accordingly, I also report the results based on the total demand charge including recovery of sunk capital.

Q. WHAT IS THE FORECAST OF CLIFTY CREEK AND KYGER CREEK NET MARGINS USING CASH GOING FORWARD COSTS?

A. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q. WHAT IS THE FORECAST OF CLIFTY CREEK AND KYGER CREEK NET MARGINS USING EIA'S UPDATED GAS PRICES?

A. Also in Exhibit 1, I present the net present value of pre-tax net margins on a cash going-forward basis using the DOE Energy Information Agency (EIA) Annual Energy Outlook (AEO) 2018 Reference Case gas price forecast.[21] [BEGIN CONFIDENTIAL] [redacted]

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[20] [BEGIN CONFIDENTIAL [redacted] [END CONFIDENTIAL]

[21] US EIA's "*Annual Energy Outlook 2018.*" This case assumes no national CO_2 regulations for all time periods.

[redacted] [END CONFIDENTIAL]

Q. DO THE NET MARGINS INCLUDE HEDGE VALUE?

A. No, the results shown do not include any hedge value even though the contracts costs are less volatile than relying on market. Adding hedge value would make the results more positive.

Q. HOW DOES THIS FORECAST COMPARE TO THE FORECAST IN THE DIRECT TESTIMONY?

A. In my Direct Testimony [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q. WHAT IS THE FORECAST OF CLIFTY CREEK AND KYGER CREEK NET MARGINS USING TOTAL DEMAND CHARGES?

A. I present results with and without considerations of sunk costs (*i.e.,* with demand charges excluding sunk costs and including sunk costs) in Exhibits 1 and 2. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

---

[22] Partial year 2025.

[BEGIN CONFIDENTIAL]

Exhibit 1

Duke Energy Ohio's Share of the OVEC Portfolio Net Margins (Present Value millions $)

Case	Sunk Costs Included	2018-May 2025
ICF Base Case	No	0
AEO 2018 Reference Case	No	15

Source: ICF projections with supplementary data from AEO 2018, FERC Form 1, and OVEC

Note: Present value calculated for Jan 1, 2018 to May 31, 2025 using a discount rate of [redacted]

Exhibit 2

Duke Energy Ohio's Share of the OVEC Portfolio Net Margins (Present Value millions $)

Case	Sunk Costs Included	2018-May 2025
Base Case	Yes	(77)
AEO 2018 Reference Case	Yes	(62)

Source: ICF projections with supplementary data from AEO 2018, FERC Form 1, and OVEC

Note: Present value calculated for Jan 1, 2018 to May 31, 2025 using a discount rate of [redacted]

[END CONFIDENTIAL]

Q. WHAT IS YOUR ASSESSMENT OF THE PLANT'S ANNUAL COST VOLATILITY?

A. Annual wholesale market price volatility is five times higher than volatility in the costs of Clifty Creek and Kyger Creek. I discussed above the volatility of market prices. [BEGIN CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL]

I.4 CONCLUSIONS

Q. WHAT ARE YOUR CONCLUSIONS?

A. The updated ICF Base Case value of net margins for OVEC between 2018 and 2025 is lower than in my Direct Testimony. This reflects lower gas and power prices with the impact mitigated in part by lower coal and non-fuel costs at the OVEC plants and retirements in the market including the effect of recent nuclear power plant retirements in and near Ohio.

My update to my 2018 to 2025 forecast concludes OVEC plants provide electricity on a going forward cost basis [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

My updated volatility estimates are nearly unchanged for both the market and the OVEC contract – *i.e.*, market is five times more volatile. Therefore, the lower volatility of OVEC contract is an advantage and the contract acts like a hedge. Adding any hedge value would make the plants positive or better than market on a cash going forward basis.

In the updated US EIA gas price case, net margins on a cash going forward basis are positive and very close to the ICF Base Case forecast in my Direct Testimony. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

This also supports and reinforces the conclusion that continued plant operation through 2025 is economic.

Accordingly, I conclude the plants should continue to operate.

[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

My current 2018-2025 forecasts do not include quantitatively three sets of regulatory developments that are favorable to the economics of Clifty Creek and Kyger Creek and that occurred since the filing of my Direct Testimony. First, it is now very likely that potential national CO_2 emission and other environmental regulations adverse to OVEC's plants will be significantly deferred beyond 2025 compared to national CO_2 controls starting in 2022 as per the Clean Power Plan (CPP). While my Direct Testimony assumed no national CO_2 regulations until after 2025, prospects are now even more remote. Second, PJM has been developing capacity and energy market reforms that would increase prices. While these reforms do not quantitatively affect my forecast, they qualitatively support the upward trend in prices that commenced in 2017 and is continuing. Third, PJM, FERC and others may pursue grid resiliency initiatives economically favoring units like Clifty and Kyger Creek because they have significant amounts of on-site fuel. I have not quantitatively accounted for this possibility in my analysis.

II. RECENT WHOLESALE POWER PRICING TRENDS

Q. WHAT WERE THE WHOLESALE PRICES FOR ENERGY FOR THE LAST 9 YEARS?

A. Exhibit 3 below provides wholesale electrical energy market prices for the period from 2009 to 2017.[23] Electrical energy prices are set node-by-node, but PJM reports load weighted zonal averages for demand nodes and hubs and simple averages for supply nodes. Between 2012 and 2017, AEP Dayton Hub all-hours electrical energy prices averaged \$33.8/MWh in real 2016 dollars, and \$33.1/MWh in nominal dollars. Historically, Clifty Creek and Kyger Creek nodal prices averaged 5.5 percent lower compared to AEP Dayton Hub's all-hours prices. In nominal dollars, the range of AEP Dayton Hub's prices was from \$44.1/MWh in 2014 to \$27.8/MWh in 2016 or \$16.2/MWh – *i.e.,* the lowest prices were in 2016. As noted, 2015/2016 winter weather was among the warmest on record and electrical energy prices and natural gas prices were very low.

[23] Historical energy pricing data come from publicly available sources including Platts, Ventyx, SNL Financial and ICE data compilations. Capacity pricing data is publicly available through the PJM BRA results, available on the PJM website and through various news sources.

**IN THE UNITED STATES BANKRUPTCY COURT
FOR THE NORTHERN DISTRICT OF OHIO
AKRON DIVISION**

In re:	)	Chapter 11
	)	
FIRSTENERGY SOLUTIONS CORP., *et al.*,[1]	)	Case No. 18-50757 (Request for Joint Administration Pending)
	)	
Debtors.	)	Hon. Judge Alan M. Koschik

EXPERT DECLARATION OF JUDAH L. ROSE IN SUPPORT OF: (1) THE MOTION OF FIRSTENERGY SOLUTIONS CORP. AND FIRSTENERGY GENERATION, LLC FOR PRELIMINARY AND PERMANENT INJUNCTION AND *EX PARTE* TEMPORARY RESTRAINING ORDER AGAINST THE FEDERAL ENERGY REGULATORY COMMISSION; (2) THE MOTION FOR ENTRY OF AN ORDER AUTHORIZING FIRSTENERGY SOLUTIONS CORP. AND FIRSTENERGY GENERATION, LLC TO REJECT CERTAIN ENERGY CONTRACTS; AND (3) THE MOTION FOR ENTRY OF AN ORDER AUTHORIZING FIRSTENERGY SOLUTIONS CORP. AND FIRSTENERGY GENERATION, LLC TO REJECT A CERTAIN MULTI-PARTY INTERCOMPANY POWER PURCHASE AGREEMENT WITH THE OHIO VALLEY ELECTRIC CORPORATION

I, Judah L. Rose, hereby declare under penalty of perjury:

1. My name is Judah L. Rose. I am an Executive Director of ICF International ("ICF"). My business address is 9300 Lee Highway, Fairfax, Virginia 22031.

