October 23, 2020

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-20224

Dear Ms. Felice:

The following is attached for paperless electronic filing:

Public Version of the Direct Testimony of Devi Glick on behalf of Sierra Club

Exhibits SC-1 through SC-7, SC-9 through SC-20 (SC-8 is Confidential)

Proof of Service

Sincerely,

Digitally signed by Christopher M. Bzdok
DN: cn=Christopher M. Bzdok, email=chris@envlaw.com, c=US
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Christopher M. Bzdok
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xc: Parties to Case No. U-20224

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of 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.	U-20224 ALJ Dennis Mack

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DIRECT TESTIMONY OF DEVI GLICK

ON BEHALF OF

SIERRA CLUB

PUBLIC VERSION

October 23, 2020

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I. 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 Indiana, Wisconsin, Texas, Arizona, New Mexico, Connecticut, Virginia, North Carolina, South Carolina, and Florida. 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 seven 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 No.

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

A In this proceeding I review and evaluate the prudence of Indiana Michigan Power Company's ("I&M" or "Company") power supply cost and unit commitment decisions and related fuel costs for the 12-month period beginning January 1, 2019 and ending December 31, 2019. Specifically, I review and evaluate I&M's justifications for operating the Rockport Generating Station ("Rockport") out of merit order and purchasing energy from its affiliate, Ohio Valley Electric Corporation ("OVEC"), at above-market prices. I also discuss potential concerns with the accuracy and transparency of the Company's reported fuel costs.

Q How is your testimony structured?

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

In Section III.A, I discuss how coal units are committed in PJM, define uneconomic self-commitment, and describe the types (and magnitude) of customer losses that can result from must-run commitment decisions. I describe how I&M makes unit commitment determinations for Rockport and I assess how often I&M committed each Rockport unit into the PJM market with "must-run" versus "economic" status during 2019. I evaluate the information that I&M had at the time it made each unit commitment decision at Rockport during 2019 and therefore what the Company knew about how much the plant was likely to earn or lose relative to the market.

In Section III.B, I summarize the actual performance of Rockport during 2019 and I calculate the costs that uneconomic commitment practices will impose on ratepayers if approved for recovery in this proceeding. I also discuss the concerning discrepancy between the Company's reported marginal fuel cost and actual fuel receipts and explain how this discrepancy impacts both how fuel costs are passed onto customers and how the Company makes unit commitment decisions.

In Section III.C, I summarize actions by other state utility commissions and market monitors to address similar concerns about utility commitment practices in other jurisdictions.

In Section III.D, I outline my recommendations for the Commission to disallow cost incurred by I&M if it does not follow price-based signals and make prudent unit commitment decisions moving forward.

In Section IV.A, I discuss I&M's Inter-Company Power Agreement ("ICPA") with OVEC. I summarize details of the contract, discuss how the contract was never approved by the

Michigan Public Service Commission ("MPSC"), explain how OVEC is an affiliate of I&M, express my concerns with the affiliate agreement, and evaluate the costs that this contract is incurring for ratepayers relative to the cost of market purchases from PJM.

Finally, in Section IV.B, I recommend that the Commission cap I&M's recovery of the Michigan jurisdictional share of compensation for the ICPA.

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. In addition, I rely to a limited extent on certain external, publicly available documents such as the Southwest Power Pool's ("SPP") 2018 State of the Market Report.

II. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. I&M regularly self-commits Rockport Units 1 and 2.
2. I&M self-committed Rockport Unit 1 and 2 despite projecting net operational losses from committing the unit as must-run in 3 out of 12 months at Rockport 1 and for 6 out of 12 months at Rockport 2 in 2019.
3. I&M's unit commitment practices at Rockport led to over [[redacted]] in net losses between January 1 and December 31, 2019 and excess costs that the Company seeks to recover from ratepayers that total [[redacted]].

4. I&M likely does not accurately and transparently account for all fuel costs in making its unit commitment decisions.
5. I&M purchases power from OVEC, an affiliate company, at above-market prices and passes the unnecessary costs on to ratepayers.

Q Please summarize your recommendations.

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

1. The Commission should disallow recovery of [[[redacted]]], which represents Michigan's jurisdictional share of the [[[redacted]]] in fuel costs out of the [[[redacted]]] in unnecessary variable costs incurred based on uneconomic unit commitment practices at Rockport. These losses were avoidable if I&M had followed the results of its own price-based process and therefore should not be passed onto ratepayers.
2. The Commission should, in all future reconciliation dockets, disallow losses incurred at Rockport Units 1 and 2 if I&M does not follow price-based signals to make prudent unit commitment decisions.
3. I&M should provide the following in each reconciliation filing to allow a review of the prudence of its unit commitment practices:
    a. All Profit and Loss analysis sheets used to develop the Company's daily unit commitment decisions and market bids.
    b. A brief description memorializing the reason for any deviation between the results of the Company's forward-looking price-based analysis and the Company's actual commitment decision.

c. Hourly data sufficient for the Commission to calculate the net revenues that each plant actually incurred in each reconciliation period, including total unit generation, accounting "as burned" fuel cost, marginal or "replacement" fuel cost, total variable operations and maintenance ("O&M") cost, unit locational marginal price ("LMP"), day-ahead commitment status, energy and ancillary market revenues, and actual outages.

4. The Commission disallow in this proceeding $2,557,952, Michigan's jurisdictional share of the total $18,343,791 in excess cost that I&M paid for OVEC services under the ICPA (relative to the market value of the services).
5. In all future reconciliation dockets, the Commission should disallow recovery of ICPA costs above the 2019 equivalent market costs for those products and services, as determined by the value of energy, ancillary services, and market prices for capacity as delivered at OVEC's zone.

III. I&M IS IMPRUDENTLY SELF-COMMITTING ROCKPORT AT EXCESS COST TO RATEPAYERS

Q Please summarize this section.

A In this section, I explain how dispatchable power plants operate within the PJM market and why so many coal plants are committed in the market with a must-run status. I define the practice of uneconomic self-commitment and discuss the impacts this practice has on ratepayers. I describe the tools that utilities broadly, and I&M in particular, use to evaluate the prudence of their unit commitment decisions. I review the Company's own data and find that I&M commits the Rockport units with a must-run status the majority of the time the units are available. I also review the profit and loss analysis that I&M uses to inform its unit commitment decision. I find at least six instances where the Company kept one of the Rockport units online and sustained significant losses despite its own projections indicating a benefit to ratepayers in turning the unit off. Next, I outline my concerns with the lack of transparency and discrepancies in the Company's reported fuel costs and explain the impact that these discrepancies could have on I&M's reported plant economics and its unit commitment decisions. Then I provide for the Commission an outline of other venues and dockets where state agencies have exercised increased oversight of unit commitment. Finally, I end the section with recommendations for the Commission regarding a disallowance in this case and requirements for future reconciliation dockets.

A. I&M SELF-COMMITS ROCKPORT UNITS 1 AND 2 THE MAJORITY OF THE TIME THEY ARE AVAILABLE

Q Please describe how dispatchable power plants are generally committed within the PJM wholesale market.

A Generators operating within the PJM market commit their units with one of three statuses: economic, must-run, and outage. In PJM, utilities generally commit dispatchable generating units with a status of "economic."[1] For those units, the market operator has the responsibility for unit commitment and operational decisions. Those decisions prioritize

[1] 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.

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.

Q In practice, are all power plants actually committed in this way?

A Not necessarily. For units with long startup and shutdown times, such as coal-fired power plants, utilities often elect to maintain control of unit commitment decisions and design independent processes outside of the PJM market to determine when to commit a unit at its minimum operating level.[2] Unlike the market operator, generation owners may choose not to incorporate costs into their decision-making process and may elect to commit units as "must-run" regardless of economics.

In making the self-commitment decision, the generation owner, in this case I&M, independently decides to operate a unit regardless of PJM's determination of economic unit commitment or dispatch. This is in contrast to economic unit commitment, where PJM algorithms compare the variable cost of operating (and starting) a unit to determine the relevant variable costs of all other units available to the market to determine whether the unit will be online the next day. A plant committed as "economic" will operate only if it is the least-cost option available to the market (i.e., lower cost than the marginal resource at that time). Once a plant is online, regardless of how it was committed, the market operator

[2] 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.

may economically dispatch the unit by ramping it up and down from that minimum operating level based on the units' relative variable operating cost.

Q What happens if a unit is committed with a must-run status?

A A unit designated as must-run will operate with a power output no less than its minimum operating level. 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 the utility often seeks to recover from ratepayers.

Q How should a utility decide whether to commit a unit as must-run?

A To **properly** anticipate the net benefits likely to result from the decision to commit a unit into the market with a must-run designation, and therefore ensure that a commitment decision has a net positive outcome, an operator like I&M has to create market price projections extending several days into the future.

Unfortunately, there is no actual requirement in Michigan that operators create these projections. The operator is free to self-commit its slow-ramping coal-fired units without any understanding of the net benefits that will result.

Q What does the phrase "uneconomic self-commitment" mean?

A The term uneconomic self-commitment refers to a utility's decision to commit a unit into the PJM market with a "must-run" status when it knows that market energy and ancillary service revenues are not sufficient to cover fuel and variable operating costs.

Day-ahead market prices are known with certainty for the next day and can be projected with a sufficient level of accuracy, for the purposes of unit commitment, a few days out. Fuel and variable operation and maintenance costs are also known with relative certainty a few days out, and start-up costs are known and should not fluctuate significantly over the course of the week. This means that at the time the utility makes a decision to self-commit a unit in the day-ahead market (i.e., to either bring the unit online, keep it online, take it offline, or keep it offline) it has the information needed to make a prudent decision. That decision should maximize projected net revenues/minimize projected net losses to ratepayers over a several-day period.

Q Should a utility be considered to have made an imprudent decision any time it doesn't maximize actual revenues to ratepayers?

A Not necessarily. Utilities are expected to use accurate cost and pricing information and to make prudent decisions based on that information, but they are not expected to always be right. If market prices deviate significantly from what the utility reasonably projected, the company's self-commitment decisions may not actually maximize net revenues. But in order to be prudent, the utility's decision to self-commit its unit must have been projected to maximize net revenues at the time the company made the must-run commitment decision.

Q What tools does I&M have to inform its unit commitment decisions?

A I&M has developed a price-based forward-looking analysis process. I&M conducts this analysis every day to determine whether to commit its units the next day. The Company records all revenue projections and commitment decisions for the following day on a sheet I will refer to as the "Profit and Loss" analysis sheet.[3]

In these assessments, the Company reviews forecasted energy market prices and projected variable operational costs for the next six days to project net operational revenues (or losses) for each unit for each individual day and over the entire 6-day period.[4] If a unit is projected to be profitable, then ratepayers expect to see savings from operating the unit relative to the acquisition of market-supplied power. If the unit is projected to lose money, then ratepayers expect to see savings by the acquisition of market-supplied power.

Q How should I&M be using the results of its price-based analysis to inform unit commitment decisions?

A I&M should either (a) commit its units as economic and let the market decide when to operate the units, or (b) make unit commitment decisions based on the results of its price-based analysis and document any deviations from its quantitative analysis. Specifically, I&M should elect to self-commit its units as must run on a forward-looking basis only if it expects to make positive energy market margins over a reasonable near-term time period (incorporating consideration of start-up and shut-down costs), and the Company should commit it as "economic" with the expectation it will not run if it is projected to operate at a loss.

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[3] The Company produced a selection of these sheets as I&M Response to Sierra Club Request 1.05(dii), CONFIDENTIAL Attachments (65 total).

[4] I&M Response to Sierra Club Request 1.05(a) and (c).

Q Does I&M follow its price-based analysis to make its unit commitment decision at Rockport Units 1 and 2?

A No. I&M does not always rely on the results of its Profit and Loss Analysis to inform its unit commitment decision at Rockport Units 1 and 2. Instead, as I discuss below, the Company regularly self-commits the units regardless of what its price-based analysis projects about unit performance.

Q How did I&M commit its Rockport Units 1 and 2 during the reconciliation period of January 1, 2019 through December 31, 2019?

A Based on the Company's unit commitment data, I find that during the reconciliation period, the Company self-committed (i.e., entered the unit into the PJM market with a must-run status) Rockport Units 1 and 2 the majority of the time that the units were available.[5]

Table 1: CONFIDENTIAL Unit commitment decisions for Rockport Units 1 and 2 (non-outage hours)

[redacted]

Sources: I&M Response to Sierra Club Request 1.01(e), SC 1.01e CONFIDENTIAL Attachment – 2019 Offer Status.xls.

Q Why do you present results for non-outage hours instead of total hours?

A During an outage, a generator has operational considerations outside of short-term energy market prices. Therefore, I excluded these hours to look only at the commitment elections when economics are the predominant consideration facing a unit. Specifically, I have

[5] I&M Response to Sierra Club Data Request 1.01(e), SC 1.01e CONFIDENTIAL Attachment – 2019 Offer Status.xls.

removed data from all planned and unplanned outage periods, as identified by the Company,[6] from all analysis performed throughout my testimony. However, it is important to note that unplanned outages can result from imprudent O&M planning decisions, and that increased operations can make it more likely that an unplanned outage will occur. The costs associated with unplanned outages are not captured in unit commitment analysis in the same way that the costs associated with normal unit cycling are (i.e., start-up costs). While an individual commitment decision is not necessarily responsible for causing an outage, a pattern of imprudent commitment decisions and unnecessary plant operation could be tied to an increased frequency of plant outages.

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

A It may be reasonable for I&M to take control of its unit commitment decisions if the utility demonstrates that its internal decision process produces greater net revenues and a more-economic outcome than relying solely on the PJM market. But I&M has not demonstrated this to be the case. 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.[7] However, the full cost is still incurred by I&M to run that plant. This means that the Michigan portion of fuel costs not economically incurred are passed onto I&M's Michigan

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6 I&M Response to Staff Data Request 1-05, CONFIDENTIAL Attachment 1-05; and I&M Response to Staff Data Request 1-07, CONFIDENTIAL Attachment 1-07.

7 The market revenue I&M receives includes energy and ancillary market revenue from both the day-ahead and real-time markets.

ratepayers in their monthly bills through the Power Supply Cost Recovery ("PSCR") clause.

Q What did you find regarding the Company's use of its unit commitment analysis?

A I found that the Company did not always use the results of its own analysis to determine its unit commitment decision. I&M's own unit commitment Profit and Loss Analysis shows that the Company made imprudent unit commitment decisions that resulted in net losses during many months of the reconciliation period. Projected net operational losses from committing the unit as must-run were negative in three out of 12 months at Rockport 1 and for six out of 12 months at Rockport 2.[8] This means net operational revenues would have been higher if the units had been economically committed during those months.

Q What did you find in reviewing the Company's individual Profit and Loss Analysis sheets?

A In reviewing the 65 individual Profit and Loss Analysis sheets that I&M made available in combination with the Company's actual unit cost and revenue data, I found multiple weeks or multi-day stretches of time where I&M committed one of the Rockport units as must-run despite its own analysis indicating that the Company would incur excess costs to keep the unit online. This means that at the time of the commitment decisions at issue, I&M knew, based on its own predictive analysis, that it would very likely have saved customers money if it instead allowed the units to be economically committed through the PJM market process. In these instances, an economic commitment status would have directed

[8] Calculations based on data provided in I&M response to Sierra Club 1-05(dii) CONFIDENTIAL Attachments (65 total).

the market to compare the variable cost (and the unit start-up cost) of each Rockport unit to the cost of other units available in the market. The Rockport units would not have been selected, and therefore would have been taken offline.

Specifically, I found six sustained periods of losses when the Company left Rockport Units 1 or 2 online despite its own commitment analysis projecting that customers would be better off if the units were taken offline. The details of each "event" are shown in Table 2 below. For each event, net losses exceed the unit start-up costs of [[[redacted]]] for Rockport 1 and [[[redacted]]] for Rockport 2,[9] meaning the Company incurred excess costs by forcing the unit to stay online. In total, these events incurred [[[redacted]]] in net losses and cost ratepayers an unnecessary [[[redacted]]] (taking into account the start-up cost for each unit), [[[redacted]]] of which is attributed to fuel costs.

Table 2: CONFIDENTIAL Event notes from I&M's Profit and Loss Analysis sheets for Rockport Units 1 and 2

[redacted]

[9] I&M Second Supplemental Response to Sierra Club Request 1-03 (a) and (b).

[redacted]

Sources: I&M Response to Sierra Club Request 1-01 (l,n,o), CONFIDENTIAL Attachment SC 1-1(l,n,o); I&M Response to Sierra Club Request 1-01(g), CONFIDENTIAL Attachment SC 1-0(g) CORRECTED; I&M Response to Staff Data Request 1-05, CONFIDENTIAL Attachment 1-05; I&M Response to Staff Data Request 1-07, CONFIDENTIAL Attachment 1-07; and I&M Response to Sierra Club Request 1-05(dii), CONFIDENTAL Attachments (65 total).

Q Were there any limitations on your analysis of the Company's Profit and Loss Analysis sheets?

A Yes. I only had access through discovery to one sheet for every six days. This sample of sheets contains projections to cover the entire reconciliation period, but critically only provides the most current data the Company had available at the time it made each unit commitment decision for one out of every six days. As I will discuss in the recommendations section, for the best possible analysis the Commission should require I&M to make available to the Commission and intervenors all data used to make its daily commitment decisions.

Q How did you calculate these values discussed above?

A I reviewed 65 of the Profit and Loss Analysis sheets that the Company prepared to make unit commitment decisions for the year 2019. As mentioned above, each sheet contained projections for the next six days. To calculate the *projected* revenue or losses displayed in Table 2, I summed the daily *projected* net revenues or losses from the Profit and Loss Analysis sheet for the date range indicated. To calculate the actual net revenue or losses associated with those days, I summed the marginal variable costs and the market revenues to find a total net market revenue. Finally, I compared the net market revenue to the unit start-up cost to determine if the utility would have been better off taking the unit offline.

Q What exactly does the analysis from the Profit and Loss Analysis represent?

A The data provided in the Profit and Loss analysis sheets represents the information that the Company has on market prices and unit costs at the time it is making its unit commitment decisions. While it is true that market prices and other market inputs are constantly changing, there is a knowable set of information on unit costs and market prices at the time commitment decisions are made and submitted to PJM. Regardless of whether prices may continue to change, the Company can and should save the full set of information it has at the time of its decisions to allow the Commission to assess the prudency of its decisions.[10]

B. I&M'S OWN DATA SHOWS THAT THE COMPANY GENERATED NET REVENUES OF [[[redacted]]] OVER THE MONTHS JANUARY 1, 2019–DECEMBER 31, 2019, BUT THIS RESULT IS LIKELY BASED ON AN INCOMPLETE ACCOUNTING OF THE UNIT'S VARIABLE COST OF OPERATION

Q Please summarize the actual performance of Rockport's units during 2019 based on the Company's actual operational data.

A I reviewed data reported by I&M on the marginal variable costs that the Company incurred (fuel and variable O&M) and the actual energy market revenues that I&M earned from operation of its coal fleet in 2019. As shown in Table 3, I found that during 2019, the Rockport units combined earned net revenues of [[[redacted]]].[11] Rockport Unit 1 was largely unavailable and in outage for the last four months of the year.

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[10] I&M Response to Sierra Club Request 1-05(dii), CONFIDENTIAL Attachments (65 total).

[11] I&M Response to Sierra Club Request 1-01 (l,n,o), CONFIDENTIAL Attachment SC 1-1(l,n,o); I&M Response to Sierra Club Request 1-01(g), CONFIDENTIAL Attachment SC 1-0(g) CORRECTED; I&M Response to Staff Data Request 1-05, CONFIDENTIAL Attachment 1-05; and I&M Response to Staff Data Request 1-07, CONFIDENTIAL Attachment 1-07.

Table 3: CONFIDENTIAL Net Revenue ($Million) at Rockport Units 1 and 2

[redacted]

Source: I&M Response to Sierra Club Request 1-01 (l,n,o), CONFIDENTIAL Attachment SC 1-1(l,n,o); I&M Response to Sierra Club Request 1-01(g), CONFIDENTIAL Attachment SC 1-0(g) CORRECTED; I&M Response to Staff Data Request 1-05, CONFIDENTIAL Attachment 1-05; and I&M Response to Staff Data Request 1-07, CONFIDENTIAL Attachment 1-07.

Q How were the values in Table 3 calculated?

A I calculated the values in Table 3 based on the Company's own hourly cost and operational revenue data. The Company provided hourly marginal variable production cost values (which includes fuel and variable O&M) and hourly generation, which I multiplied together to get total variable production cost. I based my calculations on marginal "replacement" fuel costs as opposed to the booked cost of the fuel burned based on prior rulings by the MPSC that the replacement cost of coal, and not the as-burned cost, should be used to evaluate the Company's decision to offer its coal-fired plants.[12] I then calculated net operational revenues by comparing the total variable production costs to the operational

[12] MPSC Case No. U-17678-R, Order, Feb. 5, 2018, pp. 14-20.

revenues (energy and ancillary service revenues) provided by the Company. I removed losses incurred during planned and unplanned outages (as identified by the Company),[13] and then I summed the net hourly revenues for each hour in a month to find the monthly totals displayed in the table.

Q Do these results indicate that Rockport is a good deal for I&M's ratepayers?

A No, not necessarily. These results indicate that, based on the cost data provided by I&M, the plant is covering its base operational costs with a net positive margin. But this analysis says nothing about whether the plant is on net the lowest cost resource for ratepayers. I&M's purchased-power costs for its non-ownership share of Rockport through AEP Generating Company ("AEG")[14] were $75.35/MWh for 2019, while market power cost was only $31.83/MWh.[15]

If Rockport is making money relative to the market, as I&M's operational data shows it is, then the average cost of energy for Rockport must be less than the $31.83/MWh market cost of energy. This means that the remainder of the cost of purchased-power costs at Rockport must be attributed to the capacity cost of the plant. I estimate the capacity value of the 1,310 MW[16] portion of Rockport owned by AEG based on the PJM market capacity value in 2019 (see section IV.B. for a full discussion of capacity value) and find that I&M

[13] I&M Response to Staff 1-07, CONFIDENTIAL Attachment 1-07; and I&M Response to Staff 1-05, CONFIDENTIAL Attachment 1-05.

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

[15] Exhibit IM-3 (DHL-1), p. 3; and Ex SC-19 (MPSC Case No. U-20529, Staff Response to Sierra Club Request SC-1 and SC-2 Attachment).

[16] MPSC Case No. U-20529, Direct Testimony of Hazel A. Baker, p. 7.

customers are paying an estimated $22.42/MWh premium[17] 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 $63 million premium for Rockport services, approximately $44 million of which is allocated to I&M based on the Unit power sale agreement, and approximately $6 million of which is passed onto Michigan customers in this PSCR docket.[18]

Q Do you have any concerns with the unit commitment data I&M has provided?

A Yes, I am concerned about a large difference between marginal and booked fuel costs. Specifically, I&M's marginal fuel costs for the entire Rockport Plant are substantially lower than its fuel costs as implied by its fuel receipts and its fuel costs as reported to the Federal Energy Regulatory Commission ("FERC").

I am worried that I&M may not accurately and transparently account for all fuel costs in making its unit commitment decision. To be clear, I am not saying that any specific reported cost category is incorrect. In fact, it is reasonable that marginal and booked fuel costs will differ, as they represent slightly different costs. But I find it concerning that there is no clarity about why fuel costs, which should all represent roughly the same category of costs, vary substantially across accounting sources. These discrepancies critically impact both how economic a unit appears when evaluating its actual net revenue, and also the costs used for the purpose of making unit commitment decisions. I&M should provide

[17] Exhibit IM-3 (DLH-1); Monthly Staff PSCR Reports; PJM State of the Market Reports, May 2020, p. 91, available online at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020q1-som-pjm.pdf.

[18] I&M purchases 70% of AEG's share of each Rockport unit.

significantly more transparency on how it calculates and reports its fuel costs across sources.

Q What are marginal fuel costs and what marginal fuel costs did I&M report in 2019?

A For the purposes of unit commitment in Michigan, marginal fuel costs represent the replacement cost of fuel, i.e. what I&M would pay today to replace the coal that was burned. This marginal cost is set based on what the Company would pay in the spot market.[19]

I&M originally provided daily marginal variable cost "curves,"[20] which broke down fuel and variable O&M costs across different output levels from Rockport 1 and 2.[21] I&M stated that these values represent costs included in the market offer curves provided to PJM.[22] Rockport's total fuel cost based on this original data was [[[redacted]]] (and its total variable cost was [[[redacted]]]). In response to requests for I&M to provide its marginal costs at a higher level of granularity, I&M then provided hourly marginal variable costs (not broken out by fuel and variable O&M). In this second set of data, Rockport's total variable costs added up to of [[[redacted]]], approximately [[[redacted]]] of

[19] Order in MPSC Case No. U-17678-R. (p.19).

[20] I&M stated that these curves represent the difference in heat rates at different levels of output at each unit. The curves provided were linear, which does not accurately represent how heat rate changes with output.

[21] I&M Original Response to Sierra Club Request 1-01(i) and (g), CONFIDENTIAL Attachment SC 1-(i&g).

[22] I&M Response to Sierra Club Request 2-01 (a) and (b).

which can be attributed to fuel costs[23] (based on the ratio between fuel and variable O&M costs in the original dataset provided by I&M). It is unclear why there is such a large discrepancy between the "curves" used in I&M's *offers* into the PJM market (which dictate dispatch when the unit is committed as must-run and whether the plant operates or not when committed as economic) and the hourly marginal *cost* data the Company subsequently provided. For the calculations, I relied on the hourly marginal fuel costs because of the hourly granularity this data set provided and to be consistent with precedent as noted above.

Q What are accounting fuel costs, and what level of accounting fuel costs did I&M report in 2019?

A Accounting, or as-burned fuel costs, represents the cost of the coal in the company's inventory. When coal is procured under long-term contracts, the cost of coal for accounting purposes can be different than the marginal cost based on the difference in the cost of coal between when the contract was originally signed and today.

I&M would not provide the booked cost of coal burned but instead provided its monthly fuel receipts for Rockport. These fuel receipts represent the delivered cost of coal. Ideally, the quantity of coal the Company is purchasing should roughly match how much it is burning. While coal can be stored on site, there are costs implied in storing surplus coal; therefore, it is not desirable for a company's coal purchases to significantly exceed its coal burns. Based on its fuel receipts, we can see that the Company spent [[[redacted]]] on

[23] I&M Response to Sierra Club Request 1-01 (l,n,o), CONFIDENTIAL Attachment SC 1-1(l,n,o); I&M Response to Sierra Club Request 1-01(g), CONFIDENTIAL Attachment SC 1-0(g) CORRECTED.

coal in 2019, which implies a total variable cost of [[[redacted]]] using the same fuel to variable O&M ratio described above.[24]

Q What are fuel costs as reported to the FERC?

A I&M reported $229,242,429 in fuel costs to the FERC on Form 1 in 2019.[25] Fuel costs reported on Form 1 should represent the fuel portion of the unit's production cost, which should be based on the cost of fuel as burned. I&M declined to answer questions relating to the fuel costs its reports to FERC,[26] so it is unclear if the reported fuel costs in fact represent the as-burned cost of coal, how the costs were calculated, and why they are significantly higher than reported fuel receipts and marginal fuel costs used for the purpose of making unit commitment decisions.

Q How does this discrepancy in reported fuel costs impact your evaluation of the unit's economic performance?

A I calculated net revenues based on the Company's hourly marginal fuel costs (based on the prior MPSC order discussed above). In my analysis, plant revenues exceed variable costs and therefore the units appear on net to be economic. But, if the accounting fuel receipts (or the fuel costs as reported to the FERC) are used to evaluate unit performance, the net revenues decrease significantly, and the plant even begins to accumulate net losses. Critically, accounting fuel costs are what customers' actually pay.

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[24] I&M Response to Staff Request 1-01, Exhibit IM-1 Confidential Workpaper.

[25] FERC Form 1. Excerpt attached as Ex SC-2.

[26] I&M Response to Sierra Club Request 2-02 and 2-03.

Q How does this discrepancy in reported fuel costs impact the Company's unit commitment decision-making?

A When units are committed economically, unit commitment decisions are made by comparing variable production cost, including fuel and variable O&M costs, to day-ahead market prices. If market revenue is projected to be higher than operating costs, the unit will be committed. Lower operating costs therefore make it more likely that a unit will be committed. If the marginal fuel costs used for making unit commitment decisions represent only a portion of the actual cost of fuel,[27] then a unit will appear more economic than it would with actual full cost accounting. This means a unit will be over-committed and over-dispatched based on its artificially low marginal cost.

Full costs are still passed onto ratepayers, regardless of what cost is used to make unit commitment and dispatch decisions either through the PSCR process (for fuel costs) or rates (for the variable component). But those costs will be higher than they should be based on the plant being economically committed and operated more than it should. For this reason, the Commission should be concerned about lack of transparency around what fuel costs the Company is using for different purposes and how those costs are calculated.

[27] I&M Response to Staff Request 1-01, Exhibit IM-1 Confidential Workpaper.

C. OTHER STATE COMMISSIONS AND REGIONAL TRANSMISSION ORGANIZATIONS ("RTO") ARE CONCERNED ABOUT UNECONOMIC UNIT COMMITMENT PRACTICES

Q Have other state commissions and RTOs raised concerns about self-commitment in the wholesale markets?

A Yes. Numerous commissions around the country have begun to recognize the importance of this issue, with some considering unit commitment as part of existing dockets and others initiating separate dockets dedicated to evaluating unit commitment practices. These include the following:

- The Minnesota Public Utility Commission opened a docket titled *Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities* to review the unit commitment practices for Minnesota Power, Ottertail Power, and Xcel Energy. This docket is ongoing.[28]
- The Indiana Commission opened a subdocket earlier this year to evaluate the prudence of Duke Energy Indiana unit commitment practices after receiving evidence of uneconomic unit commitment practices in a Fuel Adjustment Clause proceeding.[29] This docket is ongoing.
- The Missouri Public Service Commission has a fuel prudence review docket that occurs every 18 months. In Missouri, this prudence review supplements quarterly Fuel Adjustment Clause (FAC) filings.[30]

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[28] Minnesota Public Utility Commission Docket No. E99/CI-19-704.

[29] Indiana Utility Regulatory Commission Cause No. 38707-FAC123 S1.

[30] Missouri Public Service Commission, Docket No. EW-2019-0370.

- The Southwest Power Pool market monitor published a report in December 2019 which found that nearly half of all megawatts (MW) generated between March 2014 and August 2019 were self-committed, and that this was impacting market prices and the efficiency of market operations.[31] In September of this year, SPP staff released a subsequent report evaluating the impact of self-commitment practices in SPP. Their analysis found that around 10 percent of self-committed generation would not have been chosen for commitment and dispatch on a least-cost basis.[32]
- MISO published a brief analysis earlier this year which found that 12 percent of generation came from uneconomically committed units.[33]

D. THE COMMISSION SHOULD REQUIRE I&M TO MAKE PRICE-BASED UNIT COMMITMENT DECISION

Q What is the scope of the reconciliation proceedings?

A The reconciliation proceedings cover the reasonableness of fuel costs incurred by the Company to provide electricity to ratepayers during the one-year period between January

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[31] Southwest Power Pool Market Monitoring Unit, *Self-committing in SPP markets: Overview, impacts, and recommendations*, Southwest Power Pool (Dec. 2019). An excerpt is sponsored as Ex SC-3. The entire version is available at: https://spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf.

[32] Ex SC-12. (Southwest Power Pool Staff, *Self-Commitment in SPP's Day-Ahead Market*, Southwest Power Pool (September 2020)). Also, available at: https://spp.org/documents/63092/2020%2009%2028%20commitments%20in%20spps%20integrated%20marketplace.pdf.