2. I respectfully submit this expert Declaration in support of (i) *the Motion of FirstEnergy Solutions Corp.* ("FES") *and FirstEnergy Generation, LLC* ("FG") *for Permanent and Preliminary Injunction and Ex Parte Temporary Restraining Order Against the Federal Energy Regulatory Commission* ("FERC") in the above captioned adversary proceeding; (ii) *the Motion of FES and FG for Entry of an Order Authorizing FES and FG to Reject Certain Energy*

[1] The Debtors in these chapter 11 cases, along with the last four digits of each Debtor's federal tax identification number, are: FE Aircraft Leasing Corp. (9245), case no. 18-50759; FirstEnergy Generation, LLC (0561), case no. 18-50762; FirstEnergy Generation Mansfield Unit 1 Corp. (5914), case no. 18-50763; FirstEnergy Nuclear Generation, LLC (6394), case no. 18-50760; FirstEnergy Nuclear Operating Company (1483), case no. 18-50761; FirstEnergy Solutions Corp. (0186); and Norton Energy Storage L.L.C. (6928), case no. 18-50764. The Debtors' address is: 341 White Pond Dr., Akron, OH 44320.

Contracts; and (iii) *the Motion of FES and FG for Entry of an Order Authorizing FES and FG to Reject a Certain Multi-Party Intercompany Power Purchase Agreement with the Ohio Valley Electric Corporation.*

3. I received a degree in economics from the Massachusetts Institute of Technology and a Master's Degree in Public Policy from the John F. Kennedy School of Government at Harvard University. I have worked at ICF for over 35 years. I am an Executive Director and Chair of ICF's Energy Advisory and Solutions practice. I have also served as a member of the Board of Directors of ICF International and am one of three people among ICF's roster of approximately 5,000 professionals to have received ICF's honorary title of Distinguished Consultant.

4. ICF works with a variety of clients across the private and public energy sectors including governmental entities (such as the Federal Energy Regulatory Commission, the U.S. Department of Energy, state regulators and energy agencies), and private companies such as American Electric Power, Allegheny, Arizona Power Service, Dominion Power, Delmarva Power & Light, Dominion, Duke Energy, FirstEnergy, Entergy, Exelon, Florida Power & Light, Long Island Power Authority, National Grid, Northeast Utilities, Southern California Edison, Sempra, PacifiCorp, Pacific Gas and Electric, Public Service Electric and Gas, PEPCO, Public Service of New Mexico, Nevada Power, and Tucson Electric. ICF also works with Regional Transmission Organizations and similar organizations. I have personally consulted with or testified as an energy industry expert on behalf of most of the listed clients.

5. I have extensive experience in assessing wholesale electric power market design and regulation. I also have extensive experience forecasting wholesale electricity prices, power plant operations and revenues, transmission flows, and fuel prices (e.g., coal, natural gas,

renewable energy). I also have extensive experience in valuing individual power plants in the context of projected market conditions.

6. ICF was retained by counsel to the Debtors in April of 2017 to calculate the losses to the Debtors associated with: (a) eight burdensome executory power purchase agreements (the "PPAs") under which FES buys energy, capacity, and renewable energy credits ("RECs"); and (b) a certain multi-party intercompany power purchase agreement with the Ohio Valley Electric Corporation (as amended and restated, the "OVEC ICPA" and together with the PPAs, the "Executory PPAs"). Specifically, ICF was retained to determine the short and long-term costs of continued performance. ICF performed an initial analysis of the Executory PPAs in mid-2017, and then updated its work commencing in January 2018.

7. The background of the Executory PPAs, which expire between 2024 and 2040, is described in greater detail in the Declaration of Kevin T. Warvell. At the time ICF was retained, the Debtors had already identified these contracts as burdensome and unnecessary to their business, and had performed preliminary calculations. I, along with my colleague David Gerhardt, have reviewed documents made available to me by counsel, including the Executory PPAs, and numerous operational and financial reports from the Debtors, and performed other investigations to determine the facts and circumstances in this declaration. This declaration is based on my personal knowledge and a review of relevant documents and various calculations and data. I have used principles generally accepted in the energy markets for estimating the costs to the Debtors of the Executory PPAs and forecasting the future value of energy and renewable energy credits. If called as a witness, I could and would testify competently thereto.

8. Market circumstances have resulted in an extended period of commodity prices and REC prices much below those prices found in the Executory PPAs. The main drivers to the collapse in prices include:

- Lower natural gas prices due to continued improvements in natural gas fracking;
- Excess generating capacity due in part to lower than expected load growth;
- Lower cost of construction for renewable technologies, and/or improved performance (*e.g.*, higher capacity factors); and
- Surplus of RECs.

Taken together, these market forces have decreased wholesale electricity prices, and prices of RECs, to levels not envisioned at the time the Executory PPAs were signed. Such market forces have prevailed for the last three to four years and are now expected to continue for the next few years, at a minimum.

9. ICF has individually assessed the Executory PPAs to determine the estimated losses to FES and FG of performing such contracts over their lifetime. These calculations took into account the length of the contracts, the contract price, the expected volume using historical data, and the expected revenue streams. With respect to the OVEC ICPA, ICF took into account both fixed and variable costs such as fuel, coal, variable and fixed operations and management costs, capital expenditures, financing costs and emissions costs associated with that agreement. ICF's calculations used an internal production cost model which simulated the specific power markets in which the Ohio Valley Electric Corporation ("OVEC") and the other contract counterparties operate.

10. To determine the future losses, ICF compared the cost of the contracts over their lifetime with the forecasted future power prices in the market. In forecasting these rates, ICF looked separately at energy price, capacity price, and REC price. For the years 2018-2020, ICF was able to use the actual PJM auction price for capacity prices.[2] For energy prices and for capacity prices in later years, ICF used both a long-term 30-year pricing model and an annual model maintained in the ordinary course of business by ICF specific to the PJM marketplace which takes into account the individual players in that marketplace.

11. The assumptions underlying all calculations in the model are the results of external inputs such as OVEC production cost projections and NYMEX futures, as well as internal inputs which reflect the views of ICF's nationally recognized power practice group, which includes decorated experts in natural gas, coal, renewable energy, power modeling and energy markets. The inputs drawn from ICF's data and model are used by ICF generally (as then currently maintained) in all of its advisory, consulting and expert testimony work related to the future performance of the PJM market.

12. Based on the above-described analysis, I concluded that the estimated cost of maintaining the Executory PPAs to the estate would be $765 million on an undiscounted basis from April 1, 2018 to December 31, 2040. On a net present value ("NPV") basis over this same time period, and using a 7% discount rate, the estimated cost to the estate would be $475 million.

[2] "PJM" is PJM Interconnection, LLC. FES and FG conduct all of their business operations within the regional transmission organizations overseen by PJM, which is a regional transmission organization that covers 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. PJM coordinates, controls, and monitors multi-state electricity grids, and controls generation and transmission operations 24 hours a day, providing instructions to producers to ensure that the electric grid performs as desired.

In the near term (i.e., 2019-2023), the cost to the estate would be approximately $58 million per year.

13. Based on my review of the Warvell Declaration and diligence respecting FES generally, the capacity, power and RECs purchased under the Executory PPAs are unnecessary to FES's business, and the rejection of such agreements will not adversely impact FES's compliance with any other capacity, generation or retail obligations or the price or availability of power within PJM.

14. The estimated costs reflect an expected or base case. This case is based on available information about market and regulatory conditions. I have also examined sensitivity cases and all cases show high estimated damages. In the event of new information becoming available, I may update or refine these estimates.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

DATED:

Respectfully submitted,

Judah L. Rose

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's affirms OVEC at Ba1, changes outlook to stable from negative

11 Dec 2018

Approximately $1.4 billion of debt outstanding

New York, December 11, 2018 -- Moody's Investors Service (Moody's) affirmed the senior unsecured ratings of the Ohio Valley Electric Corporation (OVEC) at Ba1 and revised the outlook to stable from negative.

RATINGS RATIONALE

"The stable outlook recognizes the steps taken by OVEC management to bridge the approximate 5% shortfall in its revenue stream caused by the bankruptcy of one of its sponsors, FirstEnergy Solutions Corp. (FES)", said Laura Schumacher, Senior Credit Officer. These steps have included the funding of a debt reserve and the retention of earnings that can be used to offset future payment shortfalls. The affirmation of OVEC's Ba1 rating also considers the otherwise strong cost recovery provisions of the long term Inter-Company Power Agreement (ICPA) from which OVEC's revenues are derived, and acknowledges the solid overall credit quality of the remainder of the sponsor group.

In March 2018, FES filed for Chapter 11 bankruptcy protection, sought to reject the ICPA, and stopped paying its approximately 5% share of OVEC's costs. In July 2018, the bankruptcy court granted FES's motion to reject the contract based on a "business judgment" rather than a "public interest" standard. OVEC is currently challenging the bankruptcy court's approval of FES' rejection of the ICPA, as well as the court's decision to bar the Federal Energy Regulatory Commission (FERC) from the process. OVEC's challenges have been accepted for review by the United States Court of appeals for the Sixth Circuit. In the meantime, OVEC has filed a rejection damages claim of approximately $540 million against FES. Any damage awards could be used to offset future FES obligations, including debt repayment.

Following rejection of the ICPA, the FES share of energy and capacity has been allocated to the other sponsors, who have been paying their share of OVEC's variable costs; however, no one has "stepped-up" for FES' share of OVEC's fixed cost obligations. We estimate FES' share of OVEC's fixed costs to be approximately $17 million per year. In sensitivity testing, taking into account FES' share of energy and capacity revenues that are being paid, we estimate the shortfall could be reduced to about $10-$13 million per year; however these revenues are currently being allocated to the non-defaulting sponsors. As such, OVEC is currently bearing the entire cost of the shortfall, illustrating the exposure created by the lack of step-up provision in the current ICPA.

The shortfall created by the FES default is relatively modest, and as the default was widely anticipated, OVEC management was able to take steps to mitigate its impact. These steps have included funding a debt reserve at a rate of about $30 million per year (current balance is about $60 million), and the retention of the return on equity portion of its rates (approximately $2.5 million per year) as a cushion. This equity cushion would be sufficient to cover future FES shortfalls in the event the current FES shortfall is covered by short-term borrowing.

To date, there have been no draws from the debt reserve, and as of September 30, 2018, OVEC had $60 million of unrestricted cash on hand. In addition to the debt reserve, OVEC's long-term investments include about $70 million received as part of a prior settlement with the Department of Energy (DOE) that could be utilized to cover future shortfalls. The DOE funds had been ear-marked as a source of funding for future postretirement benefits; however OVEC has the ability to include a postretirement benefits charge in the fixed costs billed to the sponsors. This additional liquidity provides sufficient near-term coverage for the FES shortfall, and we expect the sponsors will continue to work toward implementing longer term, credit enhancing improvements to the ICPA after there is resolution of the issues surrounding the FES bankruptcy.

Rating outlook

The stable outlook recognizes the credit quality and outlooks of OVEC's non-defaulting sponsors, and the company's actions to address the limited financial impact of the current, ongoing, FES default. The outlook assumes payment shortfalls will continue to be addressed with excess operating cash, existing reserves, or via short-term borrowing. The outlook assumes OVEC will continue to collect reserve funds at the current rate at least until it has accumulated a full year of debt service (currently about 45% funded), and that it will extend the maturity of its revolving credit facility well in advance of its current November 2019 termination date.

Factors that could lead to an upgrade

Rating upgrades are unlikely over the near-term. Longer term, credit supportive changes to the ICPA; such as an inclusion of a step-up provision to mitigate the risk of future sponsor payment shortfalls or defaults; an improvement in the overall credit profile of the sponsor group; or stronger financial metrics, including a debt service coverage ratio above 1.6x, could put upward pressure on the rating.

Factors that could lead to a downgrade

An inability or unwillingness to continue collecting reserves or excess operating funds sufficient to cover payment shortfalls, an inability to extend OVEC's revolving credit facility beyond its November 2019 termination date in the early part of 2019, further declines in the credit quality of any sponsors, or a sponsor payment default that was not covered by existing reserves or through a swift replacement of the defaulting party, could lead to a downgrade.

Outlook Actions:

..Issuer: Ohio Valley Electric Corporation

....Outlook, Changed To Stable From Negative

Affirmations:

..Issuer: Ohio Valley Electric Corporation

....Senior Unsecured Bank Credit Facility, Affirmed Ba1

....Senior Unsecured Regular Bond/Debenture, Affirmed Ba1

..Issuer: Indiana Finance Authority

....Senior Unsecured Revenue Bonds, Affirmed Ba1

..Issuer: Ohio Air Quality Development Authority

....Senior Unsecured Revenue Bonds, Affirmed Ba1

OVEC owns and operates two coal-fired generating power plants, Kyger Creek in Ohio and Clifty Creek in Indiana, that have a combined capacity of approximately 2,400 MW. OVEC is sponsored by nine investor-owned regulated electric utilities, two independent generating companies (subsidiaries of a utility holding company) and two affiliates of generation and transmission cooperatives (collectively, the sponsors). The sponsors purchase OVEC's power at wholesale, cost based, rates. The ownership structure is governed by a long-term Inter-Company Power Agreement (ICPA) expiring in 2040.

The principal methodology used in these ratings was US Municipal Joint Action Agencies published in October 2016. Please see the Rating Methodologies page on www.moodys.com for a copy of this methodology.

REGULATORY DISCLOSURES

For ratings issued on a program, series or category/class of debt, this announcement provides certain regulatory disclosures in relation to each rating of a subsequently issued bond or note of the same series or category/class of debt or pursuant to a program for which the ratings are derived exclusively from existing ratings in accordance with Moody's rating practices. For ratings issued on a support provider, this announcement provides certain regulatory disclosures in relation to the credit rating action on the support provider and in relation to each particular credit rating action for securities that derive their credit ratings from the support provider's credit rating. For provisional ratings, this announcement provides certain regulatory disclosures in relation to the provisional rating assigned, and in relation to a definitive rating that may be assigned subsequent to the final issuance of the debt, in each case where the transaction structure and terms have not changed prior to the assignment of the definitive rating in a manner that would have affected the rating. For further information please see the ratings tab on the issuer/entity page for the respective issuer on www.moodys.com.

For any affected securities or rated entities receiving direct credit support from the primary entity(ies) of this credit rating action, and whose ratings may change as a result of this credit rating action, the associated regulatory disclosures will be those of the guarantor entity. Exceptions to this approach exist for the following disclosures, if applicable to jurisdiction: Ancillary Services, Disclosure to rated entity, Disclosure from rated entity.

Regulatory disclosures contained in this press release apply to the credit rating and, if applicable, the related rating outlook or rating review.

Please see www.moodys.com for any updates on changes to the lead rating analyst and to the Moody's legal entity that has issued the rating.

Please see the ratings tab on the issuer/entity page on www.moodys.com for additional regulatory disclosures for each credit rating.

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MOODY'S
INVESTORS SERVICE

SC-14C

CONFIDENTIAL EXHIBIT

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 1
CASE NO. U-20529 (2020 PSCR PLAN)

DATA REQUEST NO. 1-20 SC

Request

Explain the nature of the relationship that AEP Generation Services and other AEP entities play, if any, in procuring fuel on behalf of the OVEC Units.

Response

I&M objects to this request to the extent it seeks documents or information which is not relevant to the subject matter of this proceeding and which is not reasonably calculated to lead to the discovery of admissible evidence. In support of this objection, I&M states the subject matter of this docket is a review of I&M's power supply and fuel costs and not OVEC's. Without waiving this objection, I&M states

American Electric Power Service Corporation's (AEPSC's) Coal, Transportation, and Consumables Procurement ("Fuel Procurement") group provides coal procurement, consumables procurement and transportation procurement services to OVEC-IKEC. The Fuel Procurement group provides these services with the objective of obtaining an adequate supply of coal and consumables of sufficient quality from reliable suppliers at the lowest reasonable cost. OVEC-IKEC provides the projections of its coal and consumables requirements. AEPSC's Fuel Procurement group recommends procurement and transportation alternatives, which best meet the requirements and prepares the contracts and purchase orders to effect the desired transactions. The purchase of coal, consumables and transportation services are authorized by the appropriate OVEC-IKEC management.

As to Objection
Counsel

Preparer
Dial

OHIO VALLEY ELECTRIC CORPORATION
Minutes of Special Meeting of the
Board of Directors held December 1, 2015

A Special Meeting of the Board of Directors of **OHIO VALLEY ELECTRIC CORPORATION** (OVEC) was called to order by Mr. Mark C. McCullough at 1 Riverside Plaza, Columbus, Ohio, on Tuesday, December 1, 2015, at 10:00 a.m., pursuant to notice duly given. On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that in accordance with Article IV, Section 3 of the Code of Regulations of this Corporation, Mr. Mark C. McCullough be elected Chairman of this Meeting on December 1, 2015, in the absence of the President of this Corporation.