[33] Catherine Morehouse, *MISO: Majority of coal is self-committed, 12% was uneconomic over 3-year period*, Utility Dive (May 2020). An excerpt is sponsored as Ex SC-5. The entire version is available at https://www.utilitydive.com/news/miso-majority-of-coal-is-self-committed-12-was-uneconomic-over-3-year-pe/577508/.

1, 2019 and December 31, 2019. The reasonableness of fuel costs depends on the reasonableness of unit commitment decisions, among other factors.

Q What information specifically do you recommend that I&M provide in each reconciliation filing to allow a review of the prudence of its unit commitment practices?

A I recommend that I&M compile and be prepared to produce as workpapers in its reconciliation application all Profit and Loss Analysis sheets (in their native, e.g., Excel, spreadsheet file formats) prepared for each day that falls within the reconciliation period. Along with these sheets, I&M should provide a brief description memorializing the reason for any deviance between the results of the Company's forward-looking price-based analysis and the Company's actual commitment decision. In addition, I&M should provide hourly data sufficient for the Commission to calculate the net revenues that each plant actually incurred in each reconciliation period including total unit generation, accounting "as burned" fuel cost, marginal or "replacement" fuel cost, total variable operations and maintenance ("O&M") cost, unit locational marginal price ("LMP"), day-ahead commitment status, energy and ancillary market revenues, and actual outages.

Q What are your recommendations regarding the Commission's assessment of Company commitment practices?

A The Commission should disallow recovery of losses incurred at Rockport as part of I&M's PSCR process if I&M does not follow market price signals, or the results of its own price-based process, and thereby fails to generate or purchase power at the lowest reasonable cost.

Q Are you recommending a disallowance in this docket relating to I&M uneconomic commit practices at Rockport?

A Yes, based on my review of the Company's unit commitment decision-making analysis, and the actual unit performance, I am recommending a disallowance of [[[redacted]]], which represents Michigan's share of the [[[redacted]]] in fuel costs I&M imprudently incurred. This represents just the fuel portion of the total [[[redacted]]] in variable costs incurred at Rockport unnecessarily (net of start-up costs) during the events I identified in Section III.A above, where the Company imprudently decided to keep a unit online despite its own projections indicating that the unit was very likely to lose money over that period. This disallowance was calculated based on marginal fuel costs, not as-burned fuel costs, and uses a Michigan jurisdictional allocation factor of 13.94 percent based on Michigan's share of total company fuel and purchased power expenses from U-20359.[34]

IV. I&M CUSTOMERS ARE PAYING ABOVE-MARKET PRICE FOR OVEC POWER

Q Please summarize this section.

A In this section I summarize the details of I&M's purchase of power from OVEC and I&M's status as a co-owner of the power plants owned and operated by OVEC. I explain how I&M, combined with other American Electric Power ("AEP") affiliates, has a 43.47 percent participation interest in OVEC and receives power from the OVEC units through the ICPA. I discuss how I&M has never sought or received approval for the ICPA, despite passing all contract costs onto ratepayers. I provide evidence that OVEC is in fact an

[34] Ex SC-13 (MPSC Case No. U-20359, Exhibit No. A-3, Schedule C-1, p. 1 of 1).

affiliate of I&M and is paying above-market prices for power. I discuss how arguments about the reasonableness of the OVEC contract based on comparison to any other non-affiliate contract are irrelevant. I quantify the additional costs being passed on to Michigan ratepayers based on the difference between OVEC's energy and demand charges, and PJM's energy and capacity market prices. Finally, I recommend that the Commission disallow I&M's recovery of costs for the Michigan jurisdictional share of compensation for the ICPA that are in excess of the 2019 equivalent market costs for those products and services.

A. I&M PURCHASES POWER FROM OVEC, AN AFFILIATE COMPANY, AT ABOVE-MARKET PRICES AND PASSES THE COSTS ON TO RATEPAYERS.

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 coal-fired power plants—Kyger Creek in Gallia County, Ohio, and Clifty Creek in Jefferson County, Indiana—and supplies the power from these plants to the utilities through a long-term contract called the ICPA.[35] The utilities together are responsible for the fixed and variable costs of OVEC, and OVEC in turn charges the utilities a variable, demand, and transmission cost.

I&M's share of the ICPA with OVEC is 7.85 percent.[36] 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")

[35] Ex SC-5 (Ohio Valley Electric Corporation, Annual Report - 2019, p. 1).

[36] Ex SC-14 (I&M Response to Sierra Club Request 3-11 with SC 3-11 Attachment 1).

share of 174–174.3 MW in 2019.[37] The cost of the ICPA is passed through to I&M ratepayers as a direct cost. In 2019, I&M was billed $51,524,987 by OVEC.[38] OVEC charges variable, demand, and transmission charges.[39]

Q Has I&M ever sought or received approval from the Commission to extend its participation in the ICPA?

A No. Previously, the ICPA was set to expire on December 31, 2005. Before this date, the Sponsors agreed among themselves to extend the ICPA to 2026.[40] I&M did not seek approval for the contract at the time the contract was extended in 2004.

In September 2010, the Sponsors again agreed to an extension of the ICPA until 2040. I&M and the other participating IOUs are therefore obligated to cover the costs of the OVEC plants through 2040. The two OVEC coal plants will each be 85 years old by the time the ICPA expires.[41] Once again, I&M did not request or receive Commission approval to include the amended ICPA in rates. Other utilities, including I&M's affiliate Appalachian Power, did seek approval for rate recovery in other states.[42]

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[37] Ex SC-10 (I&M Response to SC Request 3-04).

[38] Ex SC-7 (I&M Response to SC 3-02 and SC 3-02 Attachment 1).

[39] Ex SC-14.

[40] Ex SC-5.

[41] *Id.*

[42] MPSC Case No. U-20529, Direct Testimony of J. Fisher, PhD, May 11, 2020, p. 42. Excerpt included as Ex SC-6.

Q What else should we know about 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 39.17 percent equity stake in OVEC.[43]

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 and OVEC include:[44]

6. 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.
7. 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 Finance and Corporate Experience and witness in I&M's 2019 rate case, also serves on the Board of Directors for IKEC.

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[43] Ex SC-5.

[44] Ex SC-5; Ex SC-15 (AEP Leadership Biography of Paul Chodak III), also, available online at: https://www.aep.com/about/leadership/chodak; and Ex SC-20 ("Credit Opinion: Ohio Valley Electric Cooperative," *Moody's Investors Service*, December 2018.)

8. 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:[45]

9. OVEC holds a long-standing service agreement with AEP Service Corporation ("AEPSC") under which AEP administers and negotiates the terms of existing and proposed fuel contracts for OVEC.
10. 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.

The ICPA is not just a regular power purchase agreement in which I&M is a minor participant. 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.

[45] Ex SC-16 (MPSC Case No. U-20529, I&M's Response to Sierra Club Request SC 1-20); and Ex SC-17 (MPSC Case No. U-20529 Exhibit SC-9 (OVEC Board Meeting Notes from Dec. 1, 2015 and Dec. 8, 2017)).

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 would characterize OVEC as an affiliate of I&M. The Code of Conduct disallows utilities from acquiring from affiliates "products or services" in excess of the "market price." [46] As we will discuss, 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 I&M and OVEC are affiliates by virtue of being "under common control."[47] AEP is both a parent company to I&M and the single-largest participating interest in OVEC. In total, AEP has a 39.17 percent equity stake and a 43.47 percent participation interest in OVEC via subsidiary holdings—far above the 7 percent ownership level that the Code of Conduct defines as "control."[48] 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 we will now discuss, OVEC is billing substantially above market prices, which suggests that the transaction does not comply with the Code of Conduct.

[46] MPSC Code of Conduct, R460.10102 and R R460.10108.

[47] MPSC Code of Conduct, R460.10102 and R R460.10108.

[48] Ex SC-5.

Q What evidence do you have that I&M is paying above-market prices for power under the ICPA?

A I compared the total cost billed to members of the ICPA, including energy, demand (capacity), and transmission charges, on one hand; and the value of the energy, capacity, and ancillary services provided by OVEC if sold into the PJM market, on the other. If I&M is paying a higher price for the energy and capacity received under the ICPA than it would pay to purchase equivalent market energy and capacity from PJM, then it is getting a bad deal for ratepayers.

I&M's own data shows that in 2019 OVEC billed I&M $51,524,987 for 925,846 MWh of electricity. [49] That works out to $55.59/MWh. 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 $35.80/MWh for I&M.[50] This is well below the cost OVEC is charging I&M and much closer to the average cost of I&M purchases from PJM in 2019 at $31.83/MWh.[51]

That amounts to a net loss of $18,308,559 that 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 every month

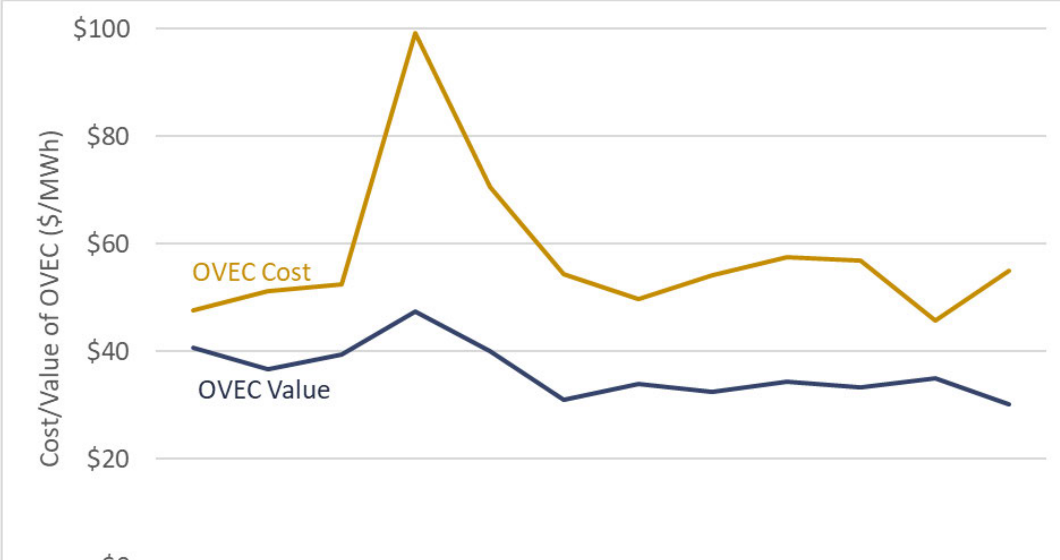
[49] Ex SC-7.

[50] Exs SC-8, SC-9, SC-10; and PJM State of the Market Report, May 2020, p. 81, available online at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020q1-som-pjm.pdf, excerpt attached as Ex SC-18.

[51] Exhibit IM-3 (DHL-1), p.3. The cost of OVEC purchased power is $56.42/MWh on the exhibits – this differs slightly from the cost we calculated based on OVEC billing statements.

of 2019, 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 (2019)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
OVEC Cost	$47.75	$51.19	$52.51	$99.18	$70.67	$54.46	$49.71	$54.09	$57.56	$56.84	$45.74	$54.98
OVEC Value	$40.7	$36.6	$39.5	$47.4	$40.0	$30.9	$33.9	$32.5	$34.4	$33.4	$35.0	$30.2

Source: *Exs SC-8, SC-9, SC-10, and SC-18.*

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

A I&M provided the monthly billing from OVEC for January–December 2019 which includes MWh sold, energy, demand, and transmission charges, along with PJM Expenses and Fees.[52] The Company provided energy revenue by month from 2019,[53] and we have ancillary service revenue for 2019 from a prior docket (U-20529).[54]

[52] Ex SC-7.

[53] Ex SC-8.

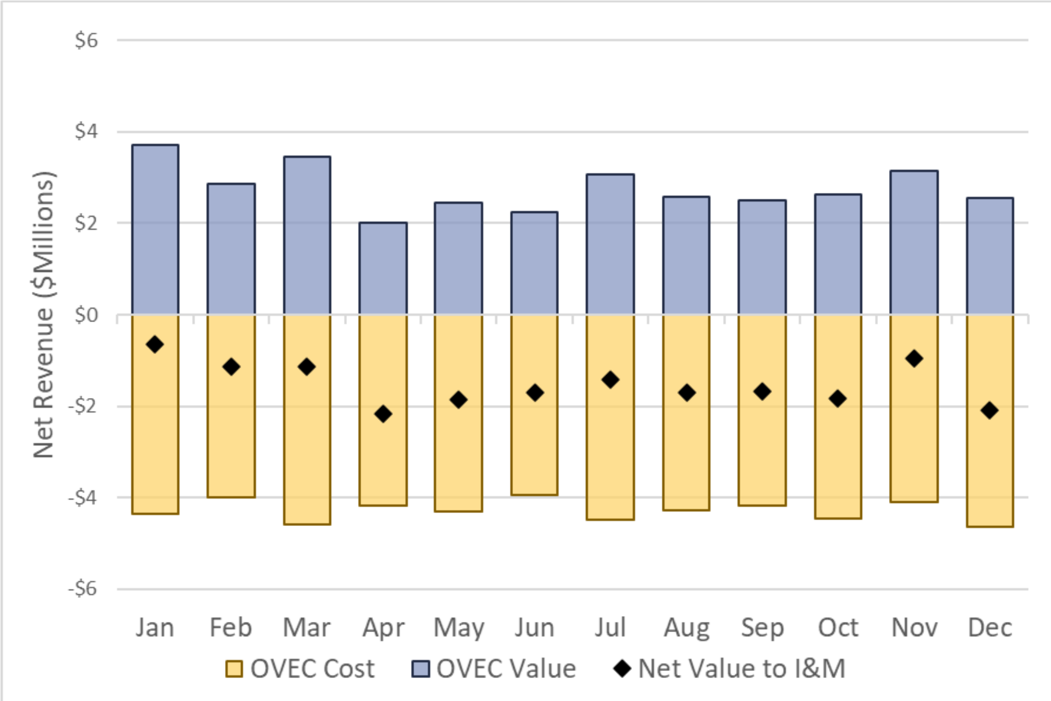
[54] Ex SC-9.

The Company also provided the installed capacity ("ICAP") associated with its share of OVEC by month (174 MW in January–May, and 174.3 MW June–December).[55] I&M refused to provide a capacity value or any equivalent for the sale of capacity on the basis that I&M has a Fixed Resource Requirement ("FRR") designation and therefore does not participate in the PJM capacity market. Therefore, I estimated a 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, and the value of the ICPA would be equal to the energy, ancillary service value plus the capacity value as if OVEC's capacity was sold under PJM's Base Residual Auction. Figure 2 below shows the monthly OVEC billing versus I&M revenue from ICPA energy, ancillary services, and capacity for 2019. 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.

[55] Ex SC-10.

Figure 2: OVEC billing versus I&M revenue from ICPA energy, ancillary services, and capacity (2019)



Source: *Exs SC-8, SC-9, SC-10, and SC-18.*

Q Why is it reasonable to use PJM's capacity value as a proxy for the value of OVEC's capacity?

A AEP, I&M's parent company, has elected to take an FRR designation in PJM and therefore does not participate in the capacity market. For this reason, I&M states that "comparison to any other capacity price isn't going to be valid."[56] But this logic is flawed. The PJM capacity market represents the price that other actors are willing to pay for capacity, and if I&M or any other AEP entity wanted to acquire capacity, they would look to the PJM capacity market as a benchmark. Additionally, I&M used PJM's forecasted capacity market prices as a fundamental parameter of its 2018–2019 Integrated Resource Plan, and

[56] I&M Response to Sierra Club Request 1-20.

the Company priced short-term market purchase of capacity based on PJM capacity pricing.[57]

Additionally, I&M argument about the FRR raises an important question of whether the FRR construct as an alternative to the PJM capacity market (as applied by AEP) is in the best interest of customers if it allows the application of an extremely high capacity price to justify an above-market contract at the expense of ratepayers at the same time the utility itself is long on capacity.

Q Can we compare the ICPA to other long-term contracts that I&M has signed to evaluate the reasonableness of the contract's cost?

A No. All contracts contain a degree of risk in exchange for hedging against a potentially larger future risk. Engaging in contracts is part of doing business for utilities. I am not suggesting that I&M should never be allowed to engage in long-term contracts. Based on the relationship between I&M and OVEC, I am concerned that the ICPA is not an arms-length contract. With normal contracts, when the Company is wrong, the ratepayers may pay more but the utility does not also benefit at the expense of the customer. With the ICPA, because I&M's parent company also has a significant equity share in OVEC (i.e., the contractual counterparty), it has an interest in both sides of the contract. Ratepayers still bear the risk of prices dropping significantly below those in the long-term contract, but I&M's parent company will benefit regardless of what happens to prices.

[57] "I&M 2018-2019 Integrated Resource Plan," Indiana Michigan Power Company, Jul. 1, 2019, p. 102. Excerpt included as Ex SC-11.

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

A I&M's own data shows that OVEC services cost more than market equivalent services in 2019. Specifically, the ICPA has cost I&M customers $18.3 million more than the market price for the same amount of energy and capacity in 2019. Further, based on public analysis performed by experts in other dockets,[58] it is likely that the ICPA will continue to be higher cost than market-equivalent product and services, and therefore will continue to be costly for I&M ratepayers.

B. THE COMMISSION SHOULD CAP I&M'S RECOVERY OF THE MICHIGAN JURISDICTIONAL SHARE OF COMPENSATION FOR THE ICPA

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 disallow in PSCR dockets recovery of costs paid under the ICPA in excess of the cost of equivalent market services, as determined by the value of energy, ancillary services, and market prices for capacity as delivered at OVEC's zone.

Q Are you recommending a specific disallowance in this docket relating to I&M OVEC purchases?

A Yes, I recommend that the Commission disallow I&M's recovery of $2,557,952. This represents Michigan's jurisdictional share of the total $18,343,791 in excess compensation that I&M paid for OVEC services under the ICPA (relative to the market value of the services).

[58] MPSC Case No. U-20529, Public Direct Testimony of J. Fisher, PhD.

Q Does this conclude your testimony?

A Yes.

Synapse
Energy Economics, Inc.

Devi Glick, Senior Associate

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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.

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Resume updated September 2020

THIS FILING IS		
Item 1: ☐ An Initial (Original) Submission	OR ☒	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Indiana Michigan Power Company	**End of** 2019/Q4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/28/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *ROCKPORT TOTAL I&M* (d)	Plant Name: *ROCKPORT TOTAL PLANT* (e)	Plant Name: *Donald C Cook Plant* (f)	Line No.
Steam	Steam	Nuclear	1
Conventional	Conventional	Conventional	2
1984	1984	1975	3
1989	1989	1978	4
1310.00	2620.00	2285.00	5
1316	2631	2323	6
6548	6548	8760	7
0	0	0	8
1310	2620	2288	9
1309	2619	2154	10
0	227	1090	11
4073384000	8146768000	16157849000	12
6545277	13061228	1879588	13
105820773	213387605	433270558	14
984769775	1959580508	2982278860	15
14835424	29652773	439029649	16
1111971249	2215682114	3856458655	17
848.8330	845.6802	1687.7281	18
5379573	10674202	19599303	19
114621365	229242429	93313724	20
0	0	7693078	21
12351935	24152389	12734104	22
0	0	0	23
0	0	0	24
1640756	3281522	5145042	25
1818828	9562780	68901407	26
69204233	136544231	0	27
861468	861468	0	28
2742440	5480358	8732251	29
1088729	2177471	3461933	30
7551409	15117323	87642414	31
2243895	4490644	17102044	32
1034498	2069491	17362876	33
220539129	443654308	341688176	34
0.0541	0.0545	0.0211	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Oil		Coal	Oil		Nuclear			36
Tons	Barrels		Tons	Barrels					37
2296267	24544	0	4592533	49087	0	0	0	0	38
8897	132077	0	8897	132077	0	0	0	0	39
47.937	81.964	0.000	47.855	81.964	0.000	0.000	0.000	0.000	40
49.038	82.412	0.000	49.040	82.412	0.000	0.000	0.000	0.000	41
2.756	14.856	0.000	2.756	14.856	0.000	0.560	0.000	0.000	42
0.025	0.000	0.000	0.028	0.000	0.000	0.006	0.000	0.000	43
10069.000	0.000	0.000	10069.000	0.000	0.000	10316.000	0.000	0.000	44

SPP Southwest Power Pool
MARKET MONITORING UNIT

Self-committing in SPP markets: Overview, impacts, and recommendations

Published December 2019

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1 OVERVIEW AND RECOMMENDATIONS

In this report, we examine self-commitment offer behavior in SPP's Integrated Marketplace, and describe how self-commitment can affect market participants and market outcomes.

Towards that end, we conducted an empirical study analyzing offer behavior over the period of March 2014 to August 2019, and ran two simulation series of a week per month from September 2018 to August 2019 where we re-solved past market cases. The simulations included the following assumptions: (1) all generation is offered in market status, and (2) all generation offered in market status can be started economically by the day-ahead market.

Key takeaways from our analysis include:

- The volume of self-committed megawatts has declined over time, but remains nearly half of the total megawatt volume generated from March 2014 through August 2019.
- Prices and production costs were systematically lower when at least one self-committed unit was marginal.
- In almost all cases, self-committed generators had lower revenues because of negative congestion prices; whereas, market-committed generators typically had a more balanced congestion profile.
- Resources with long lead times and/or high start-up costs tend to be self-committed instead of market-committed.
- Units that are self-committed generally have much higher capacity factors than those that are market-committed. However, these results differ substantially by fuel type.

Key takeaways from the simulations include:

- When the market made unit commitment decisions, and lead times remained unchanged, both market-wide production costs and market clearing prices for energy increased.

- When the market made unit commitment decisions and lead times were modified to allow the day-ahead market to commit the resources with long lead times, market-wide production costs were essentially unchanged and market clearing prices for energy increased.
    - System prices increased by about $2/MWh (seven percent) on average.
    - Congestion prices changed by about –$1/MWh to $1/MWh on average.
- To optimize long-lead time resources' participation in the market, the economic commitment process would need to solve over a longer market window (e.g., over a two-day period rather than just one day).

1.1 RECOMMENDATIONS

- In order to improve price formation and market efficiency, we recommend SPP and stakeholders work to reduce the incidence of self-commitments.
- We recommend modifying SPP's market design by adding one additional day to the market optimization period.[1]

1.2 OUTLINE

The paper is organized as follows. In chapter 2, we cover the mechanics of self-commitment in the SPP market, how this impacts the supply curve, and identify reasons participants may choose to self-commit their generation. Chapter 3 covers the theoretical underpinnings of the market and efficient price formation. Chapter 4 presents empirical observations over the study period comparing market and self-commitment behavior. Chapter 5 covers self-commitment behavior and price formation. Chapter 6 presents two simulation scenarios estimating how market results

[1] SPP has found in its multi-day forecasting study, the accuracy of forecasts (load and wind) remain at acceptable levels for a second day but decline sharply afterwards.

would change if participants market-committed versus self-committed. Chapter 7 highlights our conclusions.

The empirical study period spans from March 2014 through August 2019 and covers all resources and fuel types. However, in our presentation of offer and generation related metrics, we exclude nuclear resources because of the limited number of resources with this fuel type.[2]

Readers of this report may note that the analysis of self-commitment differs from what we have presented in our previous reports. In our annual and quarterly state of the markets reports, we have presented self-commitment information in the form of offers and unit starts. In this report, we focus instead on the megawatts produced from self-committed units.

The re-run (simulations) study period covers the first week of each month from September 2018 through August 2019.[3] We believe that this provides a significant enough sample of re-runs to capture seasonality in the market.

[2] Many of the charts and analysis that follows presents offer behavior by fuel type. As there are a limited number of nuclear resources, any charts that show this as a fuel type could potentially expose specific market offer data. All other resources have a sufficient number of resources to mask any specific offer behavior.

[3] Additional information regarding the sample set can be found in chapter 6.

2 SELF-COMMITMENT MECHANICS

In the broadest terms, and similar to other auction-based electricity markets, the Integrated Marketplace attempts to minimize the cost to serve load[4] subject to transmission and generator constraints. The day-ahead market does this by using two main tools: centralized unit commitment[5] and economic dispatch.[6]

Centralized unit commitment sorts the available generators from least expensive to most expensive and then selects the least expensive units that can achieve the objective without violating the constraints of the optimization.

Economic dispatch then uses the results of the unit commitment process as inputs to its own separate optimization. The results of which produce two key, time-based outputs: the megawatts each generator should produce at the corresponding locational prices.

Centralized unit commitment and economic dispatch processes are designed to work together to make the market more efficient. For instance, FERC stated that "…the unit commitment process an essential part of least-cost operation" when discussing price formation in organized wholesale electricity markets.[7]

The idea behind centralized unit commitment is essentially this: In the same way a team will likely realize better outcomes when the coach selects both the players and plays, the Integrated

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[4] The cost to serve load is also referred to as production cost.

[5] The Integrated Marketplace Protocols define Security Constrained Unit Commitment as an algorithm capable of committing Resources to supply Energy and/or Operating Reserve on a co-optimized basis that minimizes commitment costs while enforcing multiple security constraints. Integrated Marketplace Protocols, Section 1 Glossary

[6] The Integrated Marketplace Protocols define Security Constrained Economic Dispatch as an algorithm capable of clearing, dispatching, and pricing Energy and Operating Reserve on a co-optimized basis that minimizes overall cost while enforcing multiple security constraints. Integrated Marketplace Protocols, Section 1 Glossary

[7] Price Formation in Organized Wholesale Electricity Markets, Docket No. AD14-14-000

Marketplace will also probably realize better outcomes, for the collective, when it commits units in addition to dispatching them. While the team's record might be the same regardless of who is on the field, it is unlikely that the plays called, points scored, or yards gained would be the same.

Much like players choosing when to play, the SPP market allows participants to self-commit resources rather than have the market choose which units to run. While there may be good reasons for this (see Section 2.2 below), the practice can distort prices and investment signals.

2.1 TYPES OF COMMITMENT STATUS

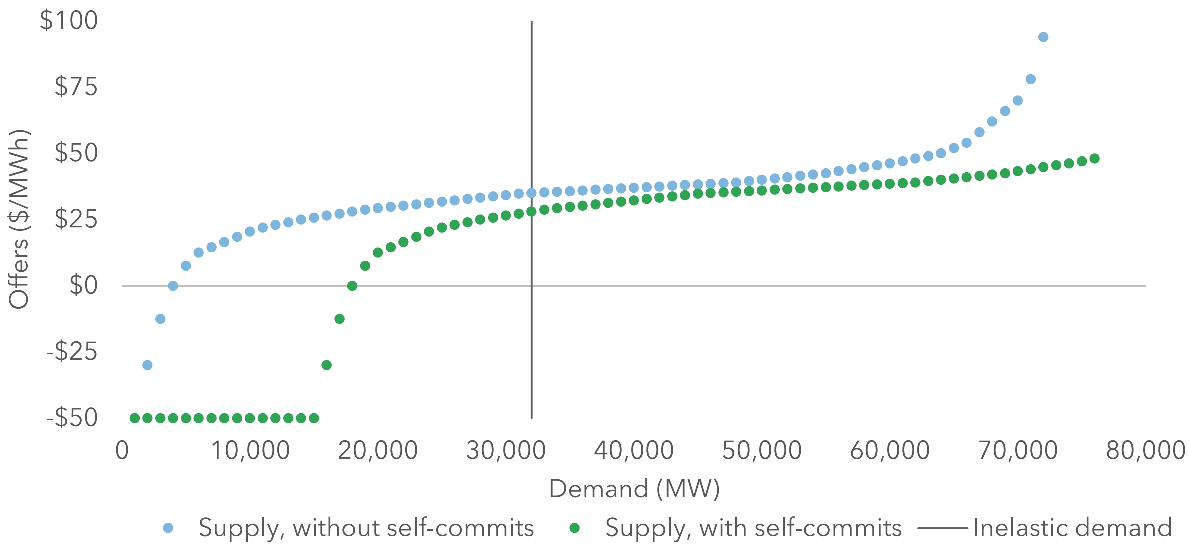
Including self-commitment, the Integrated Marketplace permits five different commitment statuses. The statuses convey information to the centralized unit commitment process. Each status and its accompanying description can be found below:

1. Market – the resource is available for centralized unit commitment through its price sensitive (merit-based) price quantity offers.
2. Self – the market participant is committing the resource through price insensitive offers outside of centralized unit commitment.
3. Reliability – the resource is off-line and is only available for centralized unit commitment if there is an anticipated reliability issue.
4. Outage – the resource is unavailable due to a planned, forced, maintenance, or other approved outage.
5. Not participating – the resource is otherwise available but has elected not to participate in the day-ahead market.

Because the day-ahead market cannot dispatch resources with commitment statuses of outage and not participating, we included market, self, and reliability commitment statuses in our empirical study. However, due to the extremely low megawatt volumes[8] dispatched from reliability-committed units, we present and discuss only market and self statuses in the report.

Mechanically, self-commitment can affect the construction of supply curves by altering the generators selected to serve the demand. Self-commitment shifts the merit order of the supply curve by treating the self-committed generators as price insensitive, which shifts the supply curve to the right.[9] This relationship is shown in Figure 2–1.

Figure 2–1 Rightward shift in market supply curve



The blue supply curve represents supply without self-committed megawatts, whereas the green supply curve represents supply including self-committed megawatts. When participants self-commit resources, the commitment algorithm does not make the decision to commit those units based on their cost. Participants make their own commitment decisions without regard to the optimization of total costs. Said another way, these resources effectively move themselves to the bottom of the cost curve. The result of a rightward shift in supply, all else equal, likely

[8] Over the study period, less than 0.004 percent of dispatched megawatts sourced from units committed in reliability status.

[9] Moreover, the supply curve itself can be reordered as resources whose commitment costs are high can also change the order of dispatch of incremental energy.

reduces the market's marginal clearing price.[10] In addition to shifting the supply curve to the right, the slope of the supply curve also changes when generators self-commit. The change in slope reflects the re-ordering of suppliers in least cost merit order for market dispatch based on the set of resources from the commitment process.[11]

Along with shifting and reordering the supply curve, when participants self-commit resources, their economic minimums essentially create a resource specific dispatch megawatt floor. These floors in turn, create additional constraints to which the economic dispatch optimization must solve around. Self-committed resources also carry the lowest curtailment priority, which means they are generally the last producers instructed to reduce output.[12] Because these self-committed units are deemed "must run", the dispatch engine cannot take them off-line for economic reasons.[13]

2.2 REASONS FOR SELF-COMMITMENT

We have worked with market participants to understand the reasons that participants self-commit generators. Market participants have stated the following reasons for self-commitment:

- Testing – NERC requirement
- Public Utilities Regulatory Policy Act (PURPA)
- Federal service exemptions
- Started by a different market
- Weather
- Long lead times

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[10] This is also known as the system marginal price.

[11] Under certain circumstances, this type of reordering could cause a price increase, but this has not been observed. Typically, the reordering has resulted in price declines.

[12] Integrated Marketplace Protocols, Section 4.3.2.2 Day-Ahead RUC Execution

[13] Integrated Marketplace Protocols, Section 4.4.2.5 Out-of-Merit Energy (OOME) Dispatch

- Fuel contracts
- Other contracts
- Long minimum run times
- Commitment bridging
- Desire to reduce thermal damage to the unit due to starts and stops
- High startup costs

Some of these reasons are unavoidable and can require the resource to be offered in self-status. Testing the output of a plant, as periodically required by regulatory agencies, is a frequent justification. A few generators in SPP are classified as qualifying facilities under the Public Utilities Regulatory Policy Act, and the commitment of those resources cannot be separated from other uses, such as cogeneration processes. Additionally, a small group of SPP resources qualifies for Federal service exemptions. Finally, a participant may need to self-commit a resource during very cold weather for reliability reasons.