Mr. McCullough acted as Chairman of the meeting, and John D. Brodt, Chief Financial Officer, Secretary and Treasurer of the Corporation, acted as Secretary of the Meeting.

Mr. Brodt reported that the following Directors were present for the meeting:

Nicholas K. Akins (Phone)
Thomas Alban
Eric D. Baker (Phone)
Wayne D. Games
James R. Haney
Lana L. Hillebrand
Mark C. McCullough
Mark E. Miller
Donald A. Moul
Steven K. Nelson
Patrick W. O'Loughlin
Paul W. Thompson
John A. Verderame

Mr. Brodt reported that the Minutes of the Special Meeting of the Board of Directors of this Corporation, held on December 5, 2014, have been sent to each of the Directors. He asked that, if there were no corrections, such minutes be approved in the form in which they were circulated. On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the Minutes of the Special Meeting of the Board of Directors of this Corporation, held on December 5, 2014, are approved.

At the request of Mr. McCullough, Mr. Justin Cooper reported on the 2013 – 2016 LEAN Cost Structure cost profile. Mr. Cooper reviewed the results of the 2015 continuous improvements (LEAN) reductions and the operating, maintenance, and capital cost benchmarking budgets. Mr. Cooper reported that OVEC's operating, maintenance, and capital

CONFIDENTIAL INFORMATION REDACTED

cost profile was projected to [redacted] in 2016 compared with 2013. The energy cost [redacted] was expected to be [redacted].

Mr. McCullough asked Mr. Robert Osborne to give an update on the boiler floor refractory wastage issue and the replacement of floor tubes. The replacement of floor tubes has occurred on three boilers and four more will be replaced in 2016. Mr. Osborne discussed unit reliability and process health of the units.

Mr. McCullough asked Mr. Clifford Carnes and Ms. Annette Hope to report on operating activities for the Clifty Creek and Kyger Creek Plants, respectively. Mr. Carnes and Ms. Hope reviewed operating statistics and environmental and safety records for 2015 at each plant. Mr. Carnes and Ms. Hope reported on the sustainability of the LEAN process and the Open Book Leadership.

Mr. McCullough asked Mr. Copper to review the 2016 Construction Budget and the 2017-2020 Construction Budget Forecast. Mr. Cooper commented that the 2016 Construction Budget is a [redacted] compared with the [redacted] annual capital spending prior to implementation of OVEC's LEAN initiative. Mr. Cooper reported that the Construction Budget for 2016 indicates estimated total expenditures of [redacted], representing [redacted] and [redacted] On a motion duly made, seconded, and unanimously adopted, it was

RESOLVED, that the OVEC-IKEC Construction Budget for 2016, indicating estimated total expenditures of [redacted] which totals [redacted], is approved.

Mr. McCullough asked Mr. Brown to give an update on the OVEC and IKEC environmental compliance and to report on future environmental capital projects. Mr. Brown reported on Section 316(b) of the Clean Water Act, Coal Combustion Residual (CCR) Rule, and Effluent Limitations Guidelines compliance. Mr. Brown indicated the estimated cost of compliance may reach [redacted] during the [redacted] time frame. Mr. Brown requested authorization to complete entrainment studies at Kyger Creek and Clifty Creek Stations associated with the initial phase of 316(b) compliance, to perform Phase I engineering studies on the boiler slag complexes and FGD wastewater treatment plant systems, to perform additional analyses using results and findings of Kyger Creek Dry Fly Ash Conversion Project Phase I engineering study, to perform compliance activities and evaluations associated with the CCR Rule at the Kyger Creek and Clifty Creek Stations, and to perform engineering study and

CONFIDENTIAL INFORMATION REDACTED

capital work associated with modifications to the Kyger Creek Landfill stackout pad and leachate collections systems. On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the Company is authorized to proceed to perform the following environmental compliance activities:
>
> 1. Complete entrainment studies and other compliance activities at the Kyger Creek and Clifty Creek Stations associated with the initial phase of 316(b) compliance;
> 2. Perform Phase I engineering studies on the boiler slag complexes and FGD wastewater treatment plant systems at the Kyger Creek and Clifty Creek Stations to evaluate capital costs and options for compliance with the final version of the Steam Electric Effluent Limitations Guidelines (ELGs);
> 3. Perform additional analyses using results and findings of Kyger Creek Dry Fly Ash Conversion Project Phase I engineering study relative to the final ELGs;
> 4. Perform compliance activities and evaluations associated with the CCR Rule at the Kyger Creek and Clifty Creek Stations;
> 5. Perform engineering study and capital work associated with modifications to the Kyger Creek Landfill stackout pad and leachate collections systems to meet NPDES water quality based limits.
>
> The cost for the scope of work described above is forecasted to be a total of [redacted] for 2016 and 2017 inclusive. The results of these studies will be used to refine future environmental capital project costs prior to requesting the Boards' approval to complete each associated environmental capital project.

At the request of Mr. McCullough, Mr. Ken Tamms of the AEP Service Corporation reviewed the merchant plant analysis. A handout was provided to the Board, which indicated that [redacted]

At the request of Mr. McCullough, Mr. Charles West of the AEP Service Corporation discussed the coal and transportation contracts. A handout was provided to the Board, and a discussion followed describing the fuel supplies currently at each power plant as well as future commitments. Mr. West discussed [redacted] at both plants.

At the request of Mr. McCullough, Mr. Brodt provided information and discussed OVEC's year-to-date power costs estimated for 2015 and projections for 2016-2020. Mr. Brodt stated that based on current estimates OVEC expected to end 2015 with an average power cost of [redacted] and an available power use factor of [redacted]. Mr. Brodt stated that the

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projected average power cost for OVEC power, delivered under the terms of the Inter-Company Power Agreement, ranges from [redacted] in 2016 to [redacted] in 2020 using an estimated available power use factor of [redacted].

Mr. McCullough asked Mr. Scott Cunningham to report on the OVEC Operating Committee. Mr. Cunningham reported that the PJM pseudo-tie was scheduled to start in June 2016 and that the Operating Committee was studying PJM membership for OVEC.

At the request of Mr. McCullough, Mr. Brodt reviewed the 2015 Service Corporation general expenditures, which were expected to be approximately [redacted]. Mr. Brodt requested authorization for 2016 general expenditures for services from the AEP Service Corporation up to [redacted]. The primary general expenditures are expected to be in the areas of operation and maintenance, environmental activities, fuel procurement, and coal transportation. Mr. Brodt stated that the 2016 Budget is similar to the 2015 Budget except that the 2016 Budget request of [redacted] On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the officers of Ohio Valley Electric Corporation may request and obligate Ohio Valley Electric Corporation to pay for general services, exclusive of services for specific projects previously approved, under the Agreement among American Gas and Electric Service Corporation (now American Electric Power Service Corporation), Ohio Valley Electric Corporation, and Indiana-Kentucky Electric Corporation dated December 15, 1956, in an amount which, when added to amounts paid for general services by Indiana-Kentucky Electric Corporation, exclusive of services for specific projects previously approved, would aggregate a maximum of [redacted] for calendar year 2016.

At the request of Mr. McCullough, Mr. Brodt reported on the status of the Corporation's finances. Mr. Brodt distributed to all members present a copy of the Treasurer's Report that included the following statistics:

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OHIO VALLEY ELECTRIC CORPORATION (OVEC)
INDIANA-KENTUCKY ELECTRIC CORPORATION (IKEC)
Treasurer's Report
Boards of Directors' Meeting
December 1, 2015

	OVEC	IKEC	Consolidated
EQUITY			
Common Stock, 100,000 shares outstanding	$ 10,000,000	$ 3,400,000	$ 10,000,000
Retained Earnings	7,771,843	-	7,771,843
Total Equity at October 31, 2015	$ 17,771,843	$ 3,400,000	$ 17,771,843
(OVEC's ownership of IKEC's Capital Stock (17,000 shares) is eliminated in consolidation.)			
CASH AND INVESTMENTS			
Cash and Short-Term Investments	$ 11,534,278	$ -	$ 11,534,278
Reserve Account - Long Term Investments	78,666,596	-	78,666,596
Total Cash and Investments at October 31, 2015	$ 90,200,874	$ -	$ 90,200,874
DIVIDENDS			
Total 2015 Dividends	$ -	$ -	$ -
LONG-TERM DEBT			
2006 Senior Unsecured Notes, Series A, 5.80%, due February 15, 2026	$ 245,132,192	$ -	$ 245,132,192
2006 Senior Unsecured Notes, Series B, 6.40% due June 15, 2040	58,583,884	-	58,583,884
2007 Senior Unsecured Notes, Series AA, AB & AC, 5.90%, due February 15, 2026	172,329,341	-	172,329,341
2007 Senior Unsecured Notes, Series BA, BB & BC, 6.50% due June 15, 2040	44,425,396	-	44,425,396
2008 Senior Unsecured Notes, Series A, 5.92%, due February 15, 2026	35,718,051	-	35,718,051
2008 Senior Unsecured Notes, Series B & C, 6.71%, due February 15, 2026	141,148,369	-	141,148,369
2008 Senior Unsecured Notes, Series D & E, 6.91% due June 15, 2040	85,617,277	-	85,617,277
2013 Senior Unsecured Notes, Series A, Floating Rate, due February 15, 2018	100,000,000	-	100,000,000
2009 Tax Exempt Bonds, $100M Series A-D, Floating Rate, due February 1, 2026	100,000,000	-	100,000,000
2009 Tax Exempt Bonds, $100M Series E, 5.625%, due October 1, 2019	100,000,000	-	100,000,000
2010 Tax Exempt Bonds, $100M Series A & B, Floating Rate, due February 1, 2040	100,000,000	-	100,000,000
2012 Tax Exempt Bonds, $200M Series A, 5%, due June 1, 2039	200,000,000	-	200,000,000
2012 Tax Exempt Bonds, $100M Series B & C, Floating Rate, due June 1, 2040	100,000,000	-	100,000,000
Total Long-Term Debt Outstanding at October 31, 2015	$ 1,482,954,510	$ -	$ 1,482,954,510
SHORT-TERM DEBT			
Total Short-Term Debt Outstanding at October 31, 2015	$ 20,000,000	$ -	$ 20,000,000
EMPLOYEE BENEFIT PLAN ASSETS			
Pension Plan			$ [redacted]
Supplemental Pension & Savings Plan			[redacted]
Union Retiree Medical VEBA Trust			[redacted]
Retiree Medical VEBA Trust			[redacted]
Retiree Life Insurance VEBA Trust			[redacted]
401(h) - Retiree Medical			[redacted]
Total Benefit Plan Assets at October 31, 2015			$ [redacted]
PLANT DECOMMISSIONING & DEMOLITION (D&D) FUND			
Total D&D Assets at October 31, 2015	$ 18,155,970	$ 25,042,284	$ 43,198,254

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Mr. McCullough asked Mr. Brodt to discuss the OVEC 2015 financing plan. Mr. Brodt reported that OVEC's investment grade ratings of Baa3 (Moodys), BBB- (S&P), and BBB- (Fitch) had been affirmed with stable outlooks. Mr. Brodt stated that [redacted]

Mr. McCullough introduced Mr. Bob Bitter of Deloitte & Touche. Mr. Bitter reported that Deloitte & Touche just began its audit to certify the 2015 Financial Statements that would be finalized in April 2016.

Mr. McCullough asked Mr. Brown to discuss the Department of Energy (DOE) Arranged Power Agreement. Mr. Brown stated that DOE is working with a Sponsoring Company to provide power to DOE and end the Arranged Power Agreement with OVEC.

The Board moved to an Executive Session to hear the Human Resources Committee report.

There being no further business to come before the Board, the meeting was adjourned.

Secretary
OHIO VALLEY ELECTRIC CORPORATION

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OHIO VALLEY ELECTRIC CORPORATION
Minutes of Special Meeting of the
Board of Directors held December 1, 2016

A Special Meeting of the Board of Directors of **OHIO VALLEY ELECTRIC CORPORATION** (OVEC) was called to order by the President at 1 Riverside Plaza, Columbus, Ohio, on Thursday, December 1, 2016, at 10:00 a.m., pursuant to notice duly given.

Nicholas K. Akins, President of the Corporation, acted as Chairman of the meeting, and John D. Brodt, Chief Financial Officer, Secretary and Treasurer of the Corporation, acted as Secretary of the Meeting.

Mr. Brodt reported that the following Directors were present for the meeting:

Nicholas K. Akins	Mark E. Miller
Thomas Alban	Donald A. Moul
Eric D. Baker	Patrick W. O'Loughlin
Wayne D. Games	Julie Sloat (Phone)
Lana L. Hillebrand	Paul W. Thompson
Mark C. McCullough	John A. Verderame

Mr. Brodt reported that the Minutes of the Special Meeting of the Board of Directors of this Corporation, held on December 1, 2015, have been sent to each of the Directors. He asked that, if there were no corrections, such minutes be approved in the form in which they were circulated. On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the Minutes of the Special Meeting of the Board of Directors of this Corporation, held on December 1, 2015, are approved.

At the request of Mr. Akins, Mr. Brodt reviewed the 2016 Service Corporation general expenditures, which were expected to be approximately [redacted]. Mr. Brodt requested authorization for 2017 general expenditures for services from the AEP Service Corporation up to [redacted]. The primary general expenditures are expected to be in the areas of operation and maintenance, environmental activities, fuel procurement, and coal transportation. Mr. Brodt stated that the 2017 Budget is similar to the 2016 Budget except that the 2017 Budget request of [redacted]. The [redacted] in the 2017 Budget is related to [redacted]

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[redacted]. On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the officers of Ohio Valley Electric Corporation may request and obligate Ohio Valley Electric Corporation to pay for general services, exclusive of services for specific projects previously approved, under the Agreement among American Gas and Electric Service Corporation (now American Electric Power Service Corporation), Ohio Valley Electric Corporation, and Indiana-Kentucky Electric Corporation dated December 15, 1956, in an amount which, when added to amounts paid for general services by Indiana-Kentucky Electric Corporation, exclusive of services for specific projects previously approved, would aggregate a maximum of [redacted] for calendar year 2017.

Mr. Akins asked Mr. Mike Brown to give an update on the OVEC and IKEC environmental compliance status and to report on the work to develop cost estimates for future environmental capital projects. Mr. Brown reported on the status of developing cost estimates to comply with Effluent Limitations Guidelines, which include the construction of two closed loop boiler slag systems, two FGD wastewater ABMet and MBR treatment systems, and Kyger Creek dry fly ash conversion. In addition, Mr. Brown provided an update on cost estimates to comply with Section 316(b) and the Coal Combustion Residual (CCR) rule. OVEC's current environmental capital investment "best-case" cost estimate for these projects is [redacted], and the current "worst-case" cost estimate is [redacted]. An investment decision for additional funding for conceptual engineering and design will be required by year-end 2017.

At the request of Mr. Akins, Mr. Justin Cooper reported on the 2013 – 2017 LEAN Cost Structure cost profile. Mr. Cooper reviewed the results of the 2016 continuous improvements (LEAN) reductions and the operating, maintenance, and capital cost benchmarking budgets. Mr. Cooper reported that OVEC's operating, maintenance, and capital cost profile was projected to [redacted] in 2017 compared with 2013. The energy cost [redacted].

Mr. Akins asked Mr. Cooper to review the 2017 Construction Budget and the 2018-2021 Construction Budget Forecast. Mr. Cooper commented that the 2017 Construction Budget is a [redacted] with the original 2017 budget forecast with prioritization of economic benefit, risk, and fiscal impact. Mr. Akins requested that a list of future high-risk capital budget items be provided at the next meeting. Mr. Cooper reported that the Construction Budget for 2017 indicates estimated total expenditures of [redacted], representing

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[redacted] On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the OVEC-IKEC Construction Budget for 2017, indicating estimated total expenditures of [redacted]

Mr. Akins asked Mr. Osborne to report on operating activities for the Clifty Creek and Kyger Creek plants. Mr. Osborne reviewed the operating statistics and discussed how the Open Book Leadership scoreboard is being used to track key areas of concern. Mr. Osborne also reviewed the 2016 safety performance statistics and the need to focus on recognizing hazards.

At the request of Mr. Akins, Mr. Ken Tamms of the AEP Service Corporation reviewed the merchant plant analysis. A handout was provided to the Board, which indicated that [redacted].