Some of the reasons, such as high start-up costs, fuel contracts, or commitment bridging are economic in nature and can be handled within the market offer through dollar-based offer parameters. Thermal damage due to start-ups and shut-downs and resulting major maintenance could be included in mitigated offers starting in April 2019.[14] As we show later in the report, we have seen a general decline in self-committed generation over time and it is possible that perceptions of economic justifications have changed over time.

To the extent that a long lead time[15] is reflective of operating or environmental limitations, there may be a software limitation. To the extent that there are limitations to the software, these can be addressed through market design changes.

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[14] Revision Request 245.

[15] Based on August 2019 offers, 7 percent of resources (or MWs) had lead times longer than 32 hours and 10 percent had between 24 and 32 hours.

3 MARKET FEEDBACK LOOP

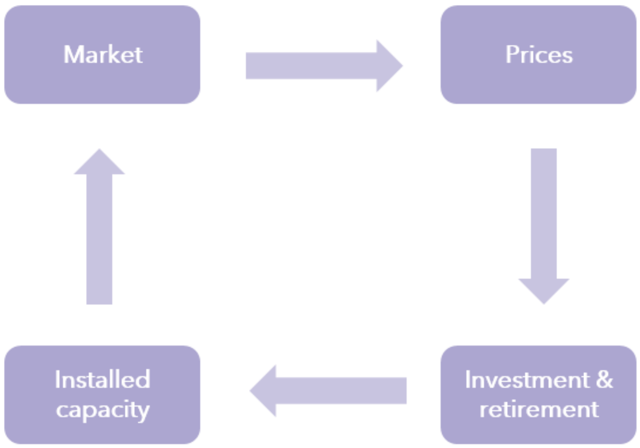
As we showed in the previous section, self-commitment of generation can put downward pressure on the marginal clearing price of energy. In this section, we discuss how the marginal clearing price drives the market feedback loop to bring about equilibrium and efficiency.

A central theory in economics is that competition leads to efficiency.[16] If the market design effectively fosters competition, a competitive equilibrium is possible, and by extension, efficiency may be gained. In electricity markets, a primary source of efficiency gain stems from the minimization of system production cost through centralized clearing. When this occurs, resulting prices are based on marginal costs and the level of production and consumption is optimal – the result is an efficient market at competitive equilibrium.

Market equilibrium generally has two time dimensions: the short-run and the long-run. In the short-run, market participants profit maximize by asking themselves, "What is the best we can do with our current set of resources?" They submit their best answers in the form of market offers. The market provides feedback in the form of commitment, dispatch, and prices. Market participants then use this information to adjust their short-run profit maximizing behavior. Concurrently, participants ask themselves, "What is the best we could do if we had something different?" This question relates to long-run market equilibrium and decision-making to include investment (or retirement) in installed capacity. The search for short-run and long-run equilibriums creates the market feedback loop. In the following sections, we will examine how self-commitment can affect this process and, by extension, market efficiency.

[16] Perfectly competitive markets attain both *productive efficiency*—where output is produced at the least possible cost—and *allocative efficiency*—where output produced is the one that consumers value most.

Figure 3–1 The market feedback loop



3.1 THE MARKET

For competition to flourish, several conditions must exist including having the lack of market power by market participants,[17] the necessary cost information,[18] and non-convex operating costs.[19] Good market design, along with effective regulation and monitoring, helps bring about the first two requirements. The third requirement, however, is unlike the first two. Convexity or lack thereof, is inherent to the characteristics of the resources that participate in the market. Non-convex costs occur when it is cheaper to produce two units than to produce one. Generator start-up and no-load operating costs have this property and are non-convex. As such, when non-convex cost elements exist, designing a competitive market with an efficient pricing mechanism is difficult. However, when suppliers lack market power and have necessary cost information, the improved, if not perfect, level of competition can still bring about efficiency improvements.

[17] A lack of market power implies being a price taker.

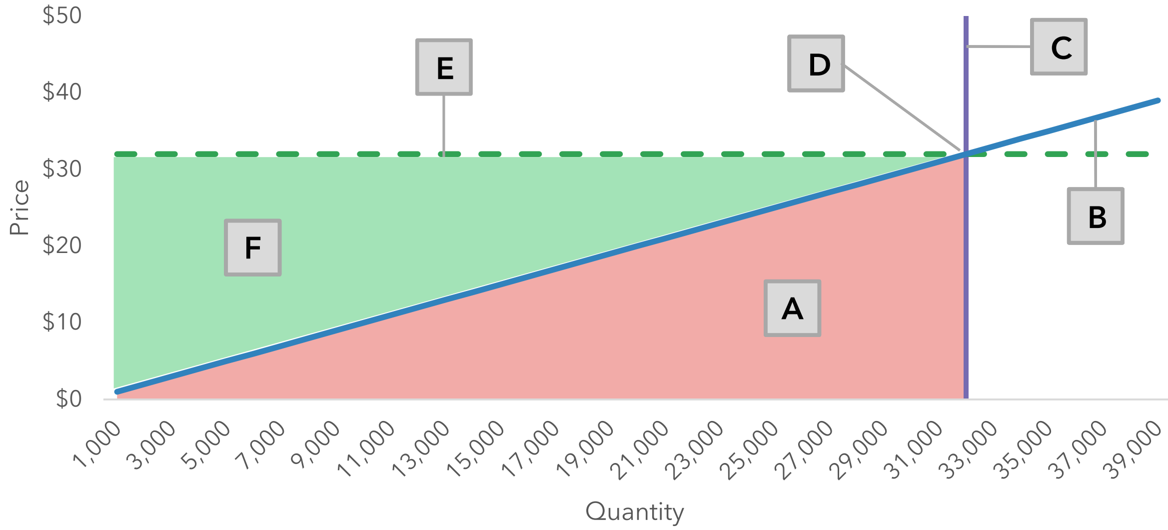
[18] All production costs are known.

[19] The shape of the cost curve is a critical input to the supply function. Classical economics assumes that costs are convex. In practice, some costs are nonconvex.

3.2 LINKING THE MARKET TO PRICES

Economics has concepts that are very precise and have specific meanings. For example, accountants and economists both use the term profit. However, the idea each intends to convey can differ materially.[20] For this reason, we provide the following simplified figure[21] and associated terms to help convey the appropriate intention.

Figure 3–2 Market supply and demand



A. The red shaded region is the production cost,[22] more specifically the energy portion of total production cost.[23] This region is also referred to as the area under the supply (or marginal cost) curve, which gives *total* variable cost, or *total* marginal cost.

B. The supply curve is the blue line. In electricity markets, the supply curve is created by summing the offers of market participants. These offers are submitted in price/quantity

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[20] For instance, the IRS expects income tax even when economic profit is zero.

[21] In order to facilitate illustration we use a linearized approximation (of a stepwise line) under a continuous function assumption.

[22] Corresponding to "mitigated offers" in SPP tariff terms.

[23] Production cost is generally presented as the sum of energy, start-up, no-load, and ancillary service costs.

pairs each indicating minimum price levels the supplier is willing to offer for the corresponding quantity. The price the supplier wants to be paid is plotted on the y-axis, and the quantity the supplier is willing to produce for that price is plotted on the x-axis.

C. The demand curve is the purple vertical line.[24] The demand curve shows price/quantity pairs each indicating maximum price levels the consumer is willing to demand for the corresponding quantity. Electricity is mostly a non-storable product and must be supplied instantly upon demand. Further, when there is no competition at the retail end, price elasticity is very low. As such, we represent demand as a vertical line.

D. The market-clearing price is the point where the supply meets the demand. When this occurs, all buyer orders have been filled and the market is said to have cleared. In an organized wholesale electricity market setting, the market clearing price is also called the spot price.

E. The dark green dotted line reflects the price each supplier is paid and is equivalent to the market-clearing price. This equilibrium price multiplied by the total quantity produced is the revenue received by all suppliers.

F. The light green shaded region is the producer surplus. Generally, when economists refer to profit, they are referring to the producer surplus. Short-run profits for individual producers can be calculated by subtracting variable costs from revenue where revenue equals market clearing price multiplied by the quantity produced.[25]

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[24] This represents perfectly inelastic demand. Under that assumption, demand is not responsive to price. In practice, the line may not be vertical, having a certain degree of downward slope depending on the degree of price responsiveness in the market, particularly in the day-ahead market.

[25] In electricity markets, start-up and no load costs, in addition to incremental energy costs, need to be included in the short-run profit calculation.

3.3 PRODUCTION COST MINIMIZED, NOT PRICE

The objective function of the market clearing software, stated generally, is to minimize production cost, not the marginal clearing price.[26] Broadly, production cost is the sum of energy,[27] ancillary services,[28] start-up,[29] and no-load[30] costs. Efficiency occurs by serving the same level of demand, while at the same time minimizing the sum of these costs. The clearing price is an output of the optimization and a component of the total production cost. Because the clearing price only relates to a component of the production cost (i.e., the incremental energy component), there is no guarantee that an increase in energy prices will translate to an increase in total production cost.

3.4 PRICE TO INVESTMENT SIGNALS

In the long run producers are incented to invest in projects that minimize their costs.[31] When current prices reflect the true marginal cost of the current set of producers at the margin, participants can better determine the cost structure of the market. When participants have better information, they will likely better optimize their existing generation portfolio. However, in the long run some market participants may not be able to use their existing fleet to achieve their desired level of profitability or recover their cost of capital. When participants find themselves in this situation, they consider entry and exit decisions. Typically, this means

[26] In this cost minimization problem, prices are discovered by identifying the marginal cost of serving the next increment of load during a specific interval and location.

[27] Energy is a power flow for a time period.

[28] Ancillary services are needed to maintain reliability of the system, often by forgoing the opportunity to sell energy.

[29] Start-up is the cost associated with preparing a generator to produce (and stop producing) energy or ancillary services.

[30] No-load is the theoretical cost of running a generator while producing no output.

[31] In a competitive market, the market price is given to individual suppliers and all they can do is to adjust their production amount that minimizes cost.

generators whose long run costs exceed projected revenues retire.[32] Then suppliers either permanently exit the market, focus on reducing maintenance costs, place the unit in reserve shutdown (i.e., mothball),[33] or invest in new lower cost generators.

3.5 INVESTMENT SIGNALS TO INSTALLED CAPACITY

Spot prices are an input to forward price projections and bilateral contract prices. Therefore, a spot price that does not reflect the true cost structure of the market can send an incorrect entry and exit signal. In addition to potentially sending distorted investment signals, generators that self-commit may displace other generators who would have otherwise been committed and earned energy market revenue. This could cause generators that should have earned profits to mount losses. These losses may subsequently incent more generators to self-commit, or cause a generator to retire who would have otherwise been profitable—either case results in a distorted investment signal. In short, sending the right price signal is critical, but so too is ensuring those who warrant the revenue—receive it.

[32] Projected revenues would be based on estimated forward prices.

[33] Mothballed generators are not used to produce electricity currently but could produce electricity in the future. Additionally, generators can be made available for reliability only.

4 UNIT COMMITMENT AND DISPATCH PROCESSES: EMPIRICAL FINDINGS

This section includes information and analysis regarding the pervasiveness of self-commitment, and then discusses generator start-up parameters and capacity factors.

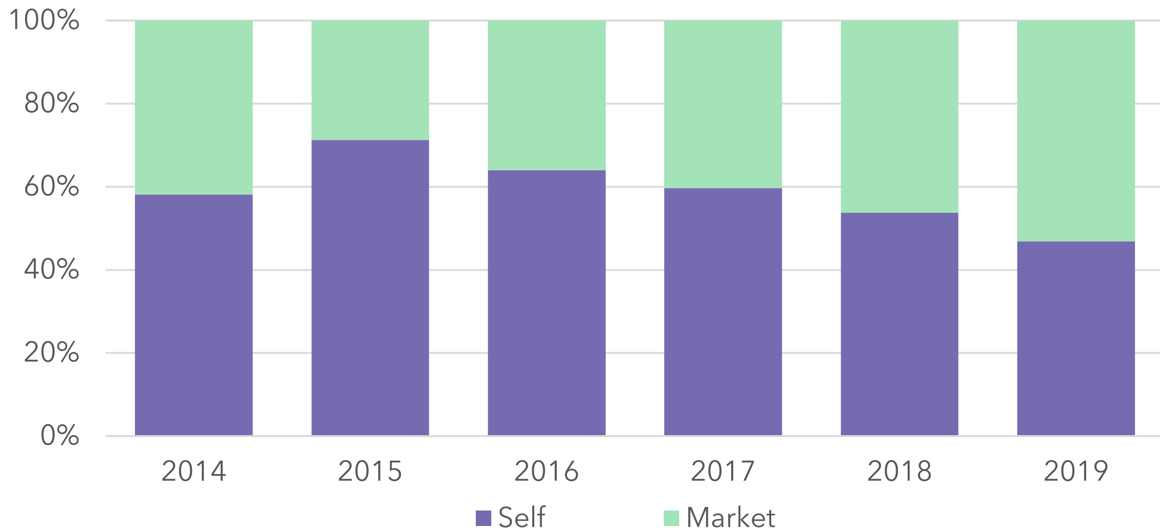
Key takeaways from this section include:

- The volume of self-committed megawatts declined over the study period, but remains nearly half of the total megawatt volume produced in the day-ahead market.
- Resources with long lead times and/or high start-up costs tend to self-commit instead of market-commit.
- Units that self-commit generally have much higher capacity-factors than those who market-commit. However, capacity factors by commitment status differ substantially by fuel type.

4.1 UNIT COMMITMENT – COMMITMENT STATUS

Figure 4–1 shows the percentage of day-ahead economic dispatch megawatts by commitment type over the study period.

Figure 4–1 Percentage of megawatts dispatched by commitment status



The volume of self-committed megawatts has declined over the last several years, but remains nearly half of the total dispatch megawatt volumes. In other words, nearly half of the energy produced was from a resource that was not selected by the day-ahead market's centralized unit commitment process.

While a relatively small percentage[34] of the self-committed megawatts were block-loaded,[35] many self-committed resources have operating parameters that include non-zero economic minimums.[36]

Even though resources are self-committed in the market, there also tends to be economic capacity above minimum that the market can dispatch. Figure 4–2 shows the percentage of self-committed dispatch megawatts above economic minimums.

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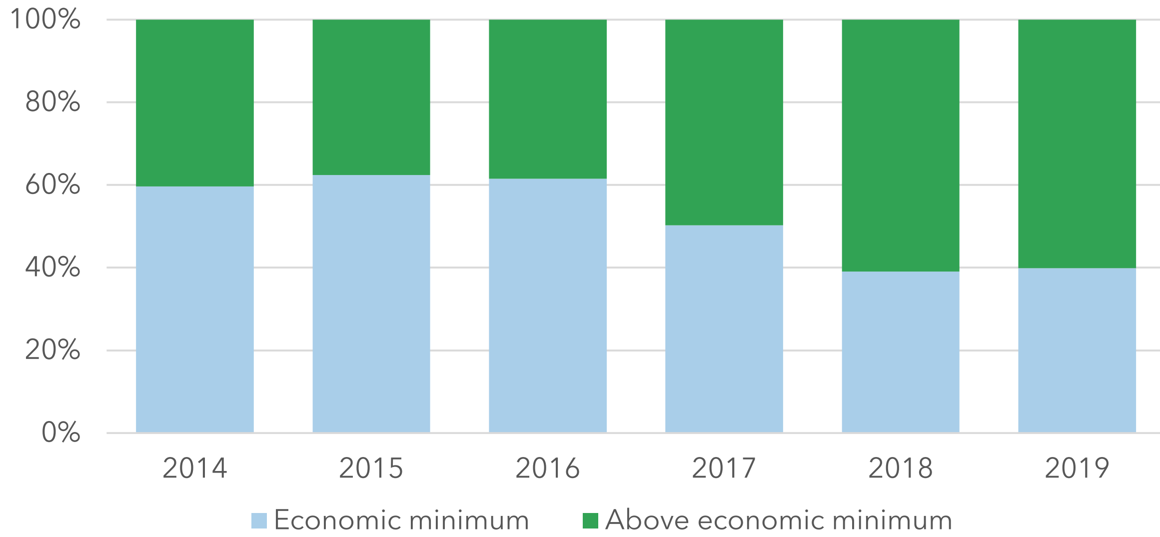
[34] Over the study period, block loaded self-committed resources averaged about six percent of total self-committed volume.

[35] Block-loaded resources self-schedule by submitting one point offer curves, where economic dispatch range is zero, i.e. where economic minimum and economic maximum values are identical.

[36] Integrated Marketplace Protocols, Exhibit 4-6: Resource Limit Relationships, "Minimum Economic Capacity Operating Limit"

Figure 4–2 Percentage of self-committed megawatts dispatched above economic minimum



While the trend is decreasing, economic minimums amount to roughly forty percent of all self-committed dispatch megawatts.

4.2 UNIT COMMITMENT – FUEL TYPE

Resource fuel type is a useful classification of resources. Generally, the operating parameters and economics tend to be similar among units of the same fuel type. Operating parameters tend to be physical or time-based and include items like ramp rate, minimum run time, and lead time. Economic parameters include operating cost. In auction based ISO/RTO markets, the capital/fixed cost[37] portion is generally recovered through market revenues and public service commission rate cases, whereas allowable fuel and short-term maintenance cost[38] is incorporated directly into energy market offers.

In the absence of market power, the centralized unit commitment optimization uses the suite of unmitigated offers when it chooses the lowest cost generators. In general, a low (operating)

[37] Capital cost is also referred to as fixed cost (there is also fixed overhead & maintenance).

[38] Operating cost is also referred to as variable cost.

cost position on the supply curve comes at the expense of high fixed costs. Because fossil fuel generators tend to be quite levered to the price of fuel, the tradeoff between capital cost and operating cost can change if fuel prices decline significantly. This means that each generator's cost position can change, perhaps dramatically, based on fuel prices.

Figure 4–3 shows the percentage of self-committed dispatch megawatts by fuel type by year. Over the study period, the largest portion of self-committed dispatch megawatts sourced from coal units. Coal self-committed megawatts generally exceed the size of the second largest fuel type by a factor of more than four to one.

Figure 4–3 Percentage of self-committed megawatts by fuel type

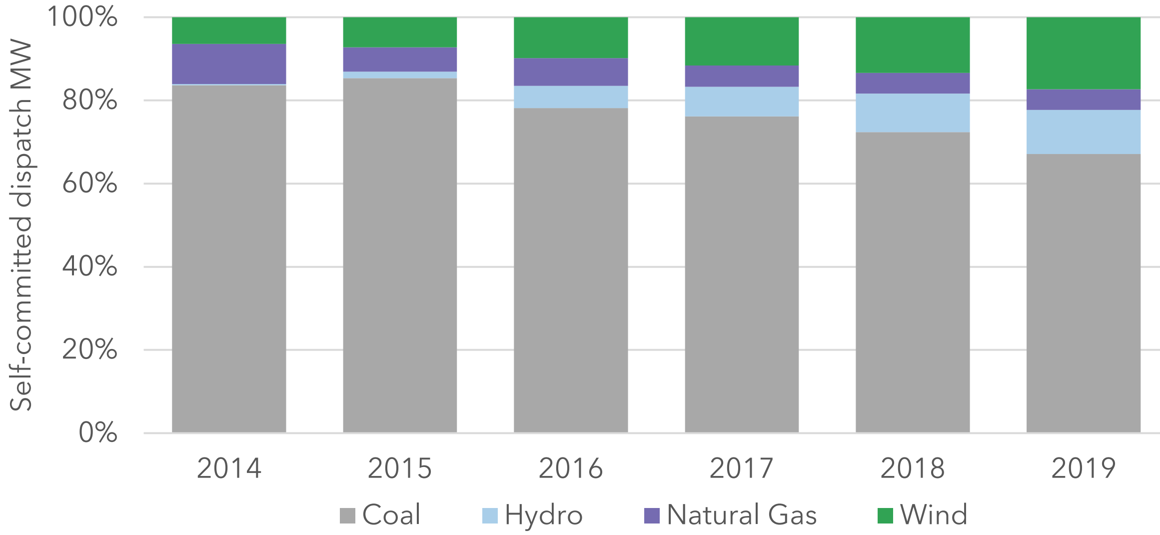


Figure 4–4 shows the percentage of market-committed dispatch megawatts by fuel type by year. Over the study period, the largest portion of market-committed dispatch megawatts sourced from natural gas units. However during the first year of market operation, coal units made up the largest share of market-committed megawatts.

Figure 4–4 Percentage of market-committed megawatts by fuel type

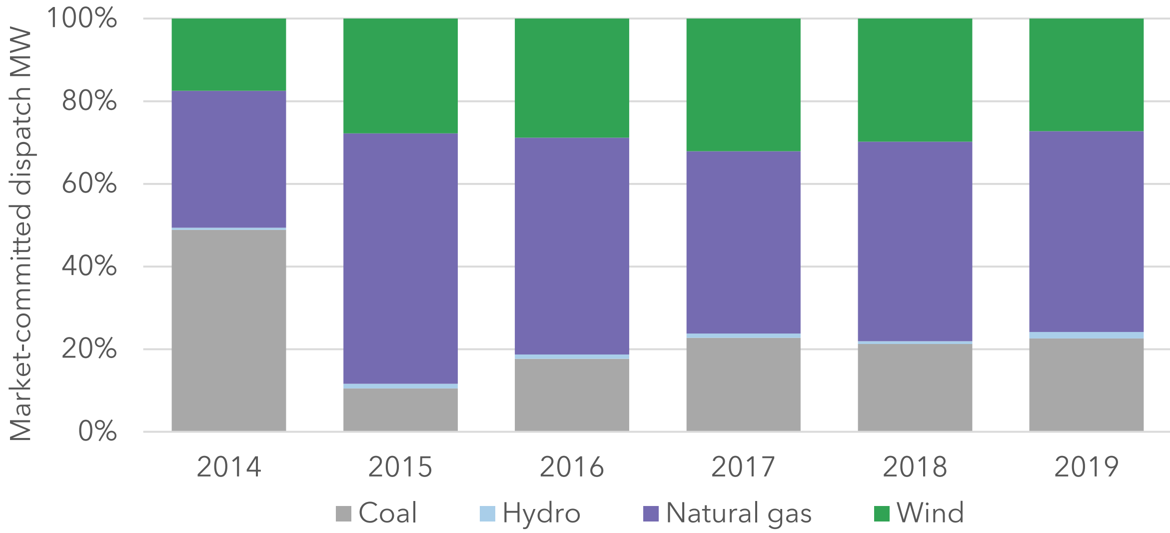
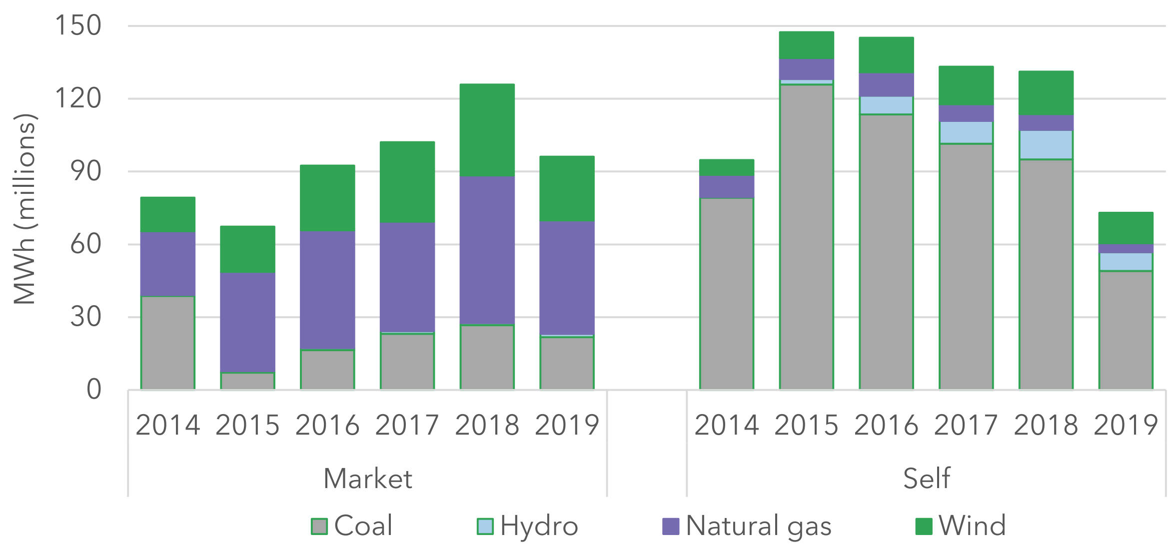


Figure 4–5 shows dispatch megawatts by fuel type by commitment type for each year of the study period.

Figure 4–5 Dispatch megawatt hours by fuel type by commitment type



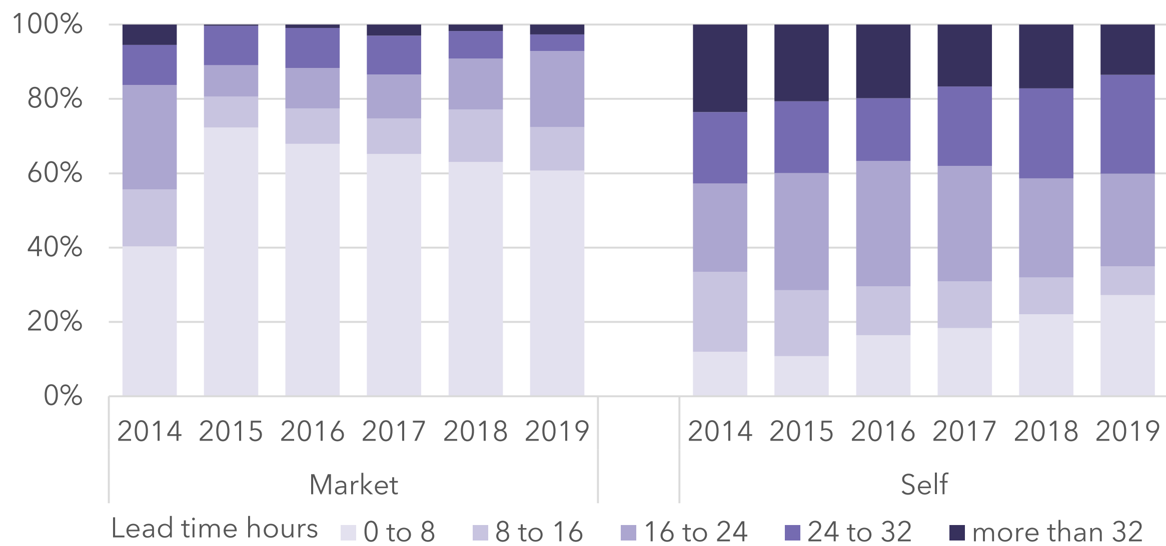
For the total period of March 2014 to August 2019, the magnitude of coal self-committed dispatch megawatts essentially equaled the total dispatch megawatts from all market-committed resources over the same period. In 2015 and 2016, self-committed coal greatly exceeded market commitments. However, as seen in 2019, self-committed coal megawatt hours, while still quite large, do not exceed market committed megawatt hours.

4.3 UNIT COMMITMENT – START-UP TIME

Resource lead times, also called start-up times, are time based operational parameters that vary widely by fuel type. In the Integrated Marketplace, resources can submit three different lead times: cold, intermediate, and hot. Thermal resources generally have longer lead times when they are cold as opposed to when they are hot. In the following section, we examine lead times by commitment status and fuel type.

Figure 4–6 shows the relationship between commitment status and start-up time.

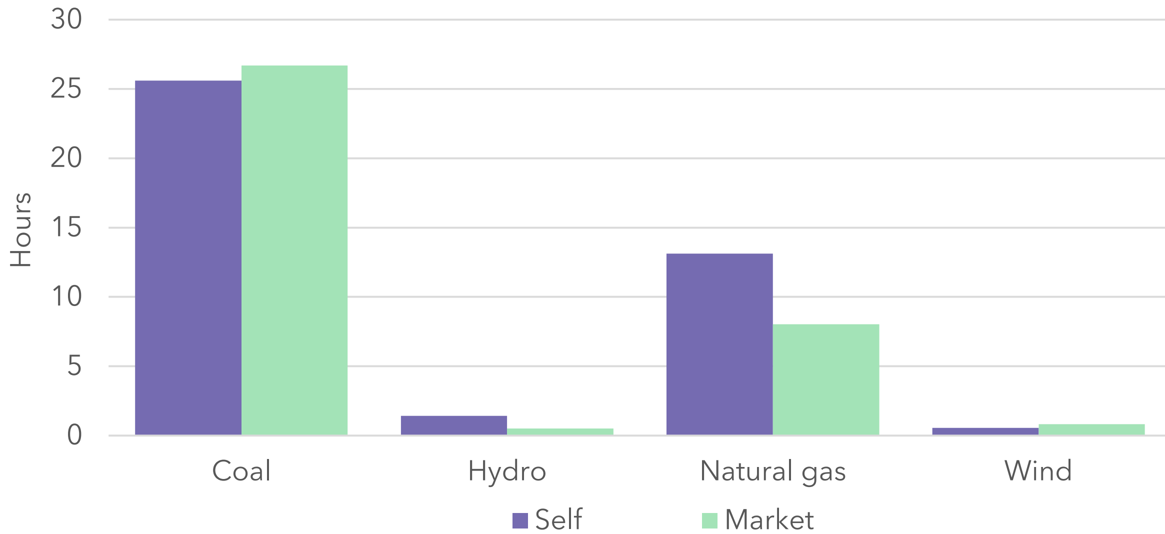
Figure 4–6 Lead time hours by commitment status



Self-committed resources tend to have longer lead times than market-committed resources. Because centralized unit commitment must observe constraints other than cost, it may not select a unit even if that unit's offer falls below the marginal resource.

Coal units have the longest cold start-up time, followed by natural gas. Figure 4–7 shows the dispatch megawatt weighted cold start-up time by fuel type by commitment type

Figure 4–7 Dispatch megawatt weighted lead time by fuel type by commitment status



Natural gas generators have the largest difference in start-up times between self-committed and market committed resources compared to other resources. Coal resources show relatively little deviation in their cold start-up time.

4.4 UNIT COMMITMENT – START-UP COST

Start-up cost is submitted in terms of dollars per start.[39] These parameters also vary widely by fuel type. Like start-up time, resources can submit three different start-up costs: cold, intermediate, and hot. Thermal resources generally have more expensive start-up costs when they are cold, as opposed to when they are hot. Additionally, start-up costs are non-convex which makes it hard for the market clearing algorithm to achieve an optimum solution.[40] However, when price taking behavior combines with good information, the market's efficiency can be improved.[41] In the following section, we examine start-up cost by commitment status and fuel type.