At the request of Mr. Akins, Mr. Brodt provided information and discussed OVEC's year-to-date power costs estimated for 2016 and projections for 2017-2021. Mr. Brodt stated that based on current estimates OVEC expected to end 2016 with an average power cost of [redacted] and an available power use factor of [redacted]. Mr. Brodt stated that the projected average power cost for OVEC power, delivered under the terms of the Inter-Company Power Agreement, ranges from [redacted] to [redacted] using an estimated available power use factor of [redacted].

Mr. Akins asked Mr. Scott Cunningham to report on the OVEC Operating Committee. Mr. Cunningham reported that the Operating Committee recommended a fuel cost policy revision to use replacement fuel cost versus weighted cost of inventory. This revision is expected to be made during the first quarter 2017. The Operating Committee made no recommendation to the Board to proceed with the integration of the OVEC-IKEC transmission system into PJM.

At the request of Mr. Akins, Mr. Brodt reported on the status of the Corporation's finances. Mr. Brodt distributed to all members present a copy of the Treasurer's Report that included the following statistics:

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OHIO VALLEY ELECTRIC CORPORATION (OVEC)
INDIANA-KENTUCKY ELECTRICCORPORATION (IKEC)
Treasurer's Report
Boards of Directors' Meeting
December 1, 2016

	OVEC	IKEC	Consolidated
EQUITY			
Common Stock, 100,000 shares outstanding	$ 10,000,000	$ 3,400,000	$ 10,000,000
Retained Earnings	8,653,536	-	8,653,536
Total Equity at October 31, 2016	$ 18,653,536	$ 3,400,000	$ 18,653,536
(OVEC's ownership of IKEC's Capital Stock (17,000 shares) is eliminated in consolidation.)			
CASH AND INVESTMENTS			
Cash and Short-Term Investments	$ 46,793,706	$ -	$ 46,793,706
Employee PRB Benefits Reserve Account	77,697,759	-	77,697,759
Total Cash and Investments at October 31, 2016	$ 124,491,465	$ -	$ 124,491,465
DIVIDENDS			
Total 2016 Dividends	$ -	$ -	$ -
LONG-TERM DEBT			
2006 Senior Unsecured Notes, Series A, 5.80%, due February 15, 2026	$ 227,600,578	$ -	$ 227,600,578
2006 Senior Unsecured Notes, Series B, 6.40% due June 15, 2040	57,576,242	-	57,576,242
2007 Senior Unsecured Notes, Series AA, AB & AC, 5.90%, due February 15, 2026	160,320,832	-	160,320,832
2007 Senior Unsecured Notes, Series BA, BB & BC, 6.50% due June 15, 2040	43,682,246	-	43,682,246
2008 Senior Unsecured Notes, Series A, 5.92%, due February 15, 2026	33,231,642	-	33,231,642
2008 Senior Unsecured Notes, Series B & C, 6.71%, due February 15, 2026	131,104,353	-	131,104,353
2008 Senior Unsecured Notes, Series D & E, 6.91% due June 15, 2040	84,231,146	-	84,231,146
2013 Senior Unsecured Notes, Series A, Floating Rate, due February 15, 2016	100,000,000	-	100,000,000
2009 Tax Exempt Bonds, $100M Series A-D, Floating Rate, due February 1, 2026	100,000,000	-	100,000,000
2009 Tax Exempt Bonds, $100M Series E, 5.625%, due October 1, 2019	100,000,000	-	100,000,000
2010 Tax Exempt Bonds, $100M Series A & B, Floating Rate, due February 1, 2040	100,000,000	-	100,000,000
2012 Tax Exempt Bonds, $200M Series A, 5%, due June 1, 2039	200,000,000	-	200,000,000
2012 Tax Exempt Bonds, $100M Series B & C, Floating Rate, due June 1, 2040	100,000,000	-	100,000,000
Total Long-Term Debt Outstanding at October 31, 2016	$ 1,437,747,039	$ -	$ 1,437,747,039
SHORT-TERM DEBT			
Total Short-Term Debt Outstanding at October 31, 2016	$ 85,000,000	$ -	$ 85,000,000
EMPLOYEE BENEFIT PLAN ASSETS			
Pension Plan			$ [redacted]
Supplemental Pension & Savings Plan			
Union Retiree Medical VEBA Trust			
Retiree Medical VEBA Trust			
Retiree Life Insurance VEBA Trust			
401(h)			
Total Benefit Plan Assets at October 31, 2016			$
PLANT DECOMMISSIONING & DEMOLITION (D&D) FUND			
Total D&D Assets at October 31, 2016	$ 19,001,239	$ 26,239,806	$ 45,241,045

Mr. Akins introduced Mr. Bob Bitter of Deloitte & Touche. Mr. Bitter reported that Deloitte & Touche just began its audit to certify the 2016 Financial Statements that would be finalized in April 2017.

The Board moved to an Executive Session.

There being no further business to come before the Board, the meeting was adjourned.

Secretary
OHIO VALLEY ELECTRIC CORPORATION

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OHIO VALLEY ELECTRIC CORPORATION
Minutes of Special Meeting of the
Board of Directors' Meeting via Teleconference
January 30, 2017

A Special Meeting of the Board of Directors of **OHIO VALLEY ELECTRIC CORPORATION** (OVEC) via teleconference was called to order by the President on Monday, January 30, 2017, at 8:45 a.m., pursuant to notice duly given.

Nicholas K. Akins, President of the Corporation, acted as Chairman of the meeting, and John D. Brodt, Chief Financial Officer, Secretary and Treasurer of the Corporation, acted as Secretary of the meeting.

Mr. Brodt reported that the following Directors were present for the meeting:

Nicholas K. Akins	Mark E. Miller
Thomas Alban	Steven K. Nelson
Eric D. Baker	Patrick W. O'Loughlin
Lee E. Barrett	David W. Pinter
Wayne D. Games	Julie Sloat
Mark C. McCullough	Paul W. Thompson

John N. Voyles, Jr.

Mr. Akins advised that Donald A. Moul would be resigning from the OVEC and IKEC Boards of Directors and as a member of both Executive Committees, pending the election of his replacement. Mr. Akins recommended that Mr. David W. Pinter, Executive Director, Business Development for FirstEnergy Corp., be nominated to succeed Mr. Moul on both the OVEC and IKEC Boards of Directors and be appointed to the Executive Committees of both OVEC and IKEC. Mr. Akins also recommended that Lee E. Barrett be appointed to the OVEC Executive Committee. On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that subject to any necessary action by the Federal Energy Regulatory Commission under Section 305 of the Federal Power Act, Mr. David W. Pinter be elected a Director and appointed a member of the Executive Committee of this Corporation; and further
>
> **RESOLVED**, that subject to any necessary action by the Federal Energy Regulatory Commission under Section 305 of the Federal Power Act, Mr. Lee E. Barrett be appointed a member of the Executive Committee of this Corporation.

Mr. Akins asked Mr. Justin Cooper to review the handout, "OVEC in PJM Cost/Benefit Analysis," prepared by the OVEC Operating Committee. Mr. Cooper reported that a [redacted]

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[redacted]. He also stated that some costs are approximations and difficult to quantify at this time. The Board provided feedback to Mr. Cooper for OVEC to review the possible additional benefit from energy value from changing the delivery point.

At the request of Mr. Akins, Mr. Brian Chisling, with Simpson Thacher & Bartlett LLP, highlighted the plan of OVEC moving forward with the process of applying for membership in PJM. The motion was duly made and seconded. The resolution was adopted based upon a vote of [redacted]. The motion was approved as

> **RESOLVED**, that Ohio Valley Electric Corporation is to move forward with the process of applying for membership in PJM to further validate assumptions prior to a final Board vote to join PJM.

There being no further business to come before the Board, the meeting was adjourned.

Secretary
OHIO VALLEY ELECTRIC CORPORATION

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OHIO VALLEY ELECTRIC CORPORATION

Minutes of Special Meeting of the

Board of Directors held December 8, 2017

A Special Meeting of the Board of Directors of **OHIO VALLEY ELECTRIC CORPORATION** (OVEC) was called to order by the President at 1 Riverside Plaza, Columbus, Ohio, on Friday, December 8, 2017, at 2:00 p.m., pursuant to notice duly given.