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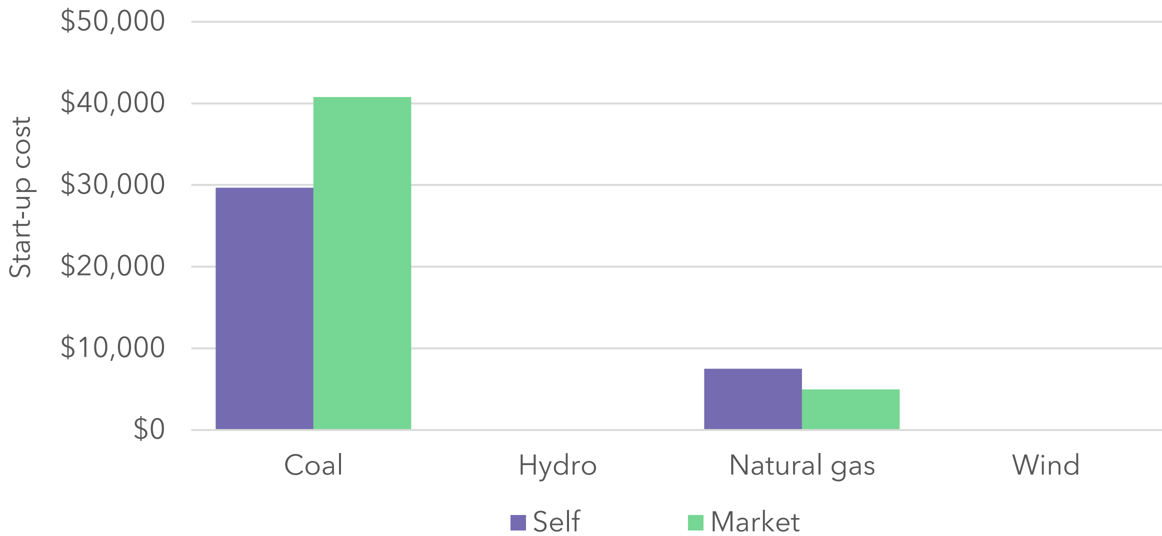
[39] Integrated Marketplace protocols, G.2.6.1 Start- Up Offer Definitions

[40] https://www.ferc.gov/legal/staff-reports/2014/AD14-14-operator-actions.pdf

[41] Steven Stoft, Power System Economics, p.55

Coal units have the highest cold start-up cost by more than a factor of five over the next highest start-up cost fuel type as seen in Figure 4–8. Coal start-up costs and gas start-up costs correlate strongly with gas prices.[42]

Figure 4–8 Dispatch megawatt weighted start-up cost by fuel type by commit status



Unlike start-up time, start-up cost differs materially for both coal and natural gas resources by commitment type. The difference between the market-committed cold start-up cost of coal and natural gas is even more significant than the relationship called out in Figure 4—7. Interestingly, market status based coal start-up costs exceed the start-up costs of self-committed resources. In market status, the cold start-up cost of coal exceeds that of natural gas by a factor of more than eight to one.

4.5 UNIT COMMITMENT – START-UP OFFERS

Start-up offers are generally representative of the cost that a market participant incurs when starting a generating unit from an off-line state to its economic minimum as well as the cost to eventually shut the unit down. These offers are submitted in terms of dollars per start.

[42] Over the study period, the correlation between natural gas start-up costs and Henry Hub gas prices is 78 percent, whereas the correlation between coal start-up costs and Henry Hub gas prices is 65 percent.

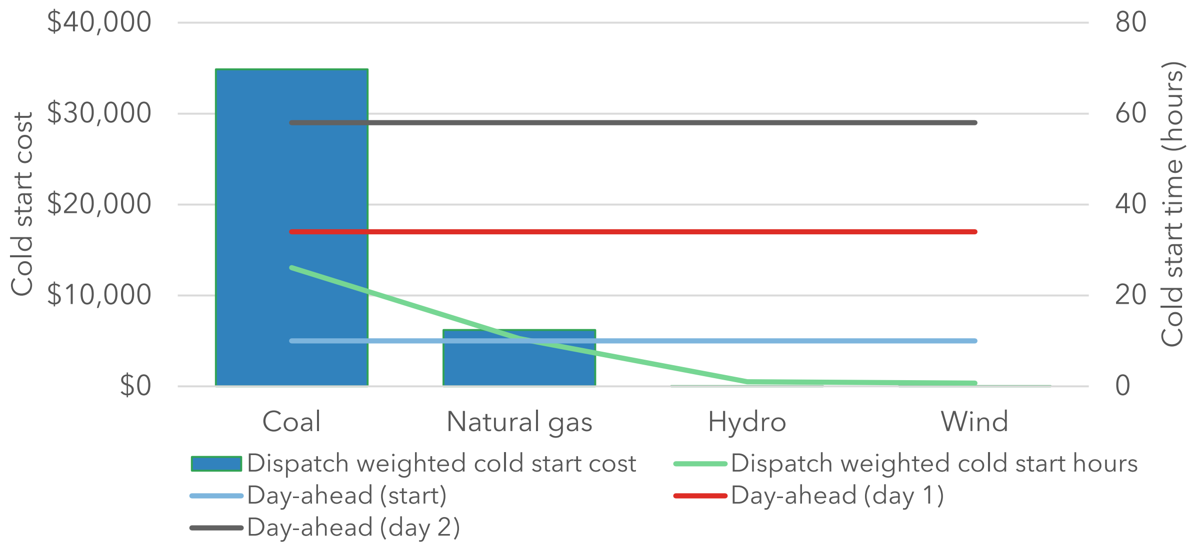
However, the optimization evaluates the offer in dollars per start per hour. The start-up cost is optimized and later amortized over the lesser of the resource's minimum run time or the number of hours from start time through the end of the day-ahead market window.[43]

While the financially binding day-ahead market covers only one operating day, the day-ahead market optimizes over a two-day window – the operating day and the next operating day. However, only the results from day one of the unit commitment solution feed forward to the economic dispatch algorithm. The results from the second day of the optimization are non-binding and are not used for commitment purposes. The two-day optimization helps prepare for the following day's morning ramp and attempts to prevent any unnecessary starting and stopping of units from one day to the next.

Figure 4–9 compares cold start time and cold start cost (y-axes) by resource fuel type (x-axis). The horizontal reference lines (blue, red, black) call out various periods in the day-ahead market window. Hour 10 represents the time from the posting of day-ahead market results to the beginning of the day-ahead market day. The second line at hour 34 represents the end of the first day-ahead market day and the beginning of the second day-ahead market day. The third line at hour 58 represents the end of the second day-ahead market day. The blue bars relate to the left axis and the lines relate to the right axis. These two inputs are used in the construction of the start-up offer.

[43] The day-ahead market window covers two days.

Figure 4–9 Cold start time and cold start cost by resource fuel type



Many of the units with high start-up costs have minimum run times that extend past the day-ahead market window. If the optimization evaluated start-up costs over each resource's full minimum run time, their start-up offers would be more competitive with shorter lead-time resources. This issue compounds for those resources with long lead times and high start-up costs. Because these units cannot come online until much later than the first hour of the day-ahead market day, their start-up cost is optimized over even fewer hours.

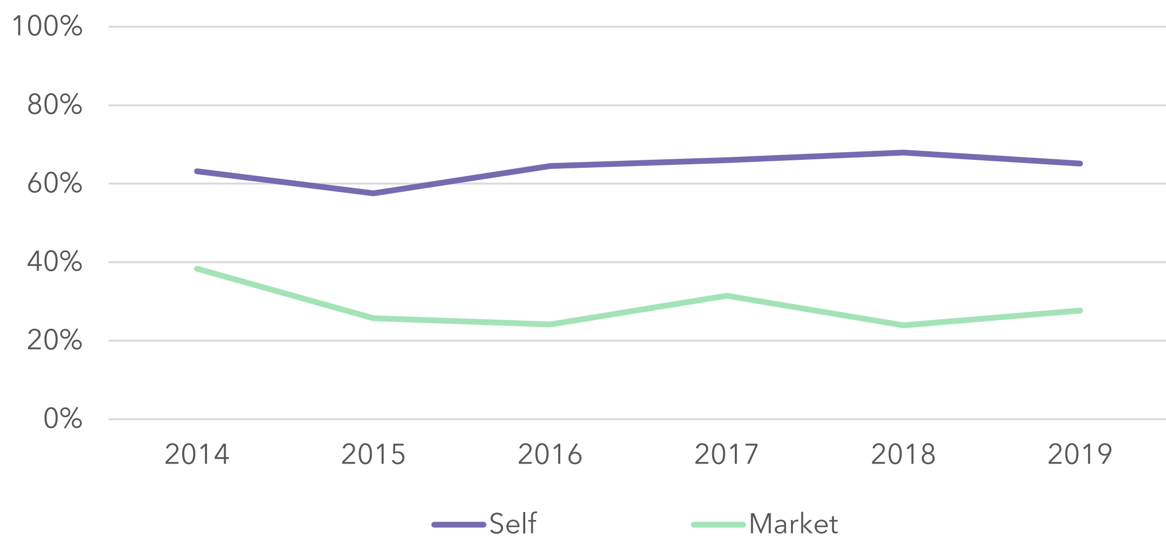
4.6 UNIT COMMITMENT – THE CAPACITY FACTOR

Because of the relationship between fixed cost and variable cost inherent in power generation, capacity factors are a central input when calculating a generator's long run average cost and by extension their long run economic viability.

A capacity factor is the ratio of energy output for a given period (usually a year) to the maximum possible energy output over the same period. The more energy a resource produces, the lower its fixed cost per unit of production. The relationship between fixed cost and marginal cost is often referred in other industries as operating leverage. If fixed costs are significantly larger than variable costs, a firm will exhibit high operating leverage.

The higher the operating leverage the more profit earned from an incremental sale and the more lost from a lost sale. The capacity factor is effectively the ratio of sales to potential sales for power plants.

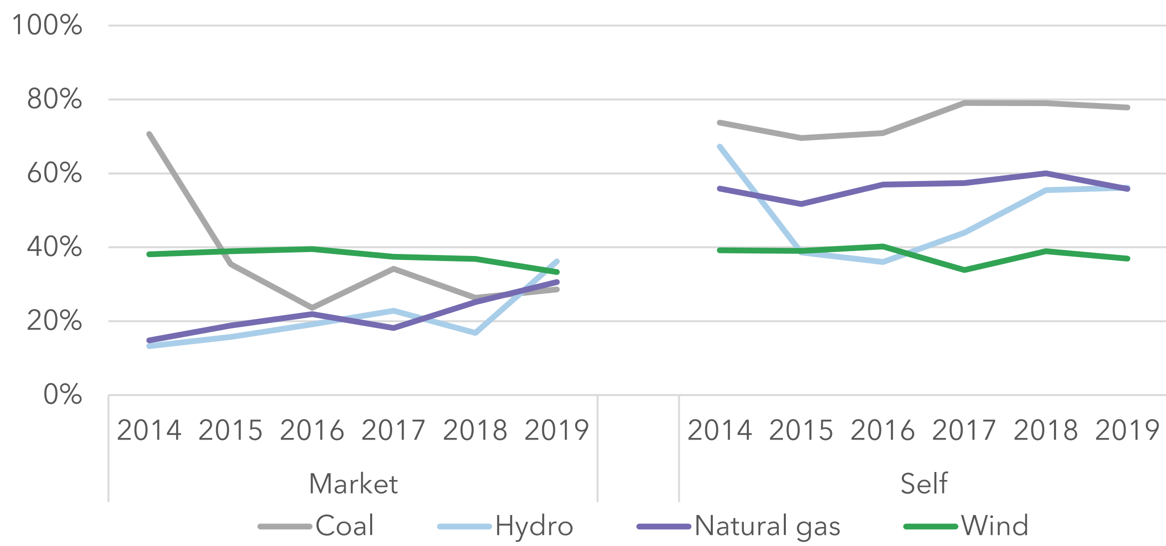
Figure 4–10 Capacity factors by commitment type



Over all resource fuel types, capacity factors roughly double when resources offer in self-status, as opposed to market-status.

Figure 4–11 shows the capacity factors by commitment type by fuel type. This figure shows that some fuel types (such as wind) have comparatively similar capacity factors irrespective of their offer status. However, some fuel types (such as coal and natural gas) have vastly different capacity factors when they are committed in market or self.

Figure 4–11 Capacity factors by fuel type by commitment type



Similar to capacity factors by fuel type, some turbine types have quite similar capacity factors when they are committed in market or self-status.

5 PRICE FORMATION

In this section, we build upon the price portion of the market feedback loop discussed earlier. Specifically, we provide empirical information and analysis reflecting the prices and production costs over the study period.

Key points from this section include:

- Over the study period, at least one self-committed unit was marginal in roughly 75 percent of the day-ahead market hours.[44]
- Over the study period, prices were systematically lower when at least one self-committed unit was marginal.
- In almost all cases, self-committed generators had lower revenues than market-committed generators because of negative congestion prices.
- In SPP's case, consumers and producers are not necessarily two distinct, organically separated groups.[45] This dynamic makes the impact of price levels and production costs less clear.

5.1 IMPACT OF SELF-COMMITMENT ON PRICE FORMATION

To quantify the impact of self-commitment on prices and price formation, we evaluate the frequency and magnitude of self-commitment in addition to the time it sets price. Self-committed resources can set price as many self-committed generators offer their incremental

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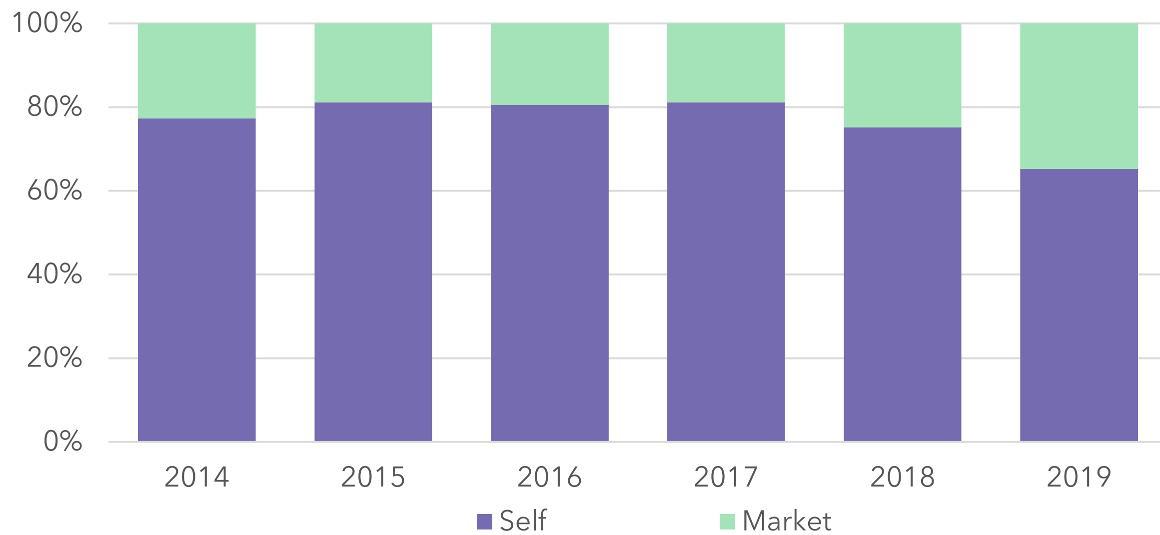
[44] More than one resource can be marginal during a given period.

[45] The participants—primarily the investor owned utilities—who serve load may also own or control both generation and transmission assets. In fact, in 2018 investor owned utilities owned 53 percent of the total nameplate generation capacity in the SPP market.

energy into the market. Self-dispatched resources are resources that do not allow the market to choose their incremental energy output.[46]

Figure 5–1 Percentage of day-ahead hours by marginal resource by commitment type



Over the study period, at least one self-committed resource was marginal in substantially more than half of the day-ahead market hours. For the purposes of Figure 5–1, if during an hour, a single marginal generator was self-committed, that hour is classified as self. If only market committed generators were marginal during the hour, that hour is classified as market.

Even though self-committed generators are treated as price insensitive suppliers in the unit commitment process, these same generators can set the marginal clearing price if they provide the marginal unit of supply when dispatched above their economic minimum. These units may not have been committed by the centralized unit commitment had they been offered in market-status, and by extension, may not have otherwise been marginal. This is one of the reasons market participant's unit commitment decisions can affect price formation.

However, in any given hour, there is likely to be more than one marginal price setting resource because of the effects of transmission congestion. Figure 5–2 captures this effect. It looks at all

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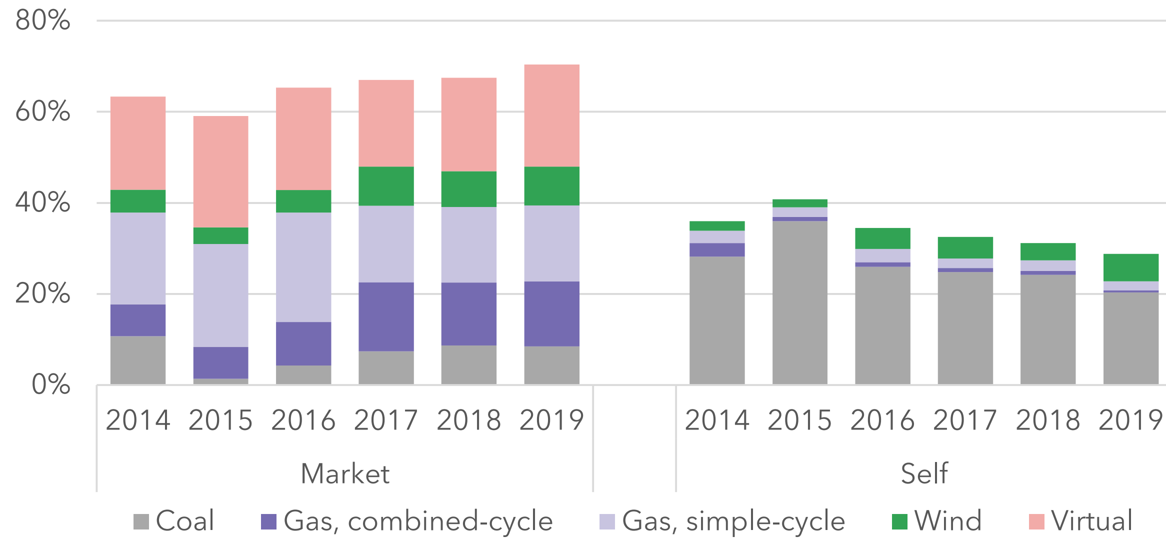
[46] For example, non-dispatchable variable energy resources (NDVERs) are self-scheduled as opposed to self-committed. However, for the purposes of this analysis, we have including NDVER as self-committed.

the marginal resources in the market and finds that over the study period, market-committed resources[47] were on the margin setting prices during roughly two-thirds of all instances in the day-ahead market whereas self-committed resources set prices during roughly one-third of all instances day-ahead.

Figure 5–2 Percentage of marginal hours by fuel type

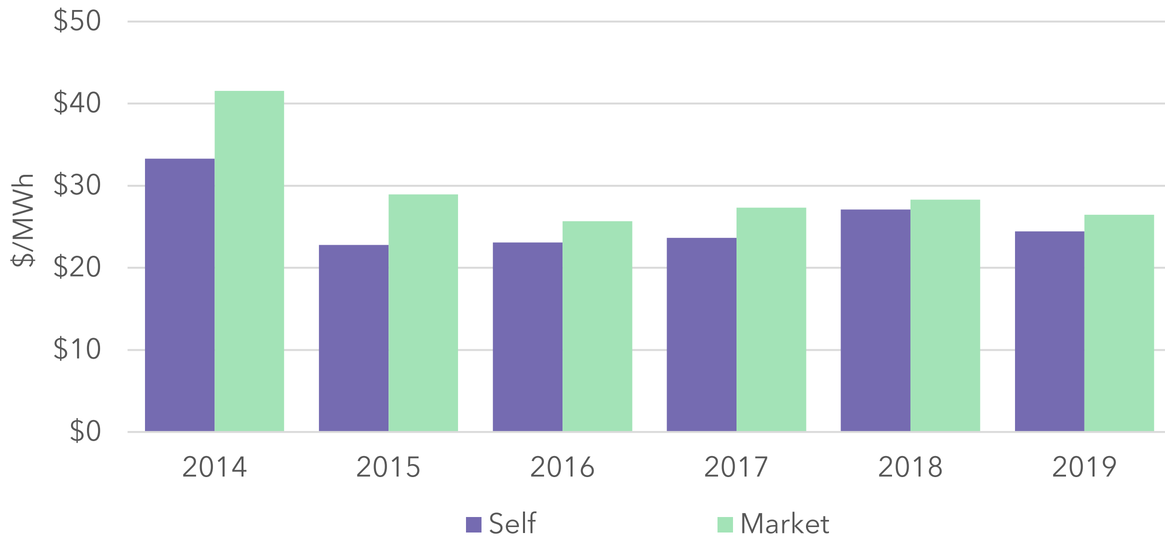


Of the market committed-units, wind, virtual, and combined-cycle gas resource types have increased their time setting prices on the margin, while simple-cycle gas and coal generators have decreased their time setting prices on the margin.

Of the self committed-units, coal dominates the time on the margin compared to all other fuel types. Wind on the margin continues to grow, whereas the frequency of coal on the margin, while still quite large, continues to decline.

[47] We have classified virtual transactions as market committed for the purpose of this analysis.

Figure 5–3 Average day-ahead system marginal prices by marginal unit commitment type



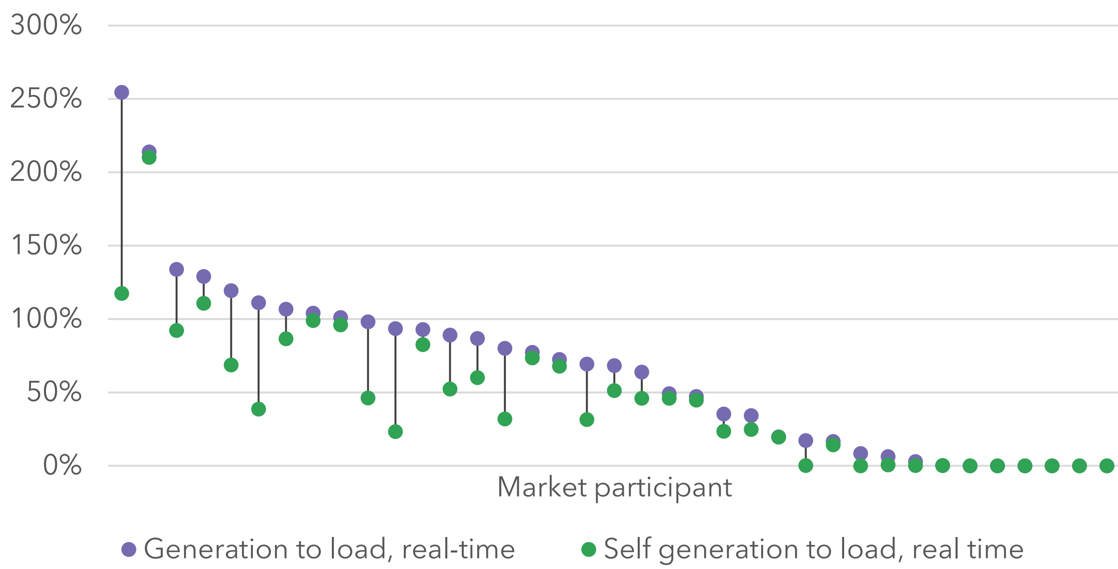
Over the study period, prices were systematically lower when at least one self-committed unit was marginal.

5.2 WHO PAYS?

SPP market participants have indicated in stakeholder meetings, that in a cost-of-service regulated market, when participants are vertically integrated, the load ultimately pays and therefore will benefit from lower prices and production costs. However, when participants are vertically integrated, the load is also the generation in terms of integrated ownership. Low prices do indeed benefit load, but they do not benefit generation. Because these entities are not distinct, and must carry generation capacity to meet their capacity obligation, the "who benefits" question with respect to the level of prices is nuanced.

Figure 5–4 highlights two things. First, it shows the level of generation produced by a participant relative to its load. Second, the figure shows the level of self-committed generation relative to its load.

Figure 5–4 Generation megawatts to load megawatts by commitment type



The purple dots above 100 percent line denote a market participant who produced energy in excess of its real-time load obligation. The inverse indicates a market participant who produced less than their real-time load. In a competitive market, it would be expected that some would produce more than their load and some would produce less, as lower cost resources would displace higher cost resources.

The green dots show the self-committed generation relative to load. The green dots above the 100 percent line denote a market participant whose self-committed energy production exceeded their corresponding real-time load. The inverse indicates a market participant whose self-committed units produced less than their real-time load.

The figure shows that there are three participants that self-committed more generation than their load. In this case, the participant would be selling self-committed generation to the market. Furthermore, the chart shows that some participants self-committed almost all of their generation (purple and green dot the same or very close) and that the majority of participants self-committed some generation. This highlights how difficult it is to determine who benefits from higher or lower prices.

5.3 CONGESTION

Congestion price signals incentivize the behavior of market participants. When locational marginal prices are elevated, generators in that particular pricing node earn more. Because every node in the system includes the system marginal price, the difference in locational marginal prices stems mostly from the marginal congestion component of the locational marginal price.

Congestion affects all resources. However, in the SPP market, it tends to affect resources differently as seen in Figure 5–5. Natural gas resources tend to have higher prices as a result of congestion, while coal and wind resources tend to have dramatically lower prices. The congestion profile is more balanced for units that market-commit. Some market generators earn more than the system marginal price and some earn less, whereas generators who self-commit almost always earn less than the system marginal price.

Figure 5–5 Congestion dollars by fuel type, by commitment status

Additionally, Figure 5–5 brings to light an additional price signal. Congestion prices, similar to energy prices, provide feedback to market participants. When congestion reduces generator revenues, the market's general message is twofold: generators are incented to do less of what they are doing in the short-run and generators are incented not to build additional generation in the long run. The market also uses congestion to convey information to transmission owners.

In this case, if participant behavior does not change, transmission owners will likely be incented to build additional transmission infrastructure. When generator congestion is positive, the market generally conveys the opposite information to market participants. As an extension of our message in Section 3, self-commitment also blurs the congestion price signal.

In Figure 5–5, the green bars represent the market commitments and is more desirable than the purple bars because the unit commitment process committed that resource, not the market participant. What we do not know, however, is if the market-committed unit earned its commitment to offset a constraint created or enhanced by a self-committed unit. The purple bars below zero might also represent the market software attempting to incent different commitment behavior.

Both generators and loads are assessed congestion costs. Generators pay congestion through reductions in the locational marginal price. Loads pay congestion through increases in the locational marginal price. On balance, we observe that generation has been assessed more congestion than load in the Integrated Marketplace.[48]

Because self-commitment affects congestion, it also affects SPP's congestion hedging market. One way of scaling this impact is to compare average transmission congestion right (TCR) profitability by marginal unit commitment type by hour, which is the same classification methodology used in Figure 5–1.

[48] MMU Quarterly State of the Market Report, Spring 2019, Special Issues

Figure 5–6 Transmission congestion right revenue per megawatt by marginal unit commitment status

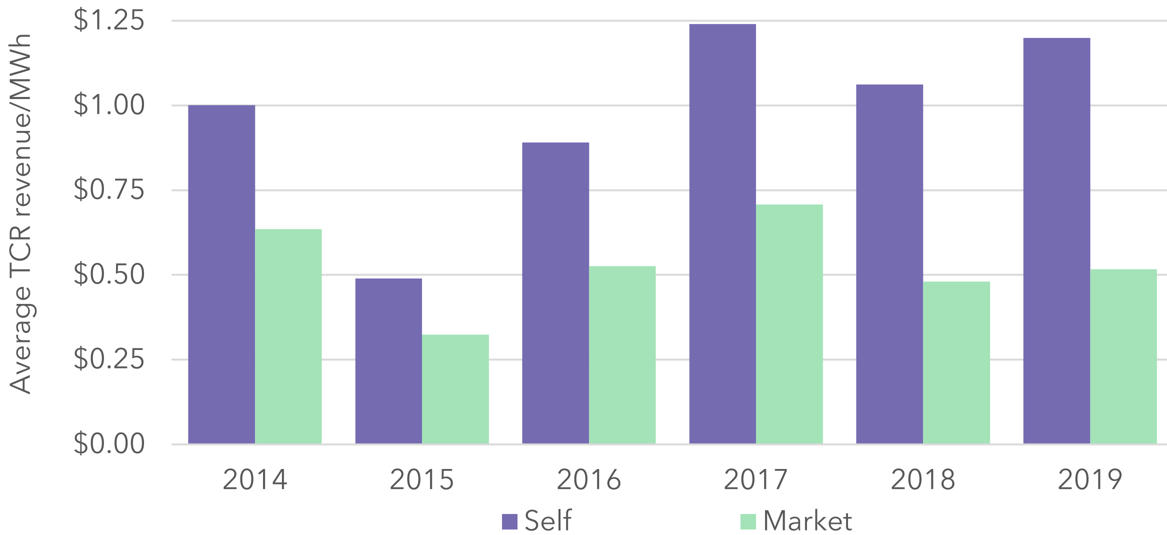


Figure 5–6 shows the revenue per megawatt of transmission congestion rights[49] was significantly higher when at least one self-committed unit was marginal. Our general takeaway is that in hours when at least one self-commit unit is marginal the system is more congested when compared to hours where only market-committed units are marginal. By extension, the congestion revenues from congestion hedges increase during hours where at least one self-committed unit is marginal.

[49] Figure 5—6 includes self-converted transmission congestion rights, long-term transmission congestion rights, and the positions purchased and sold in the various auctions.

6 SELF-COMMITMENT SIMULATIONS

In this section, we perform three simulations to study the effect of market committing resources that participants currently self-commit in the day ahead market.

6.1 OVERVIEW

To study the impact of self-commitment on market results, we re-solved the Integrated Marketplace's day-ahead market. In our study, we executed three scenarios using the effective version of the actual Integrated Marketplace software associated with each operating day. In each of the scenarios, we simulated the centralized unit commitment and economic dispatch optimizations.

In our first scenario, we validated our process by rerunning the original day-ahead market and compared the validation results to the original results. The validation cases were then used as the base inputs to scenarios two and three.

In scenario two, we changed the offer status from self to market for all resources that originally elected self-status. We also turned off all resources, so the market could make all unit commitment and dispatch decisions without optimizing the generators already producing power. Scenario three builds on scenario two, and includes the same input modifications in addition to reducing lead times to simulate extending the day-ahead market optimization window.

Findings from the simulations include:

- The key to reducing self-commitment while not increasing costs is multi-day economic unit commitment.[50]

[50] Our position supports the findings of The Holistic Integrated Tariff Team's Reliability Recommendation #3 – Implement Marketplace enhancements. Specifically, Multi-day market.

- Increasing the optimization window by another 24 hours allows the market to more effectively optimize resources with long start-up times. This enhancement combined with a reduction in self-commitment, would likely benefit ratepayers by reducing production costs in addition to sending more clear investment signals.
- If the optimization window is not lengthened, and self-commitment is eliminated, investment signals would be more clear, but production costs would likely increase.

6.2 STUDY DETAILS

6.2.1 SCENARIO 1 – VALIDATION SCENARIO

The purpose of the validation scenario is to determine the legitimacy of our testing framework. As with many electricity markets, SPP's software uses a mixed-integer optimization program that solves for optimal commitment and dispatch. Because of the nature of this type of software, it is not always possible to reproduce the original results even with identical inputs. For this reason, we rejected several market days from our study where the hourly production costs fell outside our tolerance when compared to the original market solution.[51]

Because of simulation run-time constraints, the study period includes one week of each month from September 2018 through August 2019. In addition to the data being readily available, this period also includes the different annual seasons and a wide variety of market conditions. The testing criteria, sample size, and results of our validation scenario gives us confidence in our process.

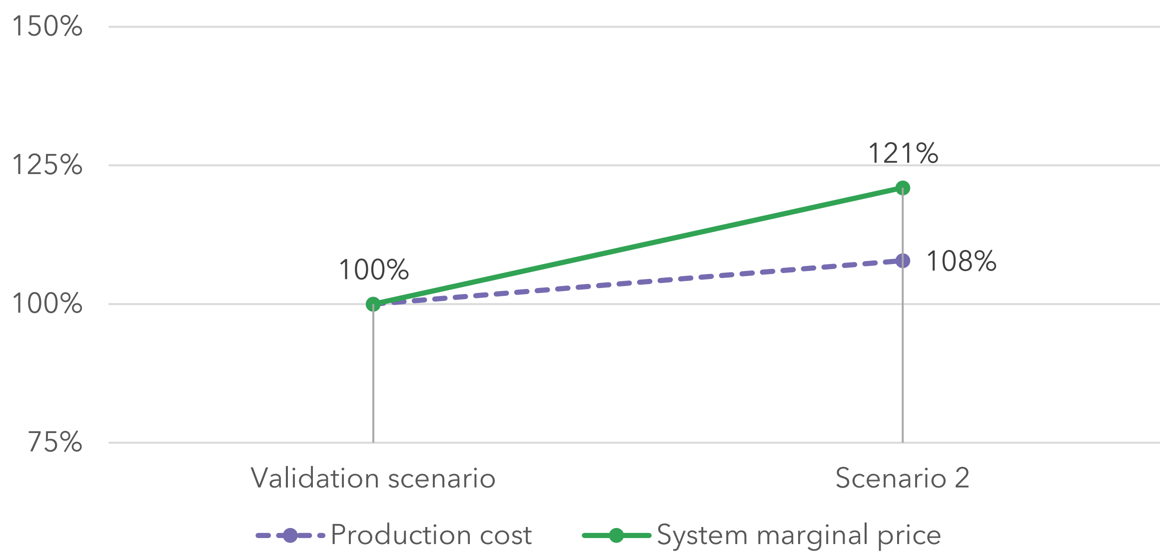
[51] We discarded market days for which the coefficient of determination of hourly production costs between the original market solution and the validation solution were less than 95 percent, representing about eight percent of market periods simulated. The remaining days averaged 99.5 percent coefficient of determination between the original solution and the validation solution. When simulating a market day, small differences in the calculation of hourly commitment or dispatch levels can compound in subsequent hourly solutions, leaving the final solution set for a day significantly different from the original market solutions.

6.2.2 SCENARIO 2 – UNITS CHOOSE "MARKET"

A number of changes were made to the validation data set prior to executing scenario two. Resources that were originally offered to the day-ahead market in self-status were set to market-status, de-committed at the start of each study period, and treated as having met their minimum down time before each continuous study period to allow for immediate commitment by the market engine.

Figure 6–1 shows the results of scenario two in terms of change in prices and production cost relative to the validation scenario.

Figure 6–1 Scenario 1 vs Scenario 2, system marginal price and production cost



In scenario two, marginal energy prices increased in excess of twenty percent, which was more than $6/MWh. Also in scenario two, production costs increased roughly eight percent, or more than $22,000 per hour. The results suggest that the current market software cannot more efficiently commit and dispatch all available units in the absence of self-commitment. As we discussed earlier in this report, the length of the optimization period is one of the software's limitations. As such, scenario two represents the market software's optimal solution given the current market structure if all resources did not self-commit.

6.2.3 SCENARIO 3 – UNITS CHOOSE "MARKET" AND OPTIMIZE LONG LEAD TIMES

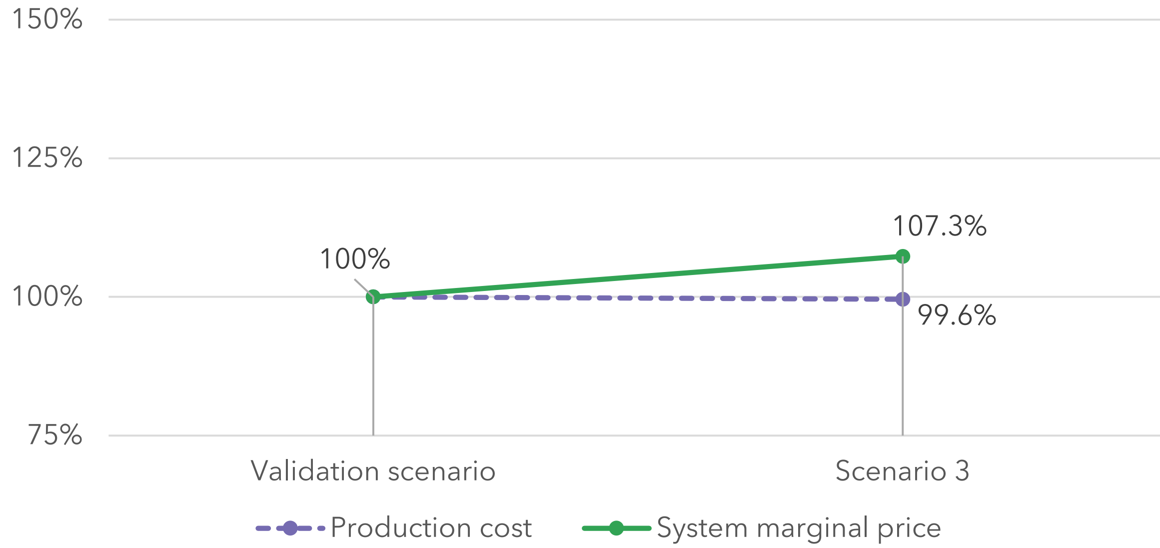
Scenario three expands on scenario two by simulating the lengthening of the optimization period of the day-ahead market. Effectively, this scenario attempted to create a multi-day economic unit commitment. This enhancement directly addresses one of the current limitations of the market software – optimizing long-lead time resources. As we mentioned in the unit-commitment section, long-lead time resources, especially those with high start-up costs, tend to be uncompetitive, in part, because of the duration of the current market optimization window.

Lengthening the optimization window includes long-lead resources that would otherwise be excluded from the optimization and decreases the hourly-amortized start-up amount, making these resources more competitive. Lengthening the optimization window by an additional day resolves the majority of these cases.

The length of the optimization window is not configurable in the current software. Therefore, to simulate an increased optimization window, we decreased the start-up times of resources with startup times greater than 23 hours to 12 hours. This change allows the current day-ahead market software to commit the resource in a manner which simulates the presence of a lengthened economic commitment mechanism.

Figure 6–2 shows that in this scenario prices increased, but production cost decreased when compared to the validation scenario.

Figure 6–2 Scenario 1 vs Scenario 3, system marginal price and production cost

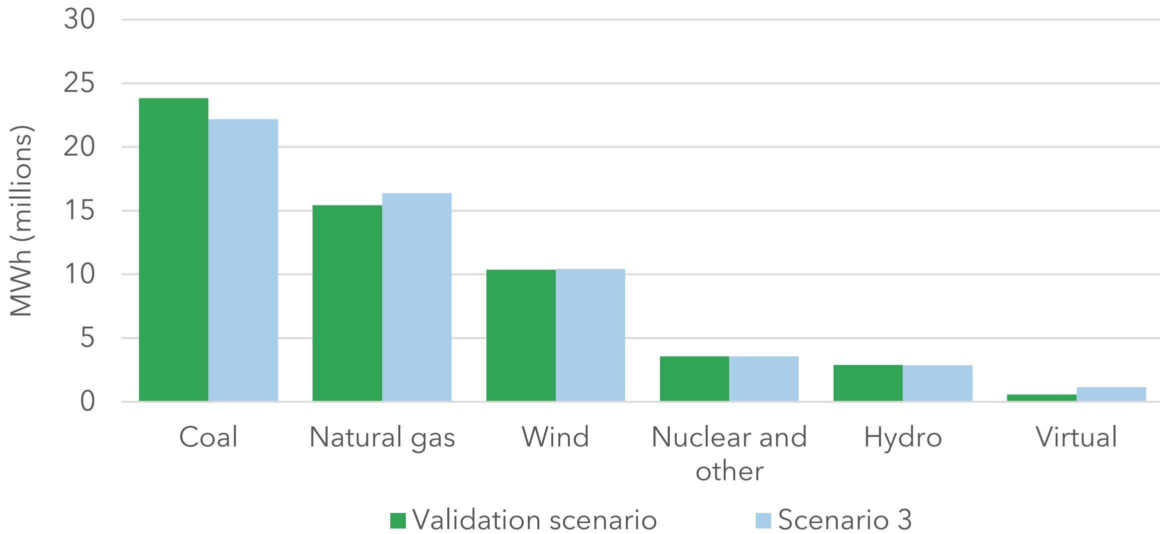


On average in every hour of the study period, system marginal prices were higher when all units market-committed. This is the same directional result as in scenario two and a predicted result based on the change in the supply curve as discussed in section two. The average system marginal price over all hours increased more than seven percent, about $2/MWh on average. The average production cost change over all hours decreased roughly one-half of one percent, or $1,750 per hour.

These results suggest that a purely economic commitment model, if able to consider and commit long lead-time resources, would lead to somewhat higher market prices and potentially more accurate investment signals while potentially reducing production costs. Given this result, we would prefer scenario three to scenario two.

Not only did the optimization change prices, it also changed dispatch quantities. Figure 6–3 shows the change in dispatch megawatts between scenario three and the validation scenario.

Figure 6–3 Scenario 1 vs Scenario 3, dispatch megawatts by fuel type



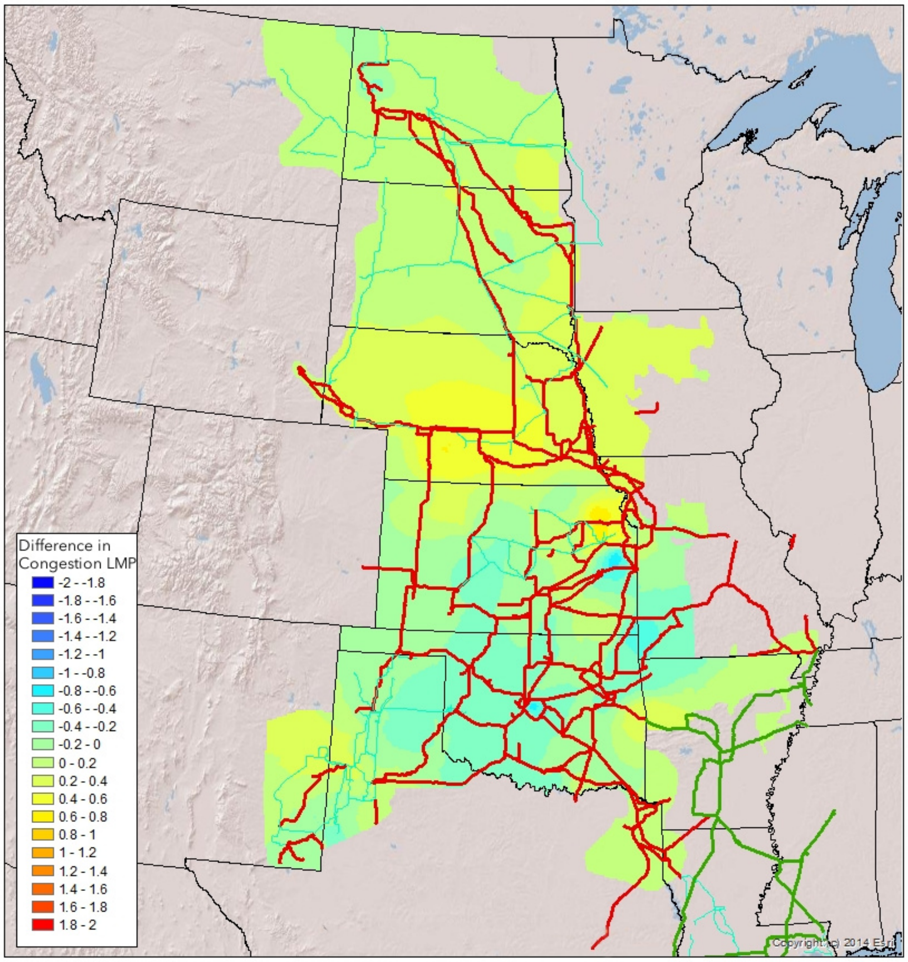
In scenario three, coal energy awards decreased seven percent, when compared against the validation scenario. Natural gas and virtual supply replaced the majority of the reduction in coal. Because changes in self-commitment affect prices, and virtual participation is based on projected prices, we expect virtual trading behavior would also change. However, we are unable to simulate how virtual participants might change their behavior in this analysis.

Any structural change to the SPP markets would likely cause a redistribution of marginal generation that can have far-reaching impacts on congestion, local pricing, and congestion hedging products. In order to visualize the net congestion differences between the original market solution and this scenario, we graphed the difference in the marginal congestion component (MCC) of the locational marginal price over the study period.

Generally, congestion reflects supply and demand relationships between producers and consumers in a given area. When an area is oversupplied with generation, congestion prices tend to be lower. Likewise, an area undersupplied with generation will tend to have higher congestion prices. This framework translates into the figure below.

Figure 6–4 shows the change in congestion between scenario three and the validation scenario. Higher congestion prices (yellow and orange) indicate increase in prices from the validation scenario to scenario three, and lower prices (green and blue) reflect price reductions in scenario three relative to the validation scenario. Ultimately, changes in congestion prices ranged between a decrease of approximately $1/MWh and an increase of approximately $1/MWh over the study period.

Figure 6–4 Scenario 1 and Scenario 3 comparison, difference in congestion costs



The majority of the supply reductions are in the coal-dominated regions of the footprint, which leads to a slight increase in congestion pricing in those areas. Accordingly, much of the replacement energy committed and dispatched to serve the day-ahead demand comes from gas-fired generation in the southern portion of the footprint, leading to a slight reduction in congestion pricing around those units.

7 CONCLUSION

Self-commitment represents a significant portion of the transaction volume in the Integrated Marketplace, and while it cannot be eliminated completely, the practice can likely be reduced substantially. By reducing self-commitment, prices and investment signals will likely be less distorted. A smaller distortion will likely help market participants make better short-run and long run decisions, which tends to coincide with improved profit maximization. Enhanced profit maximization combined with effective regulation and monitoring will likely lead to ratepayer benefits in the form of cost reduction.

While we have seen gradual reductions in self-commitments over the last few years, generation from self-committed generators still represent about half of the generation in the SPP market. Given our results, we recommend that the SPP and its stakeholders continue to find ways to further reduce self-commitments. Many resources have switched from self-commitment to market status over the past few years, and it is possible that many more could switch without any market enhancements.

However, as we presented in our simulations, simply eliminating self-commitment without any additional changes could result in an increase in total production costs. This would not necessarily be an improvement when compared to today's results. However, when lead times were shortened to reflect an additional day in the market optimization and self-commitment was eliminated, producers were paid more and production costs declined.

The efficiency gain stems largely from an improvement in the optimization of nonconvex costs, specifically start-up costs. In the current construct, units with long lead times, high start-up costs, and long minimum run times may be uneconomic over a single day, but economic over a longer period. Extending the optimization period helps bridge this gap. However, as the optimization period lengthens, it must solve for variables further into the future where there is more uncertainty. However, empirical evidence suggests that the accuracy of wind and load forecasts remain acceptable over a two-day optimization window.[52]

For these reasons, and others covered throughout this report, we support the HITT recommendation of evaluating a multi-day optimization,[53] and see this as an enhancement that can improve market efficiency and help further reduce the incidence of self-commitment. Specifically, we recommend that SPP and its stakeholders consider a multi-day commitment period of two days to allow units to commit long lead time resources.

[52] Market Working Group Meeting Materials – February 2019 – 10.b.i.MultiDay Forecast_021919

[53] See footnote 50.

UTILITY DIVE

BRIEF

MISO: Majority of coal is self-committed, 12% was uneconomic over 3-year period

By Catherine Morehouse

Published May 7, 2020

Dive Brief:

- The majority of coal-fired power in the Midcontinent Independent System Operator (MISO) was self-scheduled and 12% was dispatched uneconomically from 2017 to 2019, according to an April analysis from the grid operator.
- Approximately 76% of coal-fired power in the market was self-scheduled and dispatched economically during that time period, while the remaining 12% was economically committed and economically dispatched.
- MISO's numbers largely support assertions made by the Union of Concerned Scientists and other advocacy groups, which have found that "bad actors" are running their coal plants uneconomically, and costing ratepayers billions of dollars, Joe Daniel, senior energy analyst at UCS told Utility Dive.

Dive Insight:

Utilities in the MISO market have been under increased scrutiny over the past few years from regulators and advocacy groups trying to understand how much money the market could potentially be losing over self-scheduling practices.

Sierra Club previously estimated that self-scheduling practices have cost MISO $1.29 billion in 2017 alone and that the practice as a whole cost ratepayers across markets $3.5 billion from 2015 to 2017. MISO was unable to comment by publication time on how much uneconomic commitments may have cost in their 2017-2019 analysis.

Self-committing resources is defended by utilities as a necessary practice to avoid high shutoff and startup costs, particularly for less flexible resources like coal, which aren't able to cycle on and off easily. The problem comes when self-committed units are dispatched to the market uneconomically, bumping other, cheaper resources out of line.

"The vast majority of all self-committed coal generation in MISO is actually dispatched economically — meaning it is the lowest-cost resource option that MISO markets have available at the time to serve load," MISO noted in its report.

UCS, Sierra Club and other groups have always agreed with this, said Daniel. The larger issue is what the plants that are operating uneconomically are costing ratepayers.

"It's not that all coal plants are uneconomically self-committing all the time, it's that some coal plants are uneconomically [self-committing] all the time," Daniel said. "The vast majority of losses are concentrated on a handful of bad actors. And ... the customers for those bad actors end up paying the price."

The problematic facilities tend to be operated by vertically-integrated utilities who are able to recover market losses incurred by these plants through ratepayers, Daniel noted. Previous research has found the issue to be almost exclusively contained within rate-regulated utilities.

not limited to coal plants. MISO also found in its recent report that 33% of gas-fired power plants in the MISO market were self-scheduled during the month of March and 15% of those units were not economically dispatched, according to MISO.

"I was genuinely surprised by that," said Daniel. "This just further proves that this is not an issue about needing a multi day market, or needing more flexibility, or needing something else. It's just that utilities aren't responding to the price signal of the market."

Fisher, Daniel and others have been pushing regulators to examine these practices more closely to ensure utilities aren't recovering costs they could have avoided by operating their facilities more economically.

Xcel Energy found that electing to economically dispatch its units more frequently rather than self-commit could save ratepayers billions of dollars. And Indiana regulators have opened up a sub-docket to examine the scheduling practices of Duke Energy Indiana more closely.

"Right now, there's almost 30 million unemployed Americans. One in three Americans struggle to pay their electric bills," said Daniel. "Now, more than ever, utilities should be taking advantage of low cost electricity on the open market and state commissions should be carefully scrutinizing cost recovery during this time."

Correction: Utilities in the MISO market rather than the market itself have been under increased regulatory scrutiny.

MISO also found that 88% of coal plants in its market are dispatched through self-scheduling. That means the vast majority of plants are operating out of merit order, which can incur severe losses over shorter periods of time, Jeremy Fisher, senior strategy and technical advisor at the Sierra Club's environmental law program told Utility Dive.

For example, in March, MISO saw "record low" energy prices, meaning that it was difficult to operate at all without a loss, let alone operate higher-cost coal plants. But 89% of coal plants were still self-scheduled that month, according to MISO's numbers — 16% uneconomically.

"I think that MISO missed the point all together," Fisher said in an email. "It should be deeply concerned that there are coal plants committing out of merit. That large fraction of units at economic minimum can still deeply distort market prices."

"The time period really matters," said Daniel. Even if the same coal units are self-scheduling year over year, the difference of whether they're economically dispatched or not depends on how high or low market prices were during that period. That's why, for example, a coal unit could take substantial losses across a month or several-week period where market prices are low.

Joe Daniel @electronecon · May 5, 2020
Replying to @electronecon
Often they use "spot market proxy" costs to determine replac
costs even though they have a fuel contract at above-market
See my blog on the subject from last year.
blog.ucsusa.org/joseph-daniel/...
7/

For Some, Coal Contracts are, "Heads I Win, Tails You Lose."
There is a pervasive myth in the electric sector that the own
coal-fired power plants all sign long term contracts for coal.
blog.ucsusa.org

Joe Daniel
@electronecon

Also, take a look at this graph showing that uneconom
generation isn't a problem. That red bit isn't a problem
you serious? There isn't a single hour in march when th
wasn't uneconomic coal operating. That's millions of $'
customers' money! 8/

4:06 PM · May 5, 2020

24 See Joe Daniel's other Tweets

The Southwest Power Pool conducted a similar analysis in December that found self-scheduling practices were suppressing fuel prices by about 7%, or $2/MWh. It also noted the practice is

Company type

Consulting

Job function

Privacy policy

ANNUAL REPORT — 2019

OHIO VALLEY ELECTRIC CORPORATION

and subsidiary

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[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

ANNUAL REPORT — 2019

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STATE OF MICHIGAN
BEFORE THE 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 (2020)	U-20529 ALJ Dennis Mack

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Direct Testimony of
Jeremy I. Fisher, PhD

On Behalf of
Sierra Club

***** PUBLIC VERSION *****

May 11, 2020

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7. I&M NEITHER SOUGHT NOR RECEIVED APPROVAL TO EXTEND THE OVEC ICPA

Q When was I&M's request to extend the original OVEC ICPA from a termination date of 2006 to 2026 authorized by this Commission?

A It wasn't. The Company never sought authorization by this Commission to extend the ICPA in 2004, and the Commission never provided authorization for that extension.

Q When was I&M's request to again extend the OVEC ICPA from a termination date of 2026 to 2040 authorized by this Commission?

A It wasn't. Again the Company never sought authorization by this Commission to extend the ICPA to 2040 in 2011, and the Commission never provided authorization for that extension.

Q Did I&M or AEP seek authorization to extend the ICPA with any other Commissions?

A Yes. The ICPA itself states that Indiana Michigan Power Company filed the ICPA with, and sought consent or approval, from the Federal Energy Regulatory Commission ("FERC"), and filed the contract with the Indiana Utility Regulatory Commission ("IURC"), although it never sought approval from the Indiana Commission.[86] AEP subsidiary Appalachian Power Company ("APCo") filed the ICPA with both the Virginia and West Virginia Commissions, and required that approval by the Virginia State Corporation Commission for the contract to become valid. The Kentucky sponsoring utilities (Kentucky Utilities and Louisville Gas & Electric) sought pre-approval for the decision to enter into the OVEC contract.

In the recent rate case, Sierra Club asked I&M to identify the docket in which the Company sought approval from this Commission for its decision to sign or modify the ICPA. The Company responded:

[86] ICPA, Schedule 10.01(c), Indiana Michigan Power Company. Page 49.

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 3
CASE NO. U-20224

DATA REQUEST NO. 3-02-SIERRA CLUB

Request

For each month of 2019, provide the itemized monthly charge as calculated by OVEC and charged to the Company, “itemized” by the following:

a. energy charge,
b. demand charge,
c. transmission charge (if any),
d. minimum loading events costs (if any), and
e. costs of participation in an ISO/RTO (if any).

Response

Please see “SC 3-02 Attachment_1.xlsx” for the requested information.

Preparer
Stegall

Indiana Michigan Power Company
OVEC Billing Data
Calendar Year 2019

	MWh Sold	Energy Charge	Demand Charge	Transmission Charge	PJM Expenses/ Fees	Total Bill
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
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

MEC-8C

CONFIDENTIAL EXHIBIT

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 1
CASE NO. U-20529 (2020 PSCR PLAN)

DATA REQUEST NO. 1-11 SC

Request

For each month since January 1, 2015, with respect to the Company's share of the energy, capacity, and ancillary services of the OVEC Units, provide the following, and label responses as "whole plant," "ownership" or "contractual" share as per instructions, above:

a. by month (or year if monthly data is not available) total energy produced (in MWh) and market revenue earned (in dollars) by the Company through sale of its share into PJM markets;

b. by year total capacity provided (in MW) and capacity market revenue earned (in dollars) by the Company through sale of its share into PJM markets;

c. by year total ancillary market revenue earned (in dollars) by the Company through sale of its share into PJM markets (if any);

d. For any month in which the Company took energy and/or capacity from the OVEC Units but did not sell all of such energy and/or capacity into the PJM markets, describe how such energy and/or capacity was used and the amount(s) for such uses.

Response

I&M objects to the request on the grounds and to the extent the request seeks information that is outside the scope of this proceeding, outside the PSCR forecast period and not reasonably calculated to lead to the discovery of relevant or admissible evidence. I&M further objects to the Request to the extent it seeks an analysis, calculation, or compilation which has not already been performed and which I&M objects to performing. In support of these objections, I&M states that the requested data prior to May 2016 is not in the Company's care, custody or control.

Without waiving these objections, I&M states:

a. Please see "SC 1-11 Attachment_1.xlsx" for the requested data.

b. The Company participates in a Power Coordination Agreement with AEP's other operating companies in PJM (Appalachian Power Co., Kentucky Power Co. and Wheeling Power Co.). Capacity in excess of the four companies' joint FRR obligations can be sold into the capacity auction and the revenues are allocated based on individual operating company capacity length. As a result, providing unit specific information on

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 1
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sales would not be meaningful since any of the four companies' resources could be used towards making the sale in the auction.

c. Please see “SC 1-11 Attachment_1.xlsx” for the requested data.

d. Not applicable.

As to Objection
Counsel

Preparer
Allen

As reported by PJM

	Energy Revenues SC 1-11 Pt. a	Ancillary Revenue SC 1-11 Pt. c
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
	$104,407,586.71	$103,427.08

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 3
CASE NO. U-20224

DATA REQUEST NO. 3-04-SIERRA CLUB

Request

For each month of 2019, provide the monthly energy received (in MWh) and capacity value of the OVEC Units to the Company. As to capacity, provide the amount of OVEC capacity relied on by the Company to meet its FRR obligations during each month of 2019.

Response

The energy values requested have been provided in the Company's response to SC 3-02. In 2019, OVEC contributed 174.0 MW of ICAP capacity towards the Company's FRR obligation for January through May 2019 and 174.3 MW of ICAP capacity for June through December 2019.

Preparer
Stegall

INTEGRATED RESOURCE PLANNING REPORT

TO THE

INDIANA UTILITY REGULATORY COMMISSION

Submitted Pursuant to

Commission Rule 170 IAC 4-7

July 1, 2019

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4.7.4.4 Battery Storage

The modeling of Battery Storage as a Peaking resource option is becoming a more common occurrence in IRPs. In recent years Lithium-ion battery technology has emerged as the fastest growing platform for stationary storage applications. The Battery Storage resource that was modeled in this IRP is a Lithium-ion storage technology and it has a nameplate rating of 10MW and 40MWh, with a round trip efficiency of 83%. See Figure 24 for the forecasted installed cost of this resource. To develop this resource, AEP's Generation Engineering Services considered a wide range of sources including: the DOE/EPRI 2015 Electricity Storage Handbook in Collaboration with the National Rural Electric Cooperative Association (NRECA), EPRI, BNEF and battery storage equipment suppliers. The storage resource characteristics and cost were updated in early 2019.

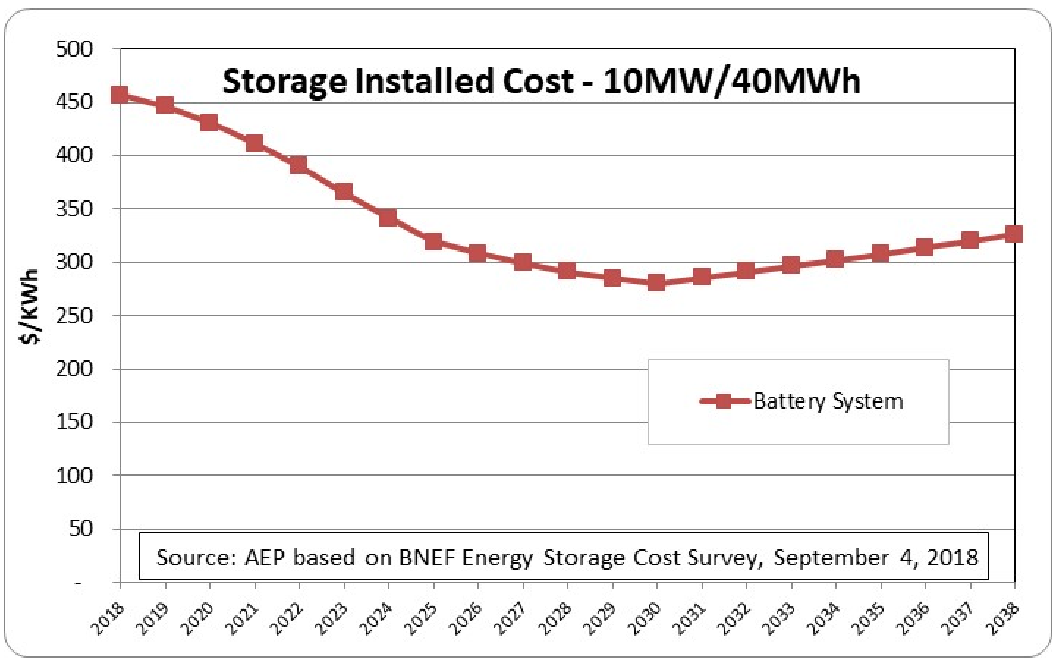

Figure 24. Energy Storage Installed Cost

4.7.5 Short-Term Market Purchase (STMP)

Short-Term Market Purchase (STMP) alternative resources were made available to the model for selection during the development of the optimal plans. This resource is assumed to have no energy associated with it, a contract term of one year and 1,000MW can be added annually. The pricing of these purchases is based on the PJM Capacity Prices shown in Figure

19. The purpose of adding this resource was to allow the model an option to include a short-term capacity commitment as opposed to building a long-term capacity resource.

4.7.6 Renewable Alternatives

Renewable generation alternatives use energy sources that are either naturally occurring (wind, solar, hydro or geothermal), or are sourced from a by-product or waste-product of another process (biomass or landfill gas). In the past, on a national level development of these resources has been driven primarily as the result of renewable portfolio requirements. That is not universally true now as advancements in both solar photovoltaics and wind turbine manufacturing have reduced both installed and ongoing costs.

At this time within the industry, renewable energy resources, because of their intermittent nature, provide more energy value than capacity value. For this IRP, the overall threshold for intermittent resource additions are 30% of I&M's energy demand for wind and 15% for solar. This assumes that the RTO and other key stakeholders will advance the understanding, forecasting and management of intermittent resources, ultimately supporting a higher penetration level and capacity planning values.

4.7.6.1 Solar

4.7.6.1.1 Large-Scale Solar

Solar power comes in two forms to produce electricity: concentrating and photovoltaics. Concentrating solar — which heats a working fluid to temperatures sufficient to generate steam to power a turbine — produces electricity on a large scale and is similar to traditional centralized supply assets in that respect. Photovoltaics can more easily be distributed throughout the grid and are a scalable resource that, for example, can be as small as a few kilowatts or as large as 500MW. This IRP assumes its solar resources will be photovoltaic.

The cost of large-, or utility-scale, solar projects has declined in recent years and is expected to continue to decline through 2023 (see Figure 25). This has been mostly a result of reduced panel prices that have resulted from manufacturing efficiencies spurred by accelerating penetration of solar energy in Europe, Japan, and California. With the trend firmly established, SPP Southwest Power Pool

SELF-COMMITMENTS IN SPP'S DAY-AHEAD MARKET

SPP continually works toward a level of self-commitments in its markets that appropriately balances reliability and economic considerations, and finds that nearly all self-committed energy in its markets are already the most economic option.

Southwest Power Pool (SPP) has evaluated both reliability and economic aspects of self-committed resources. SPP does not advocate for any particular market participant, generator or generator-type but instead dispatches least-cost generation available and as needed to maintain reliability. Participation in SPP's market is voluntary. Market participants may choose whether to offer a generating unit into the market or self-commit. Self-committed units are "price-takers" that commit to run no matter the price at which the market compensates them for electricity sold.