Nicholas K. Akins, President of the Corporation, acted as Chairman of the meeting, and John D. Brodt, Chief Financial Officer, Secretary and Treasurer of the Corporation, acted as Secretary of the Meeting.

Mr. Brodt reported that the following Directors were present for the meeting:

Nicholas K. Akins	Mark C. McCullough
Thomas Alban	Steven K. Nelson
Lonnie E. Beller	Patrick W. O'Loughlin
Wayne D. Games	David W. Pinter (Phone)
James R. Haney (Phone)	Paul W. Thompson
Lana L. Hillebrand	John A. Verderame

Mr. Brodt reported that the Minutes of the Special Meeting of the Board of Directors of this Corporation, held on December 1, 2016, have been sent to each of the Directors. He asked that, if there were no corrections, such minutes be approved in the form in which they were circulated. On a motion duly made, seconded, and unanimously adopted, it was

RESOLVED, that the Minutes of the Special Meeting of the Board of Directors of this Corporation, held on December 1, 2016, are approved.

At the request of Mr. Akins, Mr. Brodt reviewed the 2017 Service Corporation general expenditures, which were expected to be approximately [redacted]. Mr. Brodt requested authorization for 2018 general expenditures for services from the AEP Service Corporation up to [redacted]. The primary general expenditures are expected to be in the areas of operation and maintenance, environmental activities, fuel procurement, and coal transportation. Mr. Brodt stated that the 2018 Budget is similar to the 2017 Budget except that the 2018 Budget request of [redacted] the 2017 Budget request of [redacted]. The [redacted]

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[redacted]. On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the officers of Ohio Valley Electric Corporation may request and obligate Ohio Valley Electric Corporation to pay for general services, exclusive of services for specific projects previously approved, under the Agreement among American Gas and Electric Service Corporation (now American Electric Power Service Corporation), Ohio Valley Electric Corporation, and Indiana-Kentucky Electric Corporation dated December 15, 1956, in an amount which, when added to amounts paid for general services by Indiana-Kentucky Electric Corporation, exclusive of services for specific projects previously approved, would aggregate a maximum of [redacted] for calendar year 2018.

At the request of Mr. Akins, Mr. Justin Cooper reported on the 2018 LEAN demand costs. Mr. Cooper reviewed the results of the 2017 continuous improvements (LEAN) reductions and the operating, maintenance, and capital cost benchmarking budgets. Mr. Cooper reported that OVEC's operating, maintenance, and capital cost profile was projected to [redacted] in 2018 compared with 2013. The energy cost [redacted].

Mr. Akins asked Mr. Mike Brown to give an update on the OVEC and IKEC environmental compliance status and to report on the work to develop cost estimates for future environmental capital projects. Mr. Brown reported that the OVEC and IKEC 2017 ozone season NO_x performance was better than expected. The 2017 ozone season NO_x emissions were reduced by approximately [redacted] at Kyger Creek and [redacted] at Clifty Creek compared with the 2012-2016 average. Mr. Brown reported on the status of developing cost estimates to comply with Effluent Limitations Guidelines, [redacted], and Kyger Creek dry fly ash conversion. In addition, Mr. Brown provided an update on cost estimates to comply with Section 316(b) and the Coal Combustion Residual (CCR) rule. OVEC's current environmental capital investment "best-case" cost estimate for these projects is [redacted], and the current "worst-case" cost estimate is [redacted]. An investment decision for additional funding for conceptual engineering and design will be required by mid-year 2019 to mid-year 2020.

Mr. Akins asked Mr. Cooper to review the 2018 Construction Budget and the 2019-2022 Construction Budget Forecast. Mr. Cooper commented that the 2018 Construction Budget is a [redacted] compared with the original 2018 budget forecast with prioritization of

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economic benefit, risk, and fiscal impact. Mr. Cooper reported that the Construction Budget for 2018 indicates estimated total expenditures of [redacted], representing [redacted] On a motion duly made, seconded, and unanimously adopted, it was

> **RESOLVED**, that the OVEC-IKEC Construction Budget for 2018, indicating estimated total expenditures of [redacted]

Mr. Akins asked Mr. Osborne to report on operating activities for the Clifty Creek and Kyger Creek plants. Mr. Osborne reviewed the operating statistics and the results of the 2017 Culture Survey. Mr. Osborne recognized that the Clifty Creek employees completed one year without a recordable injury. Mr. Osborne asked Clifty Creek Plant Manager Cliff Carnes and Kyger Creek Plant Manager Annette Hope to report on the 2017 Strategic Plan for each respective location highlighting three areas of success and three areas of opportunities.

Mr. Akins asked Mr. Scott Cunningham to report on the OVEC Operating Committee. Mr. Cunningham reviewed a projected OVEC-PJM integration timeline of the basic steps OVEC intends to pursue regarding full integration into PJM.

At the request of Mr. Akins, Mr. Brodt reported on the status and timeline of the Corporation's finance activities. Mr. Brodt distributed to all members present a copy of the Treasurer's Report that included the following statistics:

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INFORMATION
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**OHIO VALLEY ELECTRIC CORPORATION (OVEC)
INDIANA-KENTUCKY ELECTRIC CORPORATION (IKEC)
Treasurer and Finance Report
Boards of Directors' Meeting
December 8, 2017**

	OVEC	IKEC	Consolidated
CASH AND INVESTMENTS			
Cash and Short-Term Investments	$ 53,878,779		$ 53,878,779
Employee PRB Benefits Reserve Account	71,625,576		71,625,576
Debt Reserve Account	20,306,082		20,306,082
Total Cash and Investments at October 31, 2017	$ 145,810,437		$ 145,810,437
PLANT DECOMMISSIONING & DEMOLITION (D&D) FUND			
Total D&D Assets at October 31, 2017	$ 21,892,091	$ 30,195,452	$ 52,087,543
EMPLOYEE BENEFIT PLAN ASSETS			
Pension Plan			$ [redacted]
Supplemental Pension & Savings Plan			
Union Retiree Medical VEBA Trust			
Retiree Medical VEBA Trust			
Retiree Life Insurance VEBA Trust			
Retiree Medical 401(h)			
Total Benefit Plan Assets at October 31, 2017			$
EQUITY			
Common Stock, 100,000 shares outstanding	$ 10,000,000	$ 3,400,000	$ 10,000,000
Retained Earnings	9,893,759	-	9,893,759
Total Equity at October 31, 2017	$ 19,893,759	$ 3,400,000	$ 19,893,759
(OVEC's ownership of IKEC's Capital Stock (17,000 shares) is eliminated in consolidation.)			
LONG-TERM DEBT			
2006 Senior Unsecured Notes, Series A, 5.80%, due February 15, 2026	$ 209,037,387		$ 209,037,387
2006 Senior Unsecured Notes, Series B, 6.40% due June 15, 2040	56,503,080		56,503,080
2007 Senior Unsecured Notes, Series AA, AB & AC, 5.90%, due February 15, 2026	147,593,370		147,593,370
2007 Senior Unsecured Notes, Series BA, BB & BC, 6.50% due June 15, 2040	42,890,007		42,890,007
2008 Senior Unsecured Notes, Series A, 5.92%, due February 15, 2026	30,595,859		30,595,859
2008 Senior Unsecured Notes, Series B & C, 6.71%, due February 15, 2026	120,374,809		120,374,809
2008 Senior Unsecured Notes, Series D & E, 6.91% due June 15, 2040	82,747,579		82,747,579
2017 Senior Unsecured Notes, Series A, Floating Rate, due August 4, 2022	100,000,000		100,000,000
2009 Tax Exempt Bonds, $100M Series A-D, Floating Rate, due February 1, 2026	75,000,000		75,000,000
2009 Tax Exempt Bonds, $100M Series E, 5.625%, due October 1, 2019	100,000,000		100,000,000
2010 Tax Exempt Bonds, $100M Series A & B, Floating Rate, due February 1, 2040	100,000,000		100,000,000
2012 Tax Exempt Bonds, $200M Series A, 5%, due June 1, 2039	200,000,000		200,000,000
2012 Tax Exempt Bonds, $100M Series B & C, Floating Rate, due June 1, 2040	100,000,000		100,000,000
Total Long-Term Debt Outstanding at October 31, 2017	$ 1,364,742,091		$ 1,364,742,091
SHORT-TERM DEBT			
$200M Revolving Credit Facility (extension date November 14, 2019)			
Total Short-Term Debt Outstanding at October 31, 2017	$ 85,000,000		$ 85,000,000
CORPORATE UNSECURED CREDIT RATINGS			
Standard & Poor's (rating affirmed February 13, 2017)	BBB-, Stable Outlook		
Fitch (rating affirmed November 14, 2017)	BBB-, Negative Outlook		
Moody's (rating downgrade December 20, 2016)	Ba1, Negative Outlook		

FINANCE WORKING GROUP

[redacted]

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At the request of Mr. Akins, Mr. Brodt provided information and discussed OVEC's year-to-date power costs estimated for 2017 and projections for 2018-2022. Mr. Brodt stated that based on current estimates OVEC expected to end 2017 with an average power cost of [redacted] and an available power use factor of [redacted]. Mr. Brodt stated that the projected average power cost for OVEC power, delivered under the terms of the Inter-Company Power Agreement, ranges from [redacted] in 2018 to [redacted] in 2022 using an estimated available power use factor of [redacted].