RELIABILITY & UNCERTAINTY

Resources requiring long lead-time start notices represent the majority of self-committed capacity in SPP. They offer a high availability factor and are designed to generate for long periods with little downtime. Frequently cycling them on and off may improve marginal energy costs but also poses challenges.

A report from the U.S. Department of Energy's National Energy Technology Laboratory[1] estimates an increase of approximately 10% in total fixed operation and maintenance costs when increasing the cycling of long lead-time coal units. These units consume a large amount of fuel that is mostly wasted during the startup period, so the more frequently they are cycled off and back on, the more fuel is wasted.

Frequent cycling of these resources may also degrade the bulk power system's reliability. Repeatedly heating and cooling components shortens their life span. This increases maintenance and capital costs associated with these units' operation and requires more downtime for repairs. Because these units play a critical role in system reliability, significant outages and derates could reduce reliability of the grid.

As the expansion of wind and solar generation increases in our footprint, so does uncertainty over the availability of our generation supply in real time. The result is that an increase in variable energy resources requires us to keep more long lead-time and fast-start units online to serve in instances where wind or solar resources suddenly deviate from forecast levels. Fast-start gas units with ramping capability and long lead-time generation both play a critical role in maintaining reliability during such periods. SPP is developing a fast-start market product to compensate generation for its availability to produce energy.

Example: SPP set a wind-peak record of 17,861 megawatts (MW) on Dec. 11, 2019. Less than 21 hours later, wind output bottomed out at just 1,745 MW. This 16,116 MW downward swing in less than a day required SPP's market to commit the equivalent of approximately 32 conventional generators in a matter of hours to cover the deficit. Some of these units take up to two days to produce energy.

[1] National Energy Technology Laboratory, Impact of Load Following on the Economics of Existing Coal-Fired Power Plant Operations, US Department of Energy, 2015

ECONOMICS

SPP analyzed the impact of committing resources that had been self-committed, assessing six scenarios that included high and low summer and winter peak loads, high and low daily overall production costs and significant variations in wind. The results indicated small increases in marginal energy costs (Table 1) and small reductions in overall production costs (Table 2) when all self-committed units were treated as though they were committed by the market. Energy and no-load production costs slightly decreased, while startup costs for analyzed periods slightly increased.

Table 1: Average marginal energy cost (MCE) in $1000s

STUDY WEEK	BASE	REMOVED SELFS
Aug. 4-10, 2019	$27.91	$29.44
Sept. 1-7, 2019	$25.79	$28.04
Oct. 20-26, 2019	$17.27	$20.19
Nov. 10-16	$24.98	$26.15
Feb. 9-15, 2020	$19.73	$21.39
April 26-May 2, 2020	$12.93	$14.49
All	$21.44	$23.28

SPP's analysis found that in all six scenarios, 85-95% of self-committed generation was committed and dispatched economically when converted to market-offered status. These results are promising and indicate that while improvements can be made, the majority of self-committed MWs in SPP are already economic. On average, only 10% of self-committed generation would not have been chosen for commitment and dispatched on a least-cost basis.

CURRENT DEVELOPMENT AND VOLUNTARY CONSIDERATIONS

In its first six years of operation, SPP's Integrated Marketplace has seen steady reductions of self-committed generation, from 70% in 2015 to 50% this year, according to the SPP Market Monitoring Unit's (MMU) December 2019 report, "Self-committing in SPP Markets: Overview, impacts and recommendations."

Despite this trend, self-commitments will likely continue to exist at some level. SPP's July 23, 2019, "Holistic Integrated Tariff Team (HITT) Report" recommends development of a multiday economic assessment to enable more cost-effective market-commitment decisions by SPP market participants. The SPP MMU's December 2019 report similarly recommends SPP and stakeholders reduce the incidence of self-commitments by adding an additional day to the market optimization period.

Even with multiday optimization, there are many reasons a resource might still self-commit. These include federal and state regulatory exemptions, testing, weather, fuel contracts and operational limitations such as long lead times, long minimum run times and high startup costs. SPP and the SPP MMU have discussed the possibility of modeling these restrictions in the resource offer.

SPP is developing a market design enhancement to include a multiday commitment and pricing forecast that will further improve the unit-commitment process. This and other market enhancements will represent a step toward assessing changes in the voluntary nature of asset owners' decisions to market-commit their resources. These incremental optimizations of SPP's Integrated Marketplace will reinforce the balance between economics and system reliability.

Table 2: Weekly change in day-ahead resource costs (in $1000s)

STUDY WEEK	ENERGY COSTS	START-UP COSTS	NO-LOAD COSTS
Aug. 4-10, 2019	$35	$261	($83)
Sept. 1-7, 2019	($1,064)	$148	$86
Oct. 20-26, 2019	($1,829)	$114	($191)
Nov. 10-16, 2019	($890)	($10)	($537)
Feb. 9-15, 2020	($1,340)	$123	($140)
Apr. 26-May 2, 2020	($841)	($65)	($172)
TOTAL	($5,927)	$571	($1,037)

Schedule C1

Michigan Public Service Commission
Indiana Michigan Power Company
Adjusted Net Operating Income
For the Historical Year Ended December 31, 2018

Case No.: U-20359
Exhibit No.: A-3
Schedule: C-1
Page: 1 of 1
Witness: T.H. Ross
T.A. Caudill

Line No.	(a) Description	(b) Source for Column (c)	(c) Total Company Net Operating Income $000	(d) Michigan Jurisdictional Net Operating Income $000
1	**Operating Revenues**	Exh. A-3, Sch C-3, line 7	2,284,142	371,408
2				
3	**Operating Expenses**			
4	Fuel and Purchased Power Expense	Exh. A-3, Sch C-4, line 4	753,436	105,063
5	Operating and Maintenance Expense	Exh. A-3, Sch C-5, line 59	751,945	132,393
6	Depreciation and Amortization Expense	Exh. A-3, Sch C-6, line 7	293,091	49,004
7	Taxes Other than Income Taxes	Exh. A-3, Sch C-3, line 7	95,184	12,313
8	Income Taxes	Exh. IM-23, 24 & 25	30,036	9,773
9	**Total Operating Expenses**		1,923,692	308,546
10				
11	**AFUDC**	Exh. A-3, Sch C-11 line 11	19,283	2,827
12				
13	**Net Operating Income**		379,733	65,689
14				
15	**Operating Income Adjustments**			
16	Perbook Revenue Provision for Refund		21,612	Incl. above
17	Rockport Test Energy, Pollution Control Accumulated Depreciation to Michigan Basis	WP-THR-1	(1,111)	Incl. above
18	Adjustment for Michigan Basis Depreciation Expense	WP-THR-2	(3,749)	Incl. above
19	Rockport DSI to Michigan Basis	WP-THR-3	(131)	Incl. above
20	Rockport Unit 1 SCR to Michigan Basis	WP-THR-3	(291)	Incl. above
21	Cook LCM to Michigan Basis	WP-THR-3	(1,112)	Incl. above
22	Rockport Unit 1 Pollution Control AFUDC Treatment	Exh. A-3, Sch C-11, line 9	(947)	Incl. above
23	Adjust Income for Other Taxes and Income Taxes	Exh. A-3, Sch C-7, C-8, C-9, C-10	(4,109)	Incl. above
24	**Total Operating Income Adjustments**		10,162	-
25				
26	**Adjusted Net Operating Income**		389,895	65,689

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 3
CASE NO. U-20224

DATA REQUEST NO. 3-11-SIERRA CLUB

Request

Regarding I&M's power purchase agreement with OVEC:

a. Please provide a copy of the current Inter-Company Power Agreement between I&M and OVEC.

b. Indicate whether I&M has researched, evaluated, or discussed either internally or publicly, the steps, process, and timeline required to exit the OVEC contract.

i. If yes, please detail I&M's understanding of the steps, process and timeline to exit the OVEC contract.

ii. If yes, please provide all written communications, reports, and presentations regarding I&M's discussion of exiting the OVEC contract,

iii. If no, please explain why no research or discussion has been had of existing the OVEC contract.

c. Indicate whether I&M has taken any steps to exit the contract with OVEC.

i. If yes, please detail the steps that I&M has taken.

ii. If no, please explain why I&M has not taken steps to exist the contract.

d. Indicate whether I&M has performed any analysis during 2019 on the economics of staying in the contract and purchasing powering from OVEC relative to exiting the contract and purchasing energy from the PJM market.

i. If yes, please provide all such analysis performed during 2019.

ii. If no, please indicate why no analysis has been performed.

Response

a. See "SC 3-11 Attachment_1.pdf" for the requested document.

b. I&M objects to subpart (b) of this request on the grounds and to the extent the request seeks information that is outside the scope of this proceeding and, therefore, is not reasonably calculated to lead to the discovery of relevant or admissible evidence.. I&M further objects to subpart (b) this request on the grounds and to the extent the request calls for disclosure of legal strategy and requires speculation by I&M to determine a future course of action that is dependent upon a variety of future events that are unknown. Last, I&M objects to subpart (b) of this request to the extent it seeks information that is subject to the attorney-client, work product, settlement negotiation or other applicable privileges.

INDIANA MICHIGAN POWER COMPANY
SIERRA CLUB
DATA REQUEST SET NO. 3
CASE NO. U-20224

c. I&M objects to subpart (c) of this request on the grounds and to the extent the request is overly broad and unduly burdensome, particularly to the extent that the question requests "any steps." I&M objects to subpart (c) of this request on the grounds and to the extent the request seeks information that is outside the scope of this proceeding and, therefore, is not reasonably calculated to lead to the discovery of relevant or admissible evidence.. I&M further objects to subpart (b) this request on the grounds and to the extent the request calls for disclosure of legal strategy and requires speculation by I&M to determine a future course of action that is dependent upon a variety of future events that are unknown. Last, I&M objects to subpart (b) of this request to the extent it seeks information that is subject to the attorney-client, work product, settlement negotiation or other applicable privileges.

d. I&M performed no such analysis in 2019.

i. Not applicable.

ii. I&M is contractually committed to the OVEC purchase, which purchase is part of I&M's diversified resource portfolio used to meet the capacity and energy needs of customers.

<u>As to objection</u>
Counsel

<u>Preparer</u>
Allen

Execution Copy

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

DATED AS OF SEPTEMBER 10, 2010

AMONG

OHIO VALLEY ELECTRIC CORPORATION,
ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
APPALACHIAN POWER COMPANY,
BUCKEYE POWER GENERATING, LLC,
COLUMBUS SOUTHERN POWER COMPANY,
THE DAYTON POWER AND LIGHT COMPANY,
DUKE ENERGY OHIO, INC.,
FIRSTENERGY GENERATION CORP.,
INDIANA MICHIGAN POWER COMPANY,
KENTUCKY UTILITIES COMPANY,
LOUISVILLE GAS AND ELECTRIC COMPANY,
MONONGAHELA POWER COMPANY,
OHIO POWER COMPANY,
PENINSULA GENERATION COOPERATIVE, and
SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

THIS AGREEMENT, dated as of September 10, 2010 (the "Agreement"), by and among OHIO VALLEY ELECTRIC CORPORATION (herein called OVEC), ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C. (herein called Allegheny), APPALACHIAN POWER COMPANY (herein called Appalachian), BUCKEYE POWER GENERATING, LLC (herein called Buckeye), COLUMBUS SOUTHERN POWER COMPANY (herein called Columbus), THE DAYTON POWER AND LIGHT COMPANY (herein called Dayton), DUKE ENERGY OHIO, INC. (formerly known as The Cincinnati Gas & Electric Company and herein called Duke Ohio), FIRSTENERGY GENERATION CORP. (herein called FirstEnergy), INDIANA MICHIGAN POWER COMPANY (herein called Indiana), KENTUCKY UTILITIES COMPANY (herein called Kentucky), LOUISVILLE GAS AND ELECTRIC COMPANY (herein called Louisville), MONONGAHELA POWER COMPANY (herein called Monongahela), OHIO POWER COMPANY (herein called Ohio Power), PENINSULA GENERATION COOPERATIVE (herein called Peninsula), and SOUTHERN INDIANA GAS AND ELECTRIC COMPANY (herein called Southern Indiana, and all of the foregoing, other than OVEC, being herein sometimes collectively referred to as the Sponsoring Companies and individually as a Sponsoring Company) hereby amends and restates in its entirety, the Inter-Company Power Agreement dated as of March 13, 2006, as amended by Modification No. 1, dated as of March 13, 2006 (herein called the Current Agreement), by and among OVEC and the Sponsoring Companies.

WITNESSETH THAT:

WHEREAS, the Current Agreement amended and restated the original Inter-Company Power Agreement, dated as of July 10, 1953, as amended by Modification No. 1, dated as of June 3, 1966; Modification No. 2, dated as of January 7, 1967; Modification No. 3, dated as of November 15, 1967; Modification No. 4, dated as of November 5, 1975; Modification No. 5, dated as of September 1, 1979; Modification No. 6, dated as of August 1, 1981; Modification No. 7, dated as of January 15, 1992; Modification No. 8, dated as of January 19, 1994; Modification No. 9, dated as of August 17, 1995; Modification No. 10, dated as of January 1, 1998; Modification No. 11, dated as of April 1, 1999; Modification No. 12, dated as of November 1, 1999; Modification No. 13, dated as of May 24, 2000; Modification No. 14, dated as of April 1, 2001; and Modification No. 15, dated as of April 30, 2004 (together, herein called the Original Agreement); and

WHEREAS, OVEC designed, purchased, and constructed, and continues to operate and maintain two steam-electric generating stations, one station (herein called Ohio Station) consisting of five turbo-generators and all other necessary equipment, at a location on the Ohio River near Cheshire, Ohio, and the other station (herein called Indiana Station) consisting of six turbogenerators and all other necessary equipment, at a location on the Ohio River near Madison, Indiana, (the Ohio Station and the Indiana Station being herein called the Project Generating Stations); and

WHEREAS, OVEC also designed, purchased, and constructed, and continues to operate and maintain necessary transmission and general plant facilities (herein called the Project Transmission Facilities) and OVEC established or cause to be established interconnections between the Project Generating Stations and the systems of certain of the Sponsoring Companies; and

WHEREAS, OVEC entered into an agreement, attached hereto as Exhibit A, with Indiana-Kentucky Electric Corporation (herein called IKEC), a corporation organized under the laws of the State of Indiana as a wholly owned subsidiary corporation of OVEC, which has been amended and restated as of the date of this Agreement and embodies the terms and conditions for the ownership and operation by IKEC of the Indiana Station and such portion of the Project Transmission Facilities which are to be owned and operated by it; and

WHEREAS, transmission facilities were constructed by certain of the Sponsoring Companies to interconnect the systems of such Sponsoring Companies, directly or indirectly, with the Project Generating Stations and/or the Project Transmission Facilities, and the Sponsoring Companies have agreed to pay for Available Power, as hereinafter defined, as may be available at the Project Generating Stations; and

WHEREAS, the parties hereto desire to amend and restate in their entirety, the Current Agreement to define the terms and conditions governing the rights of the Sponsoring Companies to receive Available Power from the Project Generating Stations and the obligations of the Sponsoring Companies to pay therefor.

NOW, THEREFORE, the parties hereto agree with each other as follows:

ARTICLE 1

DEFINITIONS

1.01. For the purposes of this Agreement, the following terms, wherever used herein, shall have the following meanings:

1.011 "Affiliate" means, with respect to a specified person, any other person that directly or indirectly through one or more intermediaries controls, is controlled by, or is under common control with, such specified person; provided that "control" for these purposes means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting securities, by contract or otherwise.

1.012 "Arbitration Board" has the meaning set forth in Section 9.10.

1.013 "Available Energy" of the Project Generating Stations means the energy associated with Available Power.

1.014 "Available Power" of the Project Generating Stations at any particular time means the total net kilowatts at the 345-kV busses of the Project Generating Stations which Corporation in its sole discretion will determine that the Project Generating Stations will be capable of safely delivering under conditions then prevailing, including all conditions affecting capability.

1.015 "Corporation" means OVEC, IKEC, and all other subsidiary corporations of OVEC.

1.016 "Decommissioning and Demolition Obligation" has the meaning set forth in Section 5.03(f) hereof.

1.017 "Effective Date" means September 10, 2010, or to the extent necessary, such later date on which Corporation notifies the Sponsoring Companies that all conditions to effectiveness, including all required waiting periods and all required regulatory acceptances or approvals, of this Agreement have been satisfied in form and substance satisfactory to the Corporation.

1.018 "Election Period" has the meaning set forth in Section 9.183(a) hereof.

1.019 "Minimum Generating Unit Output" means 80 MW (net) for each of the Corporation's generation units; provided that such "Minimum Generating Unit Output" shall be confirmed from time to time by operating tests on the Corporation's generation units and shall be adjusted by the Operating Committee as appropriate following such tests.

1.0110 "Minimum Loading Event" means a period of time during which one or more of the Corporation's generation units are operating at below the Minimum Generating Output as a result of the Sponsoring Companies' failure to schedule and take delivery of sufficient Available Energy.

1.0111 "Minimum Loading Event Costs" means the sum of the following costs caused by one or more Minimum Loading Events: (i) the actual costs of any of the Corporation's generating units burning fuel oil; and (ii) the estimated actual additional costs to the Corporation resulting from Minimum Loading Events, including without limitation the incremental costs of additional emissions allowances, reflected in the schedule of charges prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedule may be adjusted from time to time as necessary by the Operating Committee.

1.0112 "Month" means a calendar month.

1.0113 "Nominal Power Available" means an individual Sponsoring Company's Power Participation Ratio share of the Corporation's current estimate of the maximum amount of Available Power available for delivery at any given time.

1.0114 "Offer Notice" means the notice required to be given to the other Sponsoring Companies by a Transferring Sponsor offering to sell all or a portion of such Transferring Sponsor's rights, title and interests in, and obligations under this Agreement. At a minimum, the Offer Notice shall be in writing and shall contain (i) the rights, title and interests in, and obligations under this Agreement that the Transferring Sponsor proposes to Transfer; and (ii) the cash purchase price and any other material terms and conditions of such proposed transfer. An Offer Notice may not contain terms or conditions requiring the purchase of any non-OVEC interests.

1.0115 "Permitted Assignee" means a person that is (a) a Sponsoring Company or its Affiliate whose long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, has a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if the proposed assignee's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such assignee's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); or (b) a Sponsoring Company or its Affiliate that does not meet the criteria in subsection (a) above, if the Sponsoring Company or its Affiliate that is assigning its rights, title and interests in, and obligations under, this Agreement agrees in writing (in form and substance satisfactory to Corporation) to remain obligated to satisfy all of the obligations related to the assigned rights, title and interests to the extent such obligations are not satisfied by the assignee of such rights, title and interests; provided that, in no event shall a person be deemed a "Permitted Assignee" if counsel for the Corporation reasonably determines that the assignment of the rights, title or interests in, or obligations under, this Agreement to such person could cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer.

1.0116 "Postretirement Benefit Obligation" has the meaning set forth in Section 5.03(e) hereof.

1.0117 "Power Participation Ratio" as applied to each of the Sponsoring Companies refers to the percentage set forth opposite its respective name in the tabulation below:

Company	Power Participation Ratio—Percent

Allegheny	3.01
Appalachian	15.69
Buckeye	18.00
Columbus	4.44
Dayton	4.90
Duke Ohio	9.00
FirstEnergy	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	0.49
Ohio Power	15.49
Peninsula	6.65
Southern Indiana	1.50
Total	100.0

1.0118 "Tariff" means the open access transmission tariff of the Corporation, as amended from time to time, or any successor tariff, as accepted by the Federal Energy Regulatory Commission or any successor agency.

1.0119 "Third Party" means any person other than a Sponsoring Company or its Affiliate.

1.0120 "Total Minimum Generating Output" means the product of the Minimum Generating Unit Output times the number of the Corporation's generation units available for service at that time.

1.0121 "Transferring Sponsor" has the meaning set forth in Section 9.183(a) hereof.

1.0122 "Uniform System of Accounts" means the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission as in effect on January 1, 2004.

ARTICLE 2

TRANSMISSION AGREEMENT AND FACILITIES

2.01. *Transmission Agreement.* The Corporation shall enter into a transmission service agreement under the Tariff, and the Corporation shall reserve and schedule transmission service, ancillary services and other transmission-related services in accordance with the Tariff to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement.

2.02. *Limited Burdening of Corporation's Transmission Facilities.* Transmission facilities owned by the Corporation, including the Project Transmission Facilities, shall not be burdened by power and energy flows of any Sponsoring Company to an extent which would impair or prevent the transmission of Available Power.

ARTICLE 3

[RESERVED]

ARTICLE 4

AVAILABLE POWER SUPPLY

4.01. *Operation of Project Generating Stations.* Corporation shall operate and maintain the Project Generating Stations in a manner consistent with safe, prudent, and efficient operating practice so that the Available Power available from said stations shall be at the highest practicable level attainable consistent with OVEC's obligations under Reliability*First* Reliability Standard BAL-002-RFC throughout the term of this Agreement.

4.02. *Available Power Entitlement.* The Sponsoring Companies collectively shall be entitled to take from Corporation and Corporation shall be obligated to supply to the Sponsoring Companies any and all Available Power and Available Energy pursuant to the provisions of this Agreement. Each Sponsoring Company's Available Power Entitlement hereunder shall be its Power Participation Ratio, as defined in *subsection* 1.0117, of Available Power.

4.03. *Available Energy.* Corporation shall make Available Energy available to each Sponsoring Company in proportion to said Sponsoring Company's Power Participation Ratio. No Sponsoring Company, however, shall be obligated to avail itself of any Available Energy. Available Energy shall be scheduled and taken by the Sponsoring Companies in accordance with the following procedures:

> 4.031 Each Sponsoring Company shall schedule the delivery of all or any portion (in whole MW increments) of its entitlement to Available Energy in accordance with scheduling procedures established by the Operating Committee from time to time.
>
> 4.032 In the event that any Sponsoring Company does not schedule the delivery of all of its Power Participation Ratio share of Available Energy, then each such other Sponsoring Company may schedule the delivery of all or any portion (in whole MW increments) of any such unscheduled share of Available Energy (through successive allotments if necessary) in proportion to their Power Participation Ratios.

4.033 Notwithstanding any Available Energy schedules made in accordance with this Section 4.03 and the applicable scheduling procedures, (i) the Corporation shall adjust all schedules to the extent that the Corporation's actual generation output is less than or more than the expected Nominal Power Available to all Sponsoring Companies, or to the extent that the Corporation is unable to obtain sufficient transmission service under the Tariff for the delivery of all scheduled Available Energy; and (ii) immediately following a Minimum Loading Event, any Sponsoring Company causing (in whole or part) such Minimum Loading Event shall have its Available Energy schedules increased after the schedules of the Sponsoring Companies not causing such Minimum Load Event, in accordance with the estimated ramp rates associated with the shutdown and start-up of the Corporation's generation units as reflected in the schedules prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedules may be adjusted from time to time as necessary by the Operating Committee.

4.034 Each Sponsoring Company availing itself of Available Energy shall be entitled to an amount of energy (herein called billing kilowatt-hours of Available Energy) equal to its portion, determined as provided in this Section 4.03, of the total Available Energy after deducting therefrom such Sponsoring Company's proportionate share, as defined in this Section 4.03, of all losses as determined in accordance with the Tariff incurred in transmitting the total of such Available Energy from the 345-kV busses of the Project Generating Stations to the applicable delivery points, as scheduled pursuant to Section 9.01, of all Sponsoring Companies availing themselves of Available Energy. The proportionate share of all such losses that shall be so deducted from such Sponsoring Company's portion of Available Energy shall be equal to all such losses multiplied by the ratio of such portion of Available Energy to the total of such Available Energy. Each Sponsoring Company shall have the right, pursuant to this Section 4.03, to avail itself of Available Energy for the purpose of meeting the loads of its own system and/or of supplying energy to other systems in accordance with agreements, other than this Agreement, to which such Sponsoring Company is a party.

4.035 To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then such one or more Sponsoring Companies shall be assessed charges for any Minimum Loading Event Costs in accordance with Section 5.05.

ARTICLE 5

CHARGES FOR AVAILABLE POWER AND MINIMUM LOADING EVENT COSTS

5.01. *Total Monthly Charge.* The amount to be paid to Corporation each month by the Sponsoring Companies for Available Power and Available Energy supplied under this

Agreement shall consist of the sum of an energy charge, a demand charge, and a transmission charge, all determined as set forth in this *Article* 5.

5.02. *Energy Charge.* The energy charge to be paid each month by the Sponsoring Companies for Available Energy shall be determined by Corporation as follows:

5.021 Determine the aggregate of all expenses for fuel incurred in the operation of the Project Generating Stations, in accordance with Account 501 (Fuel), Account 506.5 (Variable Reagent Costs Associated With Pollution Control Facilities) and 509 (Allowances) of the Uniform System of Accounts.

5.022 Determine for such month the difference between the total cost of fuel as described in subsection 5.021 above and the total cost of fuel included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section 8.03. For the purposes hereof the difference so determined shall be the fuel cost allocable for such month to the total kilowatt-hours of energy generated at the Project Generating Stations for the supply of Available Energy. For Available Energy availed of by the Sponsoring Companies, each Sponsoring Company shall pay Corporation for each such month an amount obtained by multiplying the ratio of the billing kilowatt-hours of such Available Energy availed of by such Sponsoring Company during such month to the aggregate of the billing kilowatt-hours of all Available Energy availed of by all Sponsoring Companies during such month times the total cost of fuel as described in this subsection 5.022 for such month.

5.03. *Demand Charge*. During the period commencing with the Effective Date and for the remainder of the term of this Agreement, demand charges payable by the Sponsoring Companies to Corporation shall be determined by the Corporation as provided below in this Section 5.03. Each Sponsoring Company's share of the aggregate demand charges shall be the percentage of such charges represented by its Power Participation Ratio.

The aggregate demand charge payable each month by the Sponsoring Companies to Corporation shall be equal to the total costs incurred for such month by Corporation resulting from its ownership, operation, and maintenance of the Project Generating Stations and Project Transmission Facilities determined as follows:

As soon as practicable after the close of each calendar month the following components of costs of Corporation (eliminating any duplication of costs which might otherwise be reflected among the corporate entities comprising Corporation) applicable for such month to the ownership, operation and maintenance of the Project Generating Stations and the Project Transmission Facilities, including additional facilities and/or spare parts (such as fuel processing plants, flue gas or waste product processing facilities, and facilities reasonably required to enable the Corporation to limit the emission of pollutants or the discharge of wastes in compliance with governmental requirements) and replacements necessary or desirable to keep the Project Generating Stations and the Project Transmission Facilities in a dependable and efficient operating condition, and any provision for any taxes that may be applicable to such charges, to be determined and recorded in the following manner:

(a) Component (A) shall consist of fixed charges made up of (i) the amounts of interest properly chargeable to Accounts 427, 430 and 431, less the amount thereof credited to Account 432, of the Uniform System of Accounts, including the interest component of any purchase price, interest, rental or other payment under an installment sale, loan, lease or similar agreement relating to the purchase, lease or acquisition by Corporation of additional facilities and replacements (whether or not such interest or other amounts have come due or are actually payable during such Month), (ii) the amounts of amortization of debt discount or premium and expenses properly chargeable to Accounts 428 and 429, and (iii) an amount equal to the sum of (I) the applicable amount of the debt amortization component for such month required to retire the total amount of indebtedness of Corporation issued and outstanding, (II) the amortization requirement for such month in respect of indebtedness of Corporation incurred in respect of additional facilities and replacements, and (III) to the extent not provided for pursuant to clause (II) of this clause (iii), an appropriate allowance for depreciation of additional facilities and replacements.

(b) Component (B) shall consist of the total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expense, etc., properly chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts (exclusive of Accounts 501, 509, 555, 911, 912, 913, 916, and 917 of the Uniform System of Accounts), minus the total of all non-fuel costs included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section 8.03, minus the total of all transmission charges payable to the Corporation for such month pursuant to Section 5.04, and plus any additional amounts which, after provision for all income taxes on such amounts (which shall be included in Component (C) below), shall equal any amounts paid or payable by Corporation as fines or penalties with respect to occasions where it is asserted that Corporation failed to comply with a law or regulation relating to the emission of pollutants or the discharge of wastes.

(c) Component (C) shall consist of the total expenses for taxes, including all taxes on income but excluding any federal income taxes arising from payments to Corporation under Component (D) below, and all operating or other costs or expenses, net of income, not included or specifically excluded in Components (A) or (B) above, including tax adjustments, regulatory adjustments, net losses for the disposition of property and other net costs or expenses associated with the operation of a utility.

(d) Component (D) shall consist of an amount equal to the product of $2.089 multiplied by the total number of shares of capital stock of the par value of $100 per share of Ohio Valley Electric Corporation which shall have been issued and which are outstanding on the last day of such month.

(e) Component (E) shall consist of an amount to be sufficient to pay the costs and other expenses relating to the establishment, maintenance and administration of life insurance, medical insurance and other postretirement benefits other than pensions attributable to the employment and employee service of active employees, retirees, or other employees, including without limitation any premiums due or expected to become due, as well as administrative fees and costs, such amounts being sufficient to provide payment with respect to all periods for which Corporation has committed or is otherwise obligated to make such payments, including amounts attributable to current employee service and any unamortized prior service cost, gain or loss attributable to prior service years ("Postretirement Benefit Obligation"); provided that, the amount payable for Postretirement Benefit Obligations during any month shall be determined by the Corporation based on, among other factors, the Statement of Financial Accounting Standards No. 106 (Employers' Accounting For Postretirement Benefits Other Than Pensions) and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Postretirement Benefit Obligation.

(f) Component (F) shall consist of an amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations, which amount shall include, without limitation the following costs (net of any salvage credits): the costs of demolishing the plants' building structures, disposal of non-salvageable materials, removal and disposal of insulating materials, removal and disposal of storage tanks and associated piping, disposal or removal of materials and supplies (including fuel oil and coal), grading, covering and reclaiming storage and disposal areas, disposing of ash in ash ponds to the extent required by regulatory authorities, undertaking corrective or remedial action required by regulatory authorities, and any other costs incurred in putting the facilities in a condition necessary to protect health or the environment or which are required by regulatory authorities, or which are incurred to fund continuing obligations to monitor or to correct environmental problems which result, or are later discovered to result, from the facilities' operation, closure or post-closure activities ("Decommissioning and Demolition Obligation") provided that, the amount payable for Decommissioning and Demolition Obligations during any month shall be calculated by Corporation based on, among other factors, the then-estimated useful life of the Project Generating Stations and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Decommissioning and Demolition Obligation, and provided further that, the Corporation shall recalculate the amount payable under this Component (F) for future months from time to time, but in no event later than five (5) years after the most recent calculation.

5.04. *Transmission Charge*. The transmission charges to be paid each month by the Sponsoring Companies shall be equal to the total costs incurred for such month by Corporation for the purchase of transmission service, ancillary services and other transmission-related services under the Tariff as reserved and scheduled by the Corporation to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement. Each Sponsoring Company's share of the aggregate transmission charges shall be the percentage of such charges represented by its Power Participation Ratio.

5.05. *Minimum Loading Event Costs*. To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then the sum of all Minimum Loading Event Costs relating to such Minimum Loading Event shall be charged to such Sponsoring Company or group of Sponsoring Companies that failed take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during such period, with such Minimum Loading Event Costs allocated among such Sponsoring Companies on a pro-rata basis in accordance with such Sponsoring Company's MWh share of the MWh reduction in the delivery of Available Energy causing any Minimum Loading Event. The applicable charges for Minimum Loading Event Costs as determined by the corporation in accordance with Section 5.05 shall be paid each month by the applicable Sponsoring Companies.