Mr. Akins introduced Mr. Bob Bitter of Deloitte & Touche. Mr. Bitter reported that Deloitte & Touche just began its audit to certify the 2017 Financial Statements that would be finalized in April 2018.

The OVEC and IKEC Boards of Directors recognized John D. Brodt for his contributions to the corporations upon his upcoming January 1, 2018, retirement from the Company. On a motion duly made, seconded, and unanimously adopted

> **WHEREAS**, John D. Brodt has provided exemplary leadership and guidance to OVEC-IKEC during a period of unprecedented change in the electric utility industry throughout his career; and
>
> **WHEREAS**, John D. Brodt has drawn upon the wisdom and experience he has gained as Secretary and Treasurer/Chief Financial Officer, which enabled him to provide dedicated and effective service to the Company, to the electric utility industry and to his community during a tenure as Secretary and Treasurer/Chief Financial Officer that began in 1988.
>
> **NOW, THEREFORE BE IT**
>
> **RESOLVED**, that John D. Brodt is recognized by the Directors of OVEC and IKEC for his steadfast commitment and superb judgment throughout his years of illustrious service to the Company; and further
>
> **RESOLVED**, that the Directors of OVEC and IKEC hereby acknowledge the important contributions made by John D. Brodt to the success, growth and well-being of the Company during a most challenging period in his history; and further
>
> **RESOLVED**, that the Directors of OVEC and IKEC thank John D. Brodt for his 41 years of service and extend their best wishes upon his upcoming retirement from the Company, along with their sincere desire that his retirement years will be long, enjoyable and fulfilling; and further
>
> **RESOLVED**, that a copy of these resolutions and their preambles shall be delivered to John D. Brodt as an expression of the deep appreciation and hearty good wishes of the Directors of OVEC and IKEC upon his retirement.

The Board moved to an Executive Session.

There being no further business to come before the Board, the meeting was adjourned.

Secretary
OHIO VALLEY ELECTRIC CORPORATION

I-Case No. U-20804
SC Set 4, Q10

Itemized monthly charges by AEG to Indiana Michigan Power Company for Rockport Pla

Note: AEG does not have transmission charges, minimum loading events or ISO/RTO e

Sum of Amount		Type		
Year	Period	Demand	Energy	Grand Total
2015	1	8,632,654	13,046,325	21,678,979
	2	9,706,531	7,831,627	17,538,158
	3	10,582,437	5,165,464	15,747,901
	4	8,917,346	8,321,087	17,238,433
	5	8,265,925	11,394,210	19,660,135
	6	9,332,951	13,761,772	23,094,723
	7	11,438,157	14,850,669	26,288,826
	8	10,452,850	12,542,645	22,995,495
	9	11,412,244	6,584,244	17,996,488
	10	11,188,535	8,233,694	19,422,229
	11	7,629,400	4,805,381	12,434,781
	12	12,689,778	5,322,034	18,011,812
2015 Total		120,248,808	111,859,152	232,107,960
2016	1	10,902,725	7,299,689	18,202,414
	2	10,492,760	5,492,741	15,985,501
	3	9,282,826	1,938,746	11,221,572
	4	9,062,492	8,276,799	17,339,291
	5	10,079,581	8,503,840	18,583,421
	6	10,352,600	9,728,262	20,080,862
	7	10,186,794	12,749,608	22,936,402
	8	10,216,519	13,015,328	23,231,847
	9	10,510,159	7,847,722	18,357,881
	10	9,915,144	9,524,840	19,439,984
	11	9,959,597	9,862,076	19,821,673
	12	10,762,759	12,564,482	23,327,241
2016 Total		121,723,956	106,804,133	228,528,089
2017	1	10,299,038	10,270,040	20,569,078
	2	10,204,230	8,227,710	18,431,940
	3	10,751,940	4,157,637	14,909,577
	4	10,416,980	2,982,179	13,399,159
	5	10,665,828	6,894,030	17,559,858
	6	10,770,469	8,187,643	18,958,112
	7	10,439,378	12,417,902	22,857,280
	8	10,880,469	10,544,482	21,424,951
	9	11,581,284	6,571,285	18,152,569
	10	10,515,390	8,685,816	19,201,206
	11	10,207,984	4,387,875	14,595,859
	12	11,000,075	12,839,828	23,839,903
2017 Total		127,733,065	96,166,427	223,899,492
2018	1	11,385,786	13,503,608	24,889,394
	2	10,204,741	6,698,063	16,902,804
	3	10,309,385	9,293,788	19,603,173
	4	10,616,309	8,433,042	19,049,351
	5	10,545,375	8,159,141	18,704,516
	6	10,992,074	11,730,088	22,722,162
	7	10,632,079	8,830,253	19,462,332
	8	10,835,471	10,233,208	21,068,679
	9	11,371,385	8,058,464	19,429,849

I-Case No. U-20804
SC Set 4, Q10

2018	10	10,919,408	6,183,190	17,102,598
	11	13,889,699	6,691,905	20,581,604
	12	11,709,720	6,681,995	18,391,715
2018 Total		133,411,432	104,496,745	237,908,177
2019	1	11,063,563	10,157,495	21,221,058
	2	11,022,173	8,353,784	19,375,957
	3	13,585,304	5,538,558	19,123,862
	4	9,549,681	10,143,885	19,693,566
	5	10,203,056	7,564,917	17,767,973
	6	10,737,870	3,184,175	13,922,045
	7	12,603,542	12,002,443	24,605,985
	8	12,871,432	6,143,194	19,014,626
	9	10,432,088	6,974,094	17,406,182
	10	11,710,542	3,371,916	15,082,458
	11	9,526,941	6,184,760	15,711,701
	12	11,322,402	615,520	11,937,922
2019 Total		134,628,594	80,234,741	214,863,335
2020	1	10,490,153	1,077,659	11,567,812
	2	10,025,735	2,165,297	12,191,032
	3	10,471,895	1,905,498	12,377,393
	4	10,248,203	3,934,932	14,183,135
	5	9,862,285	3,056,142	12,918,427
	6	9,949,943	6,708,675	16,658,618
	7	12,333,059	5,025,475	17,358,534
	8	12,796,260	6,372,126	19,168,386
	9	14,172,068	5,160,926	19,332,994
	10	12,510,080	57,143	12,567,223
	11	9,452,201	4,794,174	14,246,375
	12	10,139,067	84,702	10,223,769
2020 Total		132,450,949	40,342,749	172,793,698
(blank)	(blank)			
(blank) Total				
Grand Total		770,196,804	539,903,947	1,310,100,750

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **INDIANA MICHIGAN POWER COMPANY** for approval to implement a power supply cost recovery plan for the twelve months ending December 31, 2021.	U-20804 ALJ Kandra Robbins

PROOF OF SERVICE

On the date below, an electronic copy of **the PUBLIC Testimony of Devi Glick on behalf of Sierra Club and Exhibit SC-1 through SC-16** was served on the following:

Name/Party	E-mail Address
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The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for Sierra Club

Date: March 12, 2021

Digitally signed by Kimberly Flynn
DN: cn=Kimberly Flynn, o=Olson Bzdok & Howard, P.C., ou, email=kimberly@envlaw.com, c=US
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By: ______________________________

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