ARTICLE 6

Metering of Energy Supplied

6.01. *Measuring Instruments*. The parties hereto shall own and maintain such metering equipment as may be necessary to provide complete information regarding the delivery of power and energy to or for the account of any of the parties hereto; and the ownership and expense of such metering shall be in accordance with agreements among them. Each party will at its own expense make such periodic tests and inspections of its meters as may be necessary to maintain them at the highest practical commercial standard of accuracy and will advise all other interested parties hereto promptly of the results of any such test showing an inaccuracy of more than 1%. Each party will make additional tests of its meters at the request of any other interested party. Other interested parties shall be given notice of, and may have representatives present at, any test and inspection made by another party.

ARTICLE 7

COSTS OF REPLACEMENTS AND ADDITIONAL FACILITIES; PAYMENTS FOR EMPLOYEE BENEFITS; DECOMMISSIONING, SHUTDOWN, DEMOLITION AND CLOSING CHARGES

7.01. *Replacement Costs.* The Sponsoring Companies shall reimburse Corporation for the difference between (a) the total cost of replacements chargeable to property and plant made by Corporation during any month prior thereto (and not previously reimbursed) and (b) the amounts received by Corporation as proceeds of fire or other applicable insurance protection, or amounts recovered from third parties responsible for damages requiring replacement, plus provision for all taxes on income on such difference; provided that, to the extent that the Corporation arranges for the financing of any replacements, the payments due under this Section 7.01 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio. The term cost of replacements, as used herein, shall include all components of cost, plus removal expense, less salvage.

7.02. *Additional Facility Costs.* The Sponsoring Companies shall reimburse Corporation for the total cost of additional facilities and/or spare parts purchased and/or installed by Corporation during any month prior thereto (and not previously reimbursed), plus provision for all taxes on income on such costs; provided that, to the extent that the Corporation arranges for the financing of any additional facilities and/or spare parts, the payments due under this Section 7.02 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio.

7.03. *Payments for Employee Benefits.* Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Postretirement Benefit Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to fulfill its commitments or obligations with respect to both postemployment benefit obligations under the Statement of Financial Accounting Standards No. 112 and postretirement benefits other than pensions, as determined by Corporation with the aid of an actuary or actuaries selected by the Corporation based on the terms of the Corporation's then-applicable plans.

7.04. *Decommissioning, Shutdown, Demolition and Closing.* The Sponsoring Companies recognize that a part of the cost of supplying power to it under this Agreement is the amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations. Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Decommissioning and Demolition Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to complete the decommissioning, shutdown, demolition and closing of the Project Generating Stations, based on the Corporation's recalculation of the Decommissioning and Demolition Obligation in accordance with Section 5.03(f) of this Agreement no earlier than twelve (12) months before the effective date of termination of this Agreement.

ARTICLE 8

BILLING AND PAYMENT

8.01. *Available Power, and Replacement and Additional Facility Costs.* As soon as practicable after the end of each month Corporation shall render to each Sponsoring Company a statement of all Available Power and Available Energy supplied to or for the account of such Sponsoring Company during such month, specifying the amount due to the Corporation therefor, including any amounts for reimbursement for the cost of replacements and additional facilities and/or spare parts incurred during such month, pursuant to *Articles* 5 and 7 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case any factor entering into the computation of the amount due for Available Power and Available Energy cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made.

8.02. *Provisional Payments for Available Power.* The Sponsoring Companies shall, from time to time, at the request of the Corporation, make provisional semi-monthly payments for Available Power in amounts approximately equal to the estimated amounts payable for Available Power delivered by Corporation to the Sponsoring Companies during each semi-monthly period. As soon as practicable after the end of each semi-monthly period with respect to which Corporation has requested the Sponsoring Companies to make provisional semi-monthly payments for Available Power, Corporation shall render to each Sponsoring Company a separate statement indicating the amount payable by such Sponsoring Company for such semi-monthly period. Such Sponsoring Company shall make payment therefor promptly upon receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement and the amounts so paid by such Sponsoring Company shall be credited to the account of such Sponsoring Company with respect to future payments to be made pursuant to *Articles* 5 and 7 above by such Sponsoring Company to Corporation for Available Power.

8.03. *Minimum Loading Event Costs.* As soon as practicable after the end of each month, Corporation shall render to each Sponsoring Company a statement indicating any applicable charges for Minimum Loading Event Costs pursuant to Section 5.05 during such month, specifying the amount due to the Corporation therefor pursuant to *Article* 5 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case the computation of the amount due for Minimum Loading Event Costs cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made, and all payments shall be subject to subsequent adjustment.

8.04. *Unconditional Obligation to Pay Demand and Other Charges.* The obligation of each Sponsoring Company to pay its specified portion of the Demand Charge under Section 5.03, the Transmission Charge under Section 5.04, and all charges under *Article* 7 for any Month shall not be reduced irrespective of:

(a) whether or not any Available Power or Available Energy are supplied by the Corporation during such calendar month and whether or not any Available Power or Available Energy are accepted by any Sponsoring Company during such calendar month;

(b) the existence of any claim, set-off, defense, reduction, abatement or other right (other than irrevocable payment, performance, satisfaction or discharge in full) that such Sponsoring Company may have, or which may at any time be available to or be asserted by such Sponsoring Company, against the Corporation , any other Sponsoring Company, any creditor of the Corporation or any other Person (including, without limitation, arising as a result of any breach or alleged breach by either the Corporation, any other Sponsoring Company, any creditor of the Corporation or any other Person under this Agreement or any other agreement (whether or not related to the transactions contemplated by this Agreement or any other agreement) to which such party is a party); or

(c) the validity or enforceability against any other Sponsoring Company of this Agreement or any right or obligation hereunder (or any release or discharge thereof) at any time.

ARTICLE 9

GENERAL PROVISIONS

9.01. *Characteristics of Supply and Points of Delivery.* All power and energy delivered hereunder shall be 3-phase, 60-cycle, alternating current, at a nominal unregulated voltage designated for the point of delivery as described in this *Article* 9. Available Power and Available Energy to be delivered between Corporation and the Sponsoring Companies pursuant to this Agreement shall be delivered under the terms and conditions of the Tariff at the points, as scheduled by the Sponsoring Company in accordance with procedures established by the Operating Committee and in accordance with Section 9.02, where the transmission facilities of Corporation interconnect with the transmission facilities of any Sponsoring Company (or its successor or predecessor); provided that, to the extent that a joint and common market is established for the sale of power and energy by Sponsoring Companies within one or more of the regional transmission organizations or independent system operators approved by the Federal Energy Regulatory Commission in which the Sponsoring Companies are members or otherwise participate, then Corporation and the Sponsoring Companies shall take such action as reasonably necessary to permit the Sponsoring Companies to bid their entitlement to power and energy from Corporation into such market(s) in accordance with the procedures established for such market(s).

9.02. *Modification of Delivery Schedules Based on Available Transmission Capability.* To the extent that transmission capability available for the delivery of Available Power and Available Energy at any delivery point is less than the total amount of Available Power and Available Energy scheduled for delivery by the Sponsoring Companies at such delivery point in accordance with Section 9.01, then the following procedures shall apply and the Corporation and the applicable Sponsoring Companies shall modify their delivery schedules accordingly until the total amount of Available Power and Available Energy scheduled for delivery at such delivery point is equal to or less than the transmission capability available for the delivery of Available Power and Available Energy: (a) the transmission capability available for the delivery of Available Power and Available Energy at the following delivery points shall be allocated first on a pro rata basis (in whole MW increments) to the following Sponsoring Companies up to their Power Participation Ratio share of the total amount of Available Energy available to all Sponsoring Companies (and as applicable, further allocated among Sponsoring Companies entitled to allocation under this Section 9.02(a) in accordance with their Power Participation Ratios): (i) to Allegheny, Appalachian, Buckeye, Columbus, FirstEnergy, Indiana, Monongahela, Ohio Power and Peninsula (or their successors) for deliveries at the points of interconnection between the Corporation and Appalachian, Columbus, Indiana or Ohio Power, or their successors; (ii) to Duke Ohio (or its successor) for deliveries at the points of interconnection between the Corporation and Duke Ohio or its successor; (iii) to Dayton (or its successor) for deliveries at the points of interconnection between the Corporation and Dayton or its successor; and (iv) to Kentucky, Louisville and Southern Indiana (or their successors) for deliveries at the points of interconnection between the Corporation and Louisville or Kentucky, or their successors; and (b) any remaining transmission capability available for the delivery of

Available Power and Available Energy shall be allocated on a pro rata basis (in whole MW increments) to the Sponsoring Companies in accordance with their Power Participation Ratios.

9.03. *Operation and Maintenance of Systems Involved.* Corporation and the Sponsoring Companies shall operate their systems in parallel, directly or indirectly, except during emergencies that temporarily preclude parallel operation. The parties hereto agree to coordinate their operations to assure maximum continuity of service from the Project Generating Stations, and with relation thereto shall cooperate with one another in the establishment of schedules for maintenance and operation of equipment and shall cooperate in the coordination of relay protection, frequency control, and communication and telemetering systems. The parties shall build, maintain and operate their respective systems in such a manner as to minimize so far as practicable rapid fluctuations in energy flow among the systems. The parties shall cooperate with one another in the operation of reactive capacity so as to assure mutually satisfactory power factor conditions among themselves.

The parties hereto shall exercise due diligence and foresight in carrying out all matters related to the providing and operating of their respective power resources so as to minimize to the extent practicable deviations between actual and scheduled deliveries of power and energy among their systems. The parties hereto shall provide and/or install on their respective systems such communication, telemetering, frequency and/or tie-line control facilities essential to so minimizing such deviations; and shall fully cooperate with one another and with third parties (such third parties whose systems are either directly or indirectly interconnected with the systems of the Sponsoring Companies and who of necessity together with the parties hereto must unify their efforts cooperatively to achieve effective and efficient interconnected systems operation) in developing and executing operating procedures that will enable the parties hereto to avoid to the extent practicable deviations from scheduled deliveries.

In order to foster coordination of the operation and maintenance of Corporation's transmission facilities with those facilities of Sponsoring Companies that are owned or functionally controlled by a regional transmission organization or independent system operator, Corporation shall use commercially reasonable efforts to enter into a coordination agreement with any regional transmission organization or independent system operator approved by the Federal Energy Regulatory Commission that operates transmission facilities that interconnect with Corporation's transmission facilities, and to enter into a mutually agreeable services agreement with a regional transmission organization or independent system operator to provide the Corporation with reliability and security coordination services and other related services.

9.04. *Power Deliveries as Affected by Physical Characteristics of Systems.* It is recognized that the physical and electrical characteristics of the transmission facilities of the interconnected network of which the transmission systems of the Sponsoring Companies, Corporation, and other systems of third parties not parties hereto are a part, may at times preclude the direct delivery at the points of interconnection between the transmission systems of one or more of the Sponsoring Companies and Corporation, of some portion of the energy supplied under this Agreement, and that in each such case, because of said characteristics, some of the energy will be delivered at points which interconnect the system of one or more of the Sponsoring Companies with systems of companies not parties to this Agreement. The parties hereto shall cooperate in the development of mutually satisfactory arrangements among themselves and with such companies not parties hereto whereby the supply of power and energy contemplated hereunder can be fulfilled.

9.05. *Operating Committee.* There shall be an "Operating Committee" consisting of one member appointed by the Corporation and one member appointed by each of the Sponsoring Companies electing so to do; provided that, if any two or more Sponsoring Companies are Affiliates, then such Affiliates shall together be entitled to appoint only one member to the Operating Committee. 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, (ii) procedures for power and energy accounting, (iii) procedures for the reservation and scheduling of firm and non-firm transmission service under the Tariff for the delivery of Available Power and Available Energy, (iv) the Minimum Generating Unit Output, and (v) the form of notifications relating to power and energy and the price thereof. In addition, the Operating Committee shall consider and make recommendations to Corporation's Board of Directors with respect to such other problems as may arise affecting the transactions under this Agreement. The decisions of the Operating Committee, including the adoption or modification of any procedure by the Operating Committee pursuant to this Section 9.04, must receive the affirmative vote of at least two-thirds of the members of the Operating Committee, regardless of the number of members of the Operating Committee present at any meeting.

9.06. *Acknowledgment of Certain Rights.* For the avoidance of doubt, all of the parties to this Agreement acknowledge and agree that (i) as of the effective date of the Current Agreement, certain rights and obligations of the Sponsoring Companies or their predecessors under the Original Agreement were changed, modified or otherwise removed, (ii) to the extent that the rights of any Sponsoring Company or their predecessors were thereby changed, modified or otherwise removed as of the effective date of the Current Agreement, such Sponsoring Company may be entitled to rights under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the Federal Energy Regulatory Commission ("FERC"), (iii) as a result of the elimination as of the effective date of the Current Agreement of the firm transmission service previously provided during the term of the Original Agreement to Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems by certain Sponsoring Companies or their predecessors whose transmission systems were directly connected to the Corporation's facilities, such Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems shall have been entitled to such "roll over" firm transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement, to the border of such Sponsoring Company system and intervening Sponsoring Company system, as would be accorded a long-term firm point-to-point transmission service reservation under the then otherwise applicable FERC Open Access Transmission Tariff ("OATT"), (iv) the obligation of any Sponsoring Company to maintain or expand transmission capacity to accommodate another Sponsoring Company's "roll over" rights to transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement shall be consistent with the obligations it would have for long-term firm point-to-point transmission service provided pursuant to the then otherwise applicable OATT, and (v) the parties shall cooperate with any Sponsoring Company that seeks to obtain and/or exercise any such rights available under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the FERC.

9.07. *Term of Agreement.* This Agreement shall become effective upon the Effective Date and shall terminate upon the earlier of: (1) June 30, 2040 or (2) the sale or other disposition of all of the facilities of the Project Generating Stations or the permanent cessation of operation of such facilities; provided that, the provisions of *Articles* 5, 7 and 8, this Section 9.07 and Sections 9.08, 9.09, 9.10, 9.11, 9.12, 9.14, 9.15, 9.16, 9.17 and 9.18 shall survive the termination of this Agreement, and no termination of this Agreement, for whatever reason, shall release any Sponsoring Company of any obligations or liabilities incurred prior to such termination.

9.08. *Access to Records.* Corporation shall, at all reasonable times, upon the request of any Sponsoring Company, grant to its representatives reasonable access to the books, records and accounts of the Corporation, and furnish such Sponsoring Company such information as it may reasonably request, to enable it to determine the accuracy and reasonableness of payments made for energy supplied under this Agreement.

9.09. *Modification of Agreement.* Absent the agreement of all parties to this Agreement, the standard for changes to provisions of this Agreement related to rates proposed by a party, a non-party or the Federal Energy Regulatory Commission (or a successor agency) acting sua sponte shall be the "public interest" standard of review set forth in *United Gas Pipeline Co. v. Mobile Gas Serv. Corp.,* 350 U.S. 332 (1956) and *Federal Power Comm'n v. Sierra Pacific Power Co.,* 350 U.S. 348 (1956).

9.10. *Arbitration.* Any controversy, dispute or claim arising out of this Agreement or the refusal by any party hereto to perform the whole or any part thereof, shall be determined by arbitration, in the City of Columbus, Franklin County, Ohio, in accordance with the Commercial Arbitration Rules of the American Arbitration Association or any successor organization, except as otherwise set forth in this Section 9.10.

The party demanding arbitration shall serve notice in writing upon all other parties hereto, setting forth in detail the controversy, dispute or claim with respect to which arbitration is demanded, and the parties shall thereupon endeavor to agree upon an arbitration board, which shall consist of three members ("Arbitration Board"). If all the parties hereto fail so to agree within a period of thirty (30) days from the original notice, the party demanding arbitration may, by written notice to all other parties hereto, direct that any members of the Arbitration Board that have not been agreed to by the parties shall be selected by the American Arbitration Association, or any successor organization. No person shall be eligible for appointment to the Arbitration Board who is an officer, employee, shareholder of or otherwise interested in any of the parties hereto or in the matter sought to be arbitrated.

The Arbitration Board shall afford adequate opportunity to all parties hereto to present information with respect to the controversy, dispute or claim submitted to arbitration and may request further information from any party hereto; provided, however, that the parties hereto may, by mutual agreement, specify the rules which are to govern any proceeding before the Arbitration Board and limit the matters to be considered by the Arbitration Board, in which event the Arbitration Board shall be governed by the terms and conditions of such agreement.

The determination or award of the Arbitration Board shall be made upon a determination of a majority of the members thereof. The findings and award of the Arbitration Board shall be final and conclusive with respect to the controversy, dispute or claim submitted for arbitration and shall be binding upon the parties hereto, except as otherwise provided by law. The award of the Arbitration Board shall specify the manner and extent of the division of the costs of the arbitration proceeding among the parties hereto.

9.11. *Liability.* The rights and obligations of all the parties hereto shall be several and not joint or joint and several.

9.12. *Force Majeure.* No party hereto shall be held responsible or liable for any loss or damage on account of non-delivery of energy hereunder at any time caused by an event of Force Majeure. "Force Majeure" shall mean the occurrence or non-occurrence of any act or event that could not reasonably have been expected and avoided by exercise of due diligence and foresight and such act or event is beyond the reasonable control of such party, including to the extent caused by act of God, fire, flood, explosion, strike, civil or military authority, insurrection or riot, act of the elements, or failure of equipment. For the avoidance of doubt, "Force Majeure" shall in no event be based on any Sponsoring Company's financial or economic conditions, including without limitation (i) the loss of the Sponsoring Company's markets; or (ii) the Sponsoring Company's inability economically to use or resell the Available Power or Available Energy purchased hereunder.

9.13. *Governing Law.* This Agreement shall be governed by, and construed in accordance with, the laws of the State of Ohio.

9.14. *Regulatory Approvals.* This Agreement is made subject to the jurisdiction of any governmental authority or authorities having jurisdiction in the premises and the performance thereof shall be subject to the following:

(a) The receipt of all regulatory approvals, in form and substance satisfactory to Corporation, necessary to permit Corporation to perform all the duties and obligations to be performed by Corporation hereunder.

(b) The receipt of all regulatory approvals, in form and substance satisfactory to the Sponsoring Companies, necessary to permit the Sponsoring Companies to carry out all transactions contemplated herein.

9.15. *Notices.* All notices, requests or other communications under this Agreement shall be in writing and shall be sufficient in all respects: (i) if delivered in person or by courier, upon receipt by the intended recipient or an employee that routinely accepts packages or letters from couriers or other persons for delivery to personnel at the address identified above (as confirmed by, if delivered by courier, the records of such courier), (ii) if sent by facsimile transmission, when the sender receives confirmation from the sending facsimile machine that such facsimile transmission was transmitted to the facsimile number of the addressee, or (iii) if mailed, upon the date of delivery as shown by the return receipt therefor.

9.16. *Waiver.* Performance by any party to this Agreement of any responsibility or obligation to be performed by such party or compliance by such party with any condition contained in this Agreement may by a written instrument signed by all other parties to this Agreement be waived in any one or more instances, but the failure of any party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.

9.17. *Titles of Articles and Sections.* The titles of the Articles and Sections in this Agreement have been inserted as a matter of convenience of reference and are not a part of this Agreement.

9.18. *Successors and Assigns.* This Agreement may be executed in any number of counterparts, all of which shall constitute but one and the same document.

9.181 This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective successors and assigns, but a party to this Agreement may not assign this Agreement or any of its rights, title or interests in or obligations (including without limitation the assumption of debt obligations) under this Agreement, except to a successor to all or substantially all the properties and assets of such party or as provided in Section 9.182 or 9.183, without the written consent of all the other parties hereto.

9.182 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, upon thirty (30) days notice to the Corporation and each other Sponsoring Company, without any further action by the Corporation or the other Sponsoring Companies, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Permitted Assignee, provided that, the assignee and assignor of the rights, title and interests in, and obligations under, this Agreement have executed an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion (including, without limitation; the agreement by the Sponsoring Company assigning such rights, title and interests in, and obligations under, this Agreement to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's then-existing securities or agreements resulting from such assignment).

9.183 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, subject to compliance with all of the requirements of this Section 9.183, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party without any further action by the Corporation or the other Sponsoring Companies.

(a) A Sponsoring Company (the "Transferring Sponsor") that desires to assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party shall deliver an Offer Notice to the Corporation and each other Sponsoring Company. The Offer Notice shall be deemed to be an irrevocable offer of the subject rights, title and interests in, and obligations under this Agreement to each of the other Sponsoring Companies that is not an Affiliate of the Transferring Sponsor, which offer must be held open for no less than thirty (30) days from the date of the Offer Notice (the "Election Period").

(b) The Sponsoring Companies (other than the Transferring Sponsor and its Affiliates) shall first have the right, but not the obligation, to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice at the price and on the terms specified therein by delivering written notice of such election to the Transferring Sponsor and the Corporation within the Election Period; provided that, irrespective of the terms and conditions of the Offer Notice, a Sponsoring Company may condition its election to purchase the interest described in the Offer Notice on the receipt of approval or consent from such Sponsoring Company's Board of Directors; provided further that, written notice of such conditional election must be delivered to the Transferring Sponsor and the Corporation within the Election Period and such conditional election shall be deemed withdrawn (as if it had never been provided) unless the Sponsoring Company that delivered such conditional election subsequently delivers written notice to the Transferring Sponsor and the Corporation on or before the tenth (10^{th}) day after the expiration of the Election Period that all necessary approval or consent of such Sponsoring Company's Board of Directors have been obtained. To the extent that more than one Sponsoring Company exercises its right to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice in accordance with the previous sentence, such rights, title and interests in, and obligations under this Agreement shall be allotted (successively if necessary) among the Sponsoring Companies exercising such right in proportion to their respective Power Participation Ratios.

(c) Each Sponsoring Company exercising its right to purchase any rights, title and interests in, and obligations under this Agreement pursuant to this Section 9.183 may choose to have an Affiliate purchase such rights, title and interests in, and obligations under this Agreement; provided that, notwithstanding anything in this Section 9.183 to the contrary, any assignment to a Sponsoring Company or its Affiliate hereunder must comply with the requirements of Section 9.182.

(d) If one or more Sponsoring Companies have elected to purchase all of the rights, title and interests in, and obligations under this Agreement of the Transferring Sponsor pursuant to the Offer Notice, the assignment of such rights, title and interests in, and obligations under this Agreement shall be consummated as soon as practical after the delivery of the election notices, but in any event no later than fifteen (15) days after the filing and receipt, as applicable, of all necessary governmental filings, consents or other approvals and the expiration of all applicable waiting periods. At the closing of the purchase of such rights, title and interests in, and obligations under this Agreement from the Transferring Sponsor, the Transferring Sponsor shall provide representations and warranties customary for transactions of this type, including those as to its title to such securities and that there are no liens or other encumbrances on such securities (other than pursuant to this Agreement) and shall sign such documents as may reasonably be requested by the Corporation and the other Sponsoring Companies. The Sponsoring Companies or their Affiliates shall only be required to pay cash for the rights, title and interests in, and obligations under this Agreement being assigned by the Transferring Sponsor.

(e) To the extent that the Sponsoring Companies have not elected to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice, the Transferring Sponsor may, within one-hundred and eighty (180) days after the later of the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable), enter into a definitive agreement to, assign such rights, title and interests in, and obligations under this Agreement to a Third Party at a price no less than 92.5% of the purchase price specified in the Offer Notice and on other material terms and conditions no more favorable to the such Third Party than those specified in the Offer Notice; provided that such purchases shall be conditioned upon: (i) such Third Party having long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, with a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if such Third Party's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such Third Party's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); (ii) the filing or receipt, as applicable, of any necessary governmental filings, consents or other approvals; (iii) the determination by counsel for the Corporation that the assignment of the rights, title or interests in, or obligations under, this Agreement to such Third Party would not cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer; and (iv) such Third Party executing a counterpart of this Agreement, and both such Third Party and the Sponsoring Company which is assigning its rights, title and interests in, and obligations under, this Agreement executing such other documents as may be reasonably requested by the Corporation (including, without limitation, an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion and containing the agreement by such Sponsoring Company to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's then-existing securities or agreements resulting from such assignment). In the event that the Sponsoring Company and a Third Party have not entered into a definitive agreement to assign the interests specified in the Offer Notice to such Third Party within the later of one-hundred and eighty (180) days after the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable) for any reason or if either the price to be paid by such Third Party would be less than 92.5% of the purchase price specified in the Offer Notice or the other material terms of such assignment would be more favorable to such Third Party than the terms specified in the Offer Notice, then the restrictions provided for herein shall again be effective, and no assignment of any rights, title and interests in, and obligations under this Agreement may be made thereafter without again offering the same to Sponsoring Companies in accordance with this Section 9.183.

ARTICLE 10

REPRESENTATIONS AND WARRANTIES

10.01. *Representations and Warranties*. Each Sponsoring Company hereby represents and warrants for itself, on and as of the date of this Agreement, as follows:

(a) it is duly organized, validly existing and in good standing under the laws of its state of organization, with full corporate power, authority and legal right to execute and deliver this Agreement and to perform its obligations hereunder;

(b) it has duly authorized, executed and delivered this Agreement, and upon the execution and delivery by all of the parties hereto, this Agreement will be in full force and effect, and will constitute a legal, valid and binding obligation of such Sponsoring Company, enforceable in accordance with the terms hereof, except as enforceability may be limited by applicable bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally;

(c) Except as set forth in Schedule 10.01(c) hereto, no consents or approvals of, or filings or registrations with, any governmental authority or public regulatory authority or agency, federal state or local, or any other entity or person are required in connection with the execution, delivery and performance by it of this Agreement, except for those which have been duly obtained or made and are in full force and effect, have not been revoked, and are not the subject of a pending appeal; and

(d) the execution, delivery and performance by it of this Agreement will not conflict with or result in any breach of any of the terms, conditions or provisions of, or constitute a default under its charter or by-laws or any indenture or other material agreement or instrument to which it is a party or by which it may be bound or result in the imposition of any liens, claims or encumbrances on any of its property.

ARTICLE 11

EVENTS OF DEFAULT AND REMEDIES

11.01. *Payment Default*. If any Sponsoring Company fails to make full payment to Corporation under this Agreement when due and such failure is not remedied within ten (10) days after receipt of notice of such failure from the Corporation, then such failure shall constitute a "Payment Default" on the part of such Sponsoring Company. Upon a Payment Default, the

Corporation may suspend service to the Sponsoring Company that has caused such Payment Default for all or part of the period of continuing default (and such Sponsoring Company shall be deemed to have notified the Corporation and the other Sponsoring Companies that any Available Energy shall be available for scheduling by such other Sponsoring Companies in accordance with Section 4.032). The Corporation's right to suspend service shall not be exclusive, but shall be in addition to all remedies available to the Corporation at law or in equity. No suspension of service or termination of this Agreement shall relieve any Sponsoring Company of its obligations under this Agreement, which are absolute and unconditional.

11.02. *Performance Default.* If the Corporation or any Sponsoring Company fails to comply in any material respect with any of the material terms, conditions and covenants of this Agreement (and such failure does not constitute a Payment Default under Section 11.01), the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall give the defaulting party written notice of the default ("Performance Default"). To the extent that a Performance Default is not cured within thirty (30) days after receipt of notice thereof (or within such longer period of time, not to exceed sixty (60) additional days, as necessary for the defaulting party with the exercise of reasonable diligence to cure such default), then the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall have all of the rights and remedies provided at law and in equity, other than termination of this Agreement or any release of the obligation of the Sponsoring Companies to make payments pursuant to this Agreement, which obligation shall remain absolute and unconditional.

11.03. *Waiver.* No waiver by the Corporation or any Sponsoring Company of any one or more defaults in the performance of any provision of this Agreement shall be construed as a waiver of any other default or defaults, whether of a like kind or different nature.

11.04. *Limitation of Liability and Damages.* TO THE FULLEST EXTENT PERMITTED BY LAW, NEITHER THE CORPORATION, NOR ANY SPONSORING COMPANY SHALL BE LIABLE UNDER THIS AGREEMENT FOR ANY CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST REVENUES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, OR OTHERWISE.

[*Signature pages follow*]

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

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Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

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Its ____________________

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By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

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Its ____________________

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Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By [signature]
Its Vice President

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

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Its ______________________

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By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By [signature]
Its Vice President

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

030860-0015-02023-Active.12026116.4

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its Vice President

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

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OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By Anthony J. Ahern
Its President & CEO

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

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OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By Gary Stephenson
Its EXECUTIVE VICE PRESIDENT
Gary Stephenson

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

030860-0015-02023-Active 12026116.4

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Its ____________________

APPALACHIAN POWER COMPANY

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BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By Gary R Leidich
Its President

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

030860-0015-02023-Active.12026116.4

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By [signature]
Its Sr Vice President

030860-0015-02023-Active 12026116.4

LOUISVILLE GAS AND ELECTRIC COMPANY

By [signature]
Its VP Trans. & Generation Services

MONONGAHELA POWER COMPANY

By ____________________
Its ____________________

OHIO POWER COMPANY

By ____________________
Its ____________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

MONONGAHELA POWER COMPANY

By ____________________
Its ____________________

OHIO POWER COMPANY

By ____________________
Its ____________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ______________________
Its ______________________

MONONGAHELA POWER COMPANY

By ______________________
Its General Manager, Electric Supply

OHIO POWER COMPANY

By ______________________
Its ______________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ______________________
Its ______________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ______________________
Its ______________________

MONONGAHELA POWER COMPANY

By ______________________
Its ______________________

OHIO POWER COMPANY

By ______________________
Its ______________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By Ronald E. Christian
Its President

PENINSULA GENERATION COOPERATIVE

By Daniel H. DeCoeur
Its President

APPROVED AS TO FORM:

BRIAN E. VALICE
ATTORNEY FOR PENINSULA
GENERATION COOPERATIVE

SCHEDULE 10.01(c)

Allegheny Energy Supply Company, L.L.C.

and

Monongahela Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Appalachian Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Approval of the Virginia State Corporation Commission

Filing with the Public Service Commission of West Virginia

SCHEDULE 10.01(c)

Buckeye Power Generating, LLC

None

SCHEDULE 10.01(c)

Columbus Southern Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

The Dayton Power and Light Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Duke Energy Ohio, Inc.

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

FirstEnergy Generation Corp.

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Indiana Michigan Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Filing with the Indiana Utility Regulatory Commission

SCHEDULE 10.01(c)

Kentucky Utilities Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Consent or approval of, or filings or registrations with, the Kentucky Public Service Commission may be required

SCHEDULE 10.01(c)

Louisville Gas and Electric Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Consent or approval of, or filings or registrations with, the Kentucky Public Service Commission may be required

SCHEDULE 10.01(c)

Ohio Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Peninsula Generation Cooperative

None

SCHEDULE 10.01(c)

Southern Indiana Gas and Electric Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

PAUL CHODAK III

Executive Vice President – Generation

Paul Chodak is executive vice president – Generation. He is responsible for the management of AEP's nuclear, fossil, hydro and wind generating units, and Ohio Valley Electric Corp./Indiana-Kentucky Electric Corporation's (OVEC/IKEC) generating assets. This includes engineering, construction and operation of generating units, and activities related to fuel procurement and emission monitoring and logistics. The Cook Nuclear, Engineering, the Projects & Field Services, Fossil & Hydro Generation, Environmental Services, regulated Commercial Operations and regulated Generation Development groups report to him.

Previously, Chodak was executive vice president- Utilities, overseeing the activities of all AEP's utility operating companies. In this role, he was responsible for the growth of AEP's regulated utility operations as they focused on and invested in advanced technologies to deliver more reliable, affordable and cleaner energy to customers.

From 2008-2016, Chodak successfully led AEP's Southwestern Electric Power and then Indiana and Michigan Power companies as their president and chief operating officer. In both positions, he was responsible for company operations and financial performance, as well as a wide range of external relationships.

Chodak began his career with AEP in 2001 as a senior project manager. In 2002, he was named director of regional engineering for regulated generation, working with a team that provided engineering support for power plants. He was named managing director, corporate technology development in 2003, and led a team that evaluated existing pollution control technologies and recommended solutions to meet environmental compliance requirements.

In 2004, Chodak led efforts to implement AEP's environmental compliance plan as director, environmental programs and was responsible for more than $2 billion of capital investments. He was part of the team responsible for the successful completion of the Mountaineer Plant flue gas desulfurization retrofit project.

In early 2007, Chodak was named director, new generation, responsible for the installation of several natural gas fueled power plants, both simple- and combined-cycle plants, as well as AEP's integrated gasification combined cycle (IGCC) program. He was part of the team that successfully commissioned the first two units at AEP's Harry D. Mattison Power Plant in northwest Arkansas, as well as the Stall Plant in Shreveport, La.

Prior to joining AEP, Chodak was a staff scientist at Los Alamos National Laboratory conducting research on technology and policy issues concerning nuclear power and proliferation risks. Chodak served more than seven years in the U.S. Navy as a submarine officer, earning numerous commendations and completing both submarine and chief engineer officer qualifications.

He earned a doctorate degree in nuclear engineering from Massachusetts Institute of Technology in 1996 and completed MIT's Reactor Technology Course for Utilities Executives in 2011. He holds a master's degree in civil engineering from Virginia Polytechnic Institute and State University, and a bachelor of science degree in chemical engineering with honors from Worcester Polytechnic Institute. Chodak graduated from the Harvard Business School Advanced Management Program in 2015.

Chodak serves on the Board for the Columbus Regional Airport Authority and is a Capital University Trustee. He is also a Habitat for Humanity Champion. At AEP, he is an executive sponsor of the Military Veteran Employee Resource Group (MVERG).

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

KENTUCKY UTILITIES COMPANY

Response to Sierra Club's Initial Data Requests
Dated November 19, 2018

Case No. 2018-00294

Question No. 13

Responding Witness: David S. Sinclair

Q-13. Produce the minutes from each meeting of the OVEC Board of Directors since January 1, 2015.

A-13. See attached. Proposed final OVEC board minutes as routinely provided to and in the Company's possession are provided. Certain actions of OVEC's board are taken via unanimous written consent, but the Company does not routinely receive or possess completed final versions of such consents. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

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 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 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 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:

CONFIDENTIAL INFORMATION REDACTED

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			
Union Retiree Medical VEBA Trust			
Retiree Medical VEBA Trust			
Retiree Life Insurance VEBA Trust			
401(h) - Retiree Medical			
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

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

CONFIDENTIAL INFORMATION REDACTED

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]

[redacted] [redacted]. On a motion duly made, seconded, Sinclair 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] [redacted] [redacted] [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] [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 [redacted] clair 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:

CONFIDENTIAL INFORMATION REDACTED

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	160,320,632	-	160,320,632
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

CONFIDENTIAL INFORMATION REDACTED

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]

[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

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]

[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 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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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]

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

CONFIDENTIAL INFORMATION REDACTED

OHIO VALLEY ELECTRIC CORPORATION
Minutes of Special Meeting of the
Board of Directors' Meeting via Teleconference
February 21, 2018

A Special Meeting of the Board of Directors of **OHIO VALLEY ELECTRIC CORPORATION** (OVEC) via teleconference was called to order by the President on Wednesday, February 21, 2018, at 9:00 a.m., pursuant to notice duly given.

Nicholas K. Akins, President of the Corporation, acted as Chairman of the meeting, and Justin J. Cooper, Chief Financial Officer, Secretary and Treasurer of the Corporation, acted as Secretary of the meeting.

Mr. Cooper reported that the following Directors were present for the meeting:

Nicholas K. Akins	Mark C. McCullough
Thomas Alban	Mark E. Miller
Eric D. Baker	Steven K. Nelson
Lonnie E. Bellar	Patrick W. O'Loughlin
Wayne D. Games	David W. Pinter
James R. Haney	Paul W. Thompson
Lana L. Hillebrand	John A. Verderame

At the request of Mr. Akins, Mr. Brian Chisling, with Simpson Thacher & Bartlett LLP, reviewed the Cost/Benefit Analysis of OVEC integrating into PJM. Mr. Chisling stated that, as specified in such analysis, there would be [redacted]. On a motion duly made, seconded, and unanimously adopted, it was

RESOLVED, that in accordance with the order of the Federal Energy Regulatory Commission (FERC) approving OVEC's application for membership in PJM Interconnection, L.L.C. (PJM), previously provided to the Board (the "FERC PJM Order"), OVEC is hereby authorized and approved to execute and deliver all of the agreements and other documents described therein and otherwise in accordance with the rules and regulations of PJM (together, the "Integration Agreements") in order for OVEC to become a full member of, and fully integrate the OVEC and IKEC generating facilities and transmission system into, PJM; and it is further

RESOLVED, that, in furtherance of the foregoing, any Officer of OVEC (each an "Authorized Officer") is hereby authorized, approved and directed in the name of and on behalf of OVEC, to execute and deliver such Integration Agreements with such changes, deletions and additions thereto as deemed appropriate or proper by any such Authorized Officer, the execution and delivery of such Integration Agreements being conclusive evidence of such determination; and it is further

RESOLVED, that each Officer of OVEC is authorized and directed to prepare, execute and file, or cause to be prepared, executed and filed, all agreements, certificates, statements, reports, documents, instruments and papers required to be filed by OVEC in accordance with the Integration Agreements, the FERC PJM Order and the PJM tariff and in order for OVEC to comply with all applicable requirements and rules and regulations of PJM, FERC and applicable law and any other administrative or governmental agency (domestic or foreign) in connection with the Integration Agreements, the FERC PJM Order or any other matter relating to PJM integration and to prepare, sign, seal, execute, file, record and deliver such other agreements, certificates, statements, termination and other notices, reports, documents, instruments and papers, from time to time necessary, desirable or appropriate, as may be executed by any such Officer pursuant to the Integration Agreements, the FERC PJM Order, the PJM tariff and these resolutions and the transactions contemplated thereby and hereby, and to do any and all other acts and things, in each case to effectuate the purpose and intent of these resolutions.

There being no further business to come before the Board, the meeting was adjourned.

Secretary
OHIO VALLEY ELECTRIC CORPORATION

OHIO VALLEY ELECTRIC CORPORATION
Minutes of Special Meeting of the
Board of Directors' Meeting via Teleconference
April 27, 2018

A Special Meeting of the Board of Directors of **OHIO VALLEY ELECTRIC CORPORATION** (OVEC) via teleconference was called to order by Mark C. McCullough on Friday, April 27, 2018, at 8:30 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 April 27, 2018 in the absence of the President of this Corporation.

Mr. McCullough acted as Chairman of the meeting, and Justin J. Cooper, Chief Financial Officer, Secretary and Treasurer of the Corporation, acted as Secretary of the meeting.

Mr. Cooper reported that the following Directors were present for the meeting:

Thomas Alban	Mark C. McCullough
Eric D. Baker	Mark E. Miller
Lonnie E. Bellar	Steven K. Nelson
Wayne D. Games	Patrick W. O'Loughlin
James R. Haney	Julie Sloat
Lana L. Hillebrand	Paul W. Thompson

John A. Verderame

WHEREAS, effective as of the election of the persons specified herein, Mr. Nicholas K. Akins will be resigning as a member of the Board of Directors (Board) of each of OVEC and IKEC and as a member of the Executive Committee and as president of OVEC and IKEC;

WHEREAS, effective as of the election of the persons specified herein, Mr. Mark C. McCullough will be resigning as a member and Chairman of the Human Resources Committee of OVEC; and

WHEREAS, OVEC and IKEC management have recommended to the remaining members of their respective Boards those persons named below to be elected and/or appointed as Directors to the Boards, as officers and/or as members of Committees of OVEC and IKEC as described below.

NOW, THEREFORE, BE IT:

RESOLVED, that, subject to any necessary action by the Federal Energy Regulatory Commission (FERC) under Section 305 of the Federal Power Act, Mr. Mark C. McCullough be elected as the president of OVEC; and it is further

RESOLVED, that, subject to any necessary action by FERC, under Section 305 of the Federal Power Act, Mr. Chris T. Beam be elected a Director of the Board of OVEC and appointed as a member of the Human Resources Committee of OVEC; and it is further

RESOLVED, that, subject to any necessary action by FERC under Section 305 of the Federal Power Act, Ms. Julie Sloat be appointed as a member of the Executive Committee of OVEC; and it is further

RESOLVED, that subject to any necessary action by FERC under Section 305 of the Federal Power Act, Ms. Lana L. Hillebrand be appointed as Chairwoman of the Human Resources Committee of OVEC.

At the request of Mr. McCullough, Mr. Brian Chisling, with Simpson Thacher & Bartlett LLP, [redacted].

There being no further business to come before the Board, the meeting was adjourned.

Secretary
OHIO VALLEY ELECTRIC CORPORATION

CONFIDENTIAL INFORMATION REDACTED

OHIO VALLEY ELECTRIC CORPORATION
Minutes of Special Meeting of the
Board of Directors' Meeting via Teleconference
June 15, 2018

A Special Meeting of the Board of Directors of **OHIO VALLEY ELECTRIC CORPORATION** (OVEC) via teleconference was called to order by the President on Friday, June 15, 2018, at 3:00 p.m., pursuant to notice duly given.

Mark C. McCullough, President of the Corporation, acted as Chairman of the meeting, and Justin J. Cooper, Chief Financial Officer, Secretary and Treasurer of the Corporation, acted as Secretary of the meeting.

Mr. Cooper reported that the following Directors were present for the meeting:

Thomas Alban	Mark E. Miller
Eric D. Baker	Patrick W. O'Loughlin
Lonnie E. Bellar	Julie Sloat
Mark C. McCullough	John A. Verderame

At the request of Mr. McCullough, Mr. Brian Chisling, with Simpson Thacher & Bartlett LLP, [redacted].

There being no further business to come before the Board, the meeting was adjourned.

Secretary
OHIO VALLEY ELECTRIC CORPORATION

CONFIDENTIAL INFORMATION REDACTED

OHIO VALLEY ELECTRIC CORPORATION
Minutes of Special Meeting of the
Board of Directors' Meeting via Teleconference
June 28, 2018

A Special Meeting of the Board of Directors of **OHIO VALLEY ELECTRIC CORPORATION** (OVEC) via teleconference was called to order by the President on Thursday, June 28, 2018, at 3:00 p.m., pursuant to notice duly given.

Mark C. McCullough, President of the Corporation, acted as Chairman of the meeting, and Justin J. Cooper, Chief Financial Officer, Secretary and Treasurer of the Corporation, acted as Secretary of the meeting.

Mr. Cooper reported that the following Directors were present for the meeting:

Thomas Alban	Mark C. McCullough
Eric D. Baker	Mark E. Miller
Christian T. Beam	Steven K. Nelson
Lonnie E. Bellar	Patrick W. O'Loughlin
James R. Haney	Julie Sloat
Lana L. Hillebrand	John A. Verderame
Wayne D. Games	

At the request of Mr. McCullough, Mr. Brian Chisling, with Simpson Thacher & Bartlett LLP, [redacted]. After discussion on these topics and related matters by the Board, a motion duly made, seconded, and adopted, it was:

> **RESOLVED,** that OVEC's integration into PJM as a full member should proceed, with a target integration date of December 1, 2018; and that certain PJM administrative charges not otherwise payable absent such integration are to be properly allocated to those Sponsoring Companies under the Inter-Company Power Agreement that participate in the PJM market.

There being no further business to come before the Board, the meeting was adjourned.

Secretary
OHIO VALLEY ELECTRIC CORPORATION

Q1

State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

5.14.2020

2020

Recommendations

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[1] The MMU initiates and proposes changes to the design of the markets and the PJM Market Rules in stakeholder and regulatory proceedings.[2] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM management, and the PJM Board; participates in PJM stakeholder meetings and working groups regarding market design matters; publishes proposals, reports and studies on market design issues; and makes filings with the Commission on market design issues.[3] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[4] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[5]

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects or that it could be easily resolved.

1 OATT Attachment M § IV.D.
2 *Id.*
3 *Id.*
4 *Id.*
5 OATT Attachment M § VI.A.

The MMU is also tracking PJM's progress in addressing these recommendations. The MMU recognizes that part of the process of addressing recommendations may include discussions in the stakeholder process, FERC decisions and court decisions and those elements are included in the tracking. The MMU recognizes that PJM does not have the unilateral authority to implement changes to the tariff but PJM has a significant role in the issues PJM focuses on, in proposed changes to the PJM manuals, and in the recommendations PJM makes to the stakeholders and to FERC. Each recommendation includes a status. The status categories are:

- **Adopted:** PJM has implemented the recommendation made by the MMU.
- **Partially adopted:** PJM has implemented part of the recommendation made by the MMU.
- **Not adopted:** PJM does not plan to implement the recommendation made by the MMU, or has not yet implemented any part of the recommendation made by the MMU. Where the subject of the recommendation is pending stakeholder, FERC, or court action, that status is noted.

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes," the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.[6]

In this *2020 Quarterly State of the Market Report for PJM: January through March*, the MMU includes four new recommendations.

6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

Exhibit - SC-45

Actual Costs from Reconciliations

	U-17679-R	U-17919-R	U-20070	U-20204	U-20224
	2015	**2016**	**2017**	**2018**	**2019**
	MWH	MWH	MWH	MWH	MWH
GENERATION:					
Fossil Generation	7,282,551	5,778,942	5,461,727	5,947,057	4,073,474
Affiliated Transportation Exclusion	0	0	0	0	0
Nuclear Generation	16,519,114	15,359,858	17,592,001	17,610,814	16,157,848
Post 4/6/83 Spent Nuclear Fuel	0	0	0	0	0
Hydro Generation	95,427	108,726	107,362	115,150	114,667
Solar Generation	0	7,855	24,219	20,748	19,467
Emission Allowances	0	0	0	0	0
Consumables	0	0	0	0	0
TOTAL GENERATION	23,897,092	21,255,381	23,185,309	23,693,769	20,365,456
Plus:					
AEG Purchases/Assoc	4,356,078	4,045,257	3,823,206	4,162,940	2,851,429
OVEC	647,662	743,027	937,620	959,123	926,291
Other System Purchases/PJM Ancillaries	1,441,897	2,205,938	1,586,582	1,249,563	2,069,485
Wind Purchases	1,365,642	1,363,275	1,403,241	1,287,850	1,298,945
Cogeneration	2,152	1,743	1,134	1,192	783
FTR Rev Net Congestion Costs-LSE	0	0	0	0	0
Transmission Losses	0	0	0	0	0
Subtotal	7,813,431	8,359,240	7,751,783	7,660,668	7,146,933
Less:					
Off-System Sales Margin	(17,159)	(23,619)	1,670	(2,540)	(137)
Special Service Customers	(8,926)	(22,170)	(36,951)	(1,942)	(1,456)
Non-Firm Sales/Off-System Sales Rev-COGS	(7,410,468)	(4,898,203)	(6,912,995)	(7,004,765)	(4,301,137)
Subtotal	(7,436,553)	(4,943,992)	(6,948,276)	(7,009,247)	(4,302,730)
Net Energy Requirement (NER)	24,273,970	24,670,629	23,988,816	24,345,190	23,209,659
NER with 4.6% Loss Factor					

	U-17679-R	U-17919-R	U-20070	U-20204	U-20224
	2015	**2016**	**2017**	**2018**	**2019**
	$	$	$	$	$
GENERATION:					
Fossil Generation	181,143,312	145,214,582	129,832,644	141,335,054	107,808,079
Affiliated Transportation Exclusion	(20,485,829)	(23,302,058)	(12,192,639)	(14,714,348)	(12,787,791)
Nuclear Generation	147,005,602	131,186,766	132,854,012	118,713,830	93,313,723
Post 4/6/83 Spent Nuclear Fuel	0	0	0	0	0
Hydro Generation	0	0	0	0	0
Solar Generation	0	545,137	1,756,363	1,557,554	1,507,526
Emission Allowances	3,162,685	1,383,635	1,727,507	1,513,167	693,398
Consumables	11,664,524	16,021,646	16,405,595	14,098,059	9,936,858
TOTAL GENERATION	322,490,294	271,049,708	270,383,482	262,503,316	200,471,793
Plus:					
AEG Purchases/Assoc	232,107,960	228,528,089	223,899,492	237,908,177	214,863,335
OVEC	43,640,447	44,019,652	50,520,494	50,240,295	52,265,549
Other System Purchases/PJM Ancillaries	63,642,507	75,044,123	64,043,573	60,031,781	65,871,742
Wind Purchases	72,114,146	72,364,998	74,475,805	70,483,248	73,067,245
Cogeneration	246,439	193,309	78,179	49,038	23,725
FTR Rev Net Congestion Costs-LSE	10,314,501	15,436,201	10,864,982	17,641,108	8,979,048
Transmission Losses	20,035,178	16,884,169	15,980,538	17,518,201	12,091,657
Subtotal	442,101,178	452,470,541	439,863,063	453,871,848	427,162,301
Less:					
Off-System Sales Margin	(27,826,464)	(4,534,876)	(11,047,147)	(19,930,390)	(21,252,800)
Special Service Customers	(793,854)	(1,540,657)	(2,624,318)	(138,089)	(64,880)
Non-Firm Sales/Off-System Sales Rev-COGS	(208,144,951)	(146,188,227)	(184,779,632)	(182,455,584)	(107,464,026)
Subtotal	(236,765,269)	(152,263,760)	(198,451,097)	(202,524,063)	(128,781,706)
Net Energy Requirement (NER)	527,826,203	571,256,489	511,795,448	513,851,101	498,852,388
NER with 4.6% Loss Factor					

	U-17679-R	U-17919-R	U-20070	U-20204	U-20224
	2015	**2016**	**2017**	**2018**	**2019**
	Mills/kWh	Mills/kWh	Mills/kWh	Mills/kWh	Mills/kWh
GENERATION:					
Fossil Generation	24.87	25.13	23.77	23.77	26.47
Affiliated Transportation Exclusion					
Nuclear Generation	8.90	8.54	7.55	6.74	5.78
Post 4/6/83 Spent Nuclear Fuel					
Hydro Generation	0.00	0.00	0.00	0.00	0.00
Solar Generation	0.00	69.40	72.52	75.07	77.44
Emission Allowances					
Consumables					
TOTAL GENERATION	13.49	12.75	11.66	11.08	9.84
Plus:					
AEG Purchases/Assoc	53.28	56.49	58.56	57.15	75.35
OVEC	67.38	59.24	53.88	52.38	56.42
Other System Purchases/PJM Ancillaries	44.14	34.02	40.37	48.04	31.83
Wind Purchases	52.81	53.08	53.07	54.73	56.25
Cogeneration	114.52	110.91	68.94	41.14	30.30
FTR Rev Net Congestion Costs-LSE					
Transmission Losses					
Subtotal	56.58	54.13	56.74	59.25	59.77
Less:					
Off-System Sales Margin					
Special Service Customers	88.94	69.49	71.02	71.11	44.56
Non-Firm Sales/Off-System Sales Rev-COGS	28.09	29.85	26.73	26.05	24.99
Subtotal	31.84	30.80	28.56	28.89	29.93
Net Energy Requirement (NER)	21.74	23.16	21.33	21.11	21.49
NER with 4.6% Loss Factor					

MOODY'S INVESTORS SERVICE

CREDIT OPINION
13 December 2018

Update

Rate this Research

RATINGS

Ohio Valley Electric Corp

Domicile	Piketon, Ohio, United States
Long Term Rating	Ba1
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Ohio Valley Electric Corp

Update following ratings affirmation with stable outlook

Summary

Ohio Valley Electric Corporation's (OVEC) credit profile reflects the governing provisions of its long-term Inter-Company Power Agreement (ICPA) between thirteen investor-owned and cooperative utility companies (collectively, the sponsors), one of which is currently in default. Our view considers the steps taken by management and the remaining sponsors to mitigate the financial impact of the small (under 5% of revenues) defaulting sponsor as well as the overall credit quality of the sponsor group.

Under the ICPA, the sponsors pay monthly demand and transmission charges designed to cover all non- fuel related costs of owning, operating, and maintaining electric generation and transmission facilities, including debt service, irrespective of plant availability or usage. Fuel related costs are recovered through a volumetric energy charge. We currently view the sponsors' overall average credit profile to be investment grade; however, the sponsor obligations are several – not joint, which in the context of our rating methodology for US Municipal Joint Action Agencies, limits our view of their collective credit quality and caps the score for this factor at two notches above the "weakest link". Since the ICPA currently does not include a requirement for non-defaulting sponsors to "step-up" their payments in the event of a default, the weakest link is the sponsor with the lowest credit quality, First Energy Solutions Corp. (FES, unrated), which contributes under 5% of non-fuel related costs (approximately $17 million per year) and is currently in default.

Despite the limitation on methodology factor scoring noted above, our view of OVEC's overall credit profile considers the financial strength of the majority of its sponsors, which are predominately investment grade utilities, the mitigating actions taken by OVEC and the sponsors in response to the current default, and the small, manageable, size of that default. Actions taken include the ongoing funding of a debt reserve at a rate of $2.4 million per month, and the retention of earnings that could be used to offset future payment shortfalls.

Credit strengths

» Effective management of sponsor default and bankruptcy

» Fixed and variable costs, including debt service, are recovered through a strong ownership contract, albeit with a flaw

» Primarily investment grade sponsors/off-takers

» Diminished regulatory uncertainty for Ohio based utility sponsors

Credit challenges

» Sponsor obligations that are several and not joint

» Bankruptcy and subsequent payment default by one sponsor company representing about 5% of revenues

» Weak credit quality of a second merchant power sponsor company, representing about 3% of revenues, which has divested all its non-OVEC generating assets

» Challenging competitive conditions arising from current low prices for natural gas and power

» Constrained liquidity with bank credit facility due within one year

» Elevated carbon transition risk

Rating outlook

The stable outlook recognizes the credit quality of OVEC's non-defaulting sponsors, and the company's actions to address the limited financial impact of the current, ongoing, 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

» Credit supportive changes to the ICPA, such as an inclusion of a step-up provision

» Longer term, an improvement in the overall credit profile of the sponsor group

» Stronger financial metrics, including a debt service coverage ratio above 1.6x

Factors that could lead to a downgrade

» An inability or unwillingness to continue collecting reserve or excess operating funds sufficient to cover payment shortfalls

» Failure to extend OVEC's revolving credit facility beyond its 2019 termination date by early 2019

» Further declines in the credit quality of any sponsors

» A sponsor payment default that was not able to be covered by existing reserves or through a swift replacement of the defaulting party

Profile

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). By virtue of their ownership, 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. OVEC's fuel, operating, capital and debt service requirements costs are passed-through to the sponsors pursuant to the ICPA. The sponsors participate in the management and financial planning of OVEC through the OVEC Board of Directors, and a long-standing management and services agreement with American Electric Power Company Inc. (AEP: Baa1 stable).

Detailed credit considerations

Effective management of the bankruptcy and subsequent payment default by one sponsor company representing about 5% of revenues

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, and for 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.

Fortunately for OVEC, the shortfall created by the FES default is relatively modest and, as there was ample warning of FES' impending default, management was able to take steps to mitigate its impact. These steps include 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 liquidity provides sufficient near term coverage for the FES shortfall, and we expect the sponsors will continue to work toward implementing a longer term solution, including potential credit enhancing improvements to the ICPA, after there is resolution of the issues surrounding the FES bankruptcy.

While it has not filed for bankruptcy, FirstEnergy Corp.'s (FirstEnergy: Baa3, stable) other merchant subsidiary, Allegheny Energy Supply (AES, not rated) (3% of revenues) recently sold all of its non-OVEC generating assets and repaid all of its debt, leaving the company with very limited independent revenue generating ability. AES is continuing to meet its OVEC obligations, however we estimate its earnings shortfall to be around $5 million per year. AES' share of OVEC's fixed cost is about $10 million per year. As such, if it were also to default, the combined FES and AES shortfalls would still be less than the approximately $30 million per year OVEC is currently collecting as a reserve.

Full cost pass through of costs provided by the ICPA historically offset OVEC's weak financial profile

The ICPA contractually binds the sponsor group to pay a demand charge covering all non-fuel costs incurred by OVEC, including debt service, irrespective of plant availability or whether the sponsors take power from OVEC. Sponsor payments are semi-monthly, which we view positively versus the semi-annual payment of interest, as the timing allows OVEC to build the collection of required debt service before it is due. There is also an energy charge designed to recover all fuel-related costs and is payable based on each sponsor's pro-rata share of electricity volumes.

Prior to June 2016, the sponsors made dispatch decisions independently. If a sponsor decided not to take its allocation of the output, it was offered to the remaining sponsors. If the other sponsors did not choose to take that energy, OVEC did not generate the power. Beginning in 2016, OVEC bids over 90% of its energy into the PJM Interconnection (PJM) market on behalf of all of the sponsors, and its two plants will only generate power to the extent it is economic (dispatched by the system operator). Sponsor companies receive their pro-rata share of energy revenues and pay their pro-rata share of fuel costs.

Following FES' March 2018 bankruptcy filing, and the court's July 2018 acceptance of FES' rejection of the ICPA, FES' share of energy has been taken by the remaining sponsors. The sponsors have accepted their allocations and have been paying their pro-rata share of the related variable production costs, but not fixed costs.

The cost recovery provided by the ICPA helps to offset financial metrics that are weak when viewed in the context of Moody's rating methodology for regulated electric and gas utilities (which applies to the majority of the off-takers). In 2017, cash flow from operations excluding changes in working capital (CFO pre-WC) to debt was about 7.5%, marginally stronger than the 5.0% and 4.1% demonstrated in 2016 and 2015. Within the context of our rating methodology for regulated electric and gas utilities, these metrics are typically reflective of a speculative grade credit profile.

On the other hand, the sponsor take-or-pay type obligations that are created under the ICPA result in a structure that, within our rated universe, is more akin to that of a municipal joint action agency, (albeit with primarily non-municipal participants). As a result, we evaluate OVEC under the US municipal joint action agencies rating methodology (JAA Methodology). It is fairly common for joint action agencies to look to recover their costs with little or no margin. Within the context of the JAA Methodology for take-or-pay projects, a fixed obligation charge coverage ratio in the range of 1.0x-1.6x receives a score of "Baa". For 2017, we calculate OVEC's fixed obligation coverage ratio as 1.23x, and its three year historical average is 1.21x. Going forward, even with the shortfall created by the FES bankruptcy, we expect that OVEC will produce a fixed obligation coverage ratio above 1.0x, incorporating the ongoing debt reserve funding, the metric should remain around 1.2x.

Primarily investment grade credit quality of owner/off-takers

With the exception of FES and AES, we view the remainder of OVEC's sponsors (approximately 92%) as having strong investment grade characteristics. However, as the obligations are several and not joint, within the context of our JAA Methodology scorecard grid, the score for this factor is capped at two notches above the weakest link. Since there currently is no "step-up" requirement in the OVEC ICPA, the "weakest link" is the lowest rating in the sponsor group (currently FES which is in default), thereby constraining the score for this factor (45% weight) at B3 - the floor for this factor in the scorecard grid.

The OVEC sponsor group includes: American Electric Power Company, Inc. (AEP), the largest shareholder with 43.5% in total, through its subsidiaries Ohio Power Company (OPCo: A2, stable) at 19.9%, Appalachian Power Company (Baa1, stable) at 15.7%, and Indiana Michigan Power Company (A3, stable) at 7.9%. Buckeye Power Generating LLC (Baa1, stable) is the next largest shareholder with about 18.0%, followed by Duke Energy Ohio, Inc. (Duke Ohio: Baa1, stable) with 9.0% and FirstEnergy Corp. (FirstEnergy: Baa3, stable) with 8.4% through its wholesale generating subsidiaries FirstEnergy Solutions Corp. (not rated) at 4.9%, Allegheny Energy Supply (not rated) at 3.0% and regulated utility Monongahela Power (Baa2, stable) at 0.5%. PPL Corporation (Baa2, stable) has an 8.1% stake through Louisville Gas and Electric (A3, stable) at 5.6% and Kentucky Utilities (A3, stable) at 2.5%, with the remainder held by Peninsula Generation Cooperative (not rated) at 6.7%, Dayton Power & Light (DPL, Baa2, positive) at 4.9%, and Southern Indiana Gas & Electric (A2, negative) at 1.5%. Peninsula Generation Cooperative (Peninsula) and its parent company, Wolverine Power Supply (Wolverine), are not rated by Moody's. However, we view Peninsula and Wolverine as having investment grade-like characteristics.

Regulatory uncertainty for Ohio based sponsors has diminished

The state of Ohio's transition to a deregulated market for electricity resulted in some uncertainty regarding the permanency and mechanics by which the Ohio based OVEC participants that were once vertically integrated utilities (OPCo, Duke Ohio and DPL) would recover their OVEC obligations. Importantly, the OVEC obligations of these entities remain with the utilities that are parties to the ICPA, even though the sponsors may no longer own any generating assets. The ICPA does not contain a "regulatory out" provision, so the risk of non-recovery lies with the sponsor participants.

In prior rate proceedings, the Public Utilities Commission of Ohio (PUCO) allowed the establishment of placeholder riders, initially set at zero, for the recovery of costs associated with the Ohio utilities' OVEC obligations. In 2016 and 2017, the PUCO authorized OPCo and DPL's utilization of their specific OVEC riders through 2024 and 2023, respectively. The PUCO'S OPCo decision was recently upheld by the Ohio Supreme Court. Duke Ohio's request is still pending. Legislative efforts to make utility cost recovery of OVEC obligations more permanent are also underway.

OVEC's plants are challenged to be cost competitive in current low priced power markets

The low natural gas price environment and greater customer efficiencies/conservation efforts have kept the market price for on-peak energy at the AEP-Dayton hub of PJM during 2018 around $40 per MWh; off-peak prices have generally been around $30 per MWh. This is considerably less than OVEC's all-in cost of power to its participants, which in 2018 is estimated to be about $55 per MWh (including fixed costs and debt service). OVEC has been undertaking cost reduction efforts and estimates its energy only costs are currently around $25 MWh, which frequently allows the plants to run as base load, as they were designed, which reduces operational costs and brings down their overall cost per MWh. For example, OVEC's 2018 all-in cost of $55 MWh is a significant improvement from the $64-65 MWh experienced in 2013 and 2015, and below the $56 MWh experienced in 2014 when production spiked due to severe winter weather. For 2019, OVEC estimates the all-in cost of power to its sponsor companies will be similar to 2018.

Beginning in June 2016, OVEC became responsible for bidding all of the PJM sponsor's available energy into the market, so the entirety of the plants are dispatched on a consistent basis when it is economic. This dispatch practice has improved the plant's use factor (percentage of power scheduled versus power availability) to approximately 84% in 2018 and 2017 compared to approximately 71% in 2016. Increased usage contributes to a lower all-in per MWh cost of power for the sponsors. We note that as a strictly merchant plant, in today's market, the plant would not be able to generate sufficient cash flow cover its fixed costs and service its $1.4 billion of debt.

Elevated carbon transition risk

OVEC has an elevated carbon transition risk profile because its operations are limited to the generation of electricity from two coal-fired electric generating plants: the Kyger Creek Plant (1,086 MW) in Ohio and the Clifty Creek plant (1,304 MW) in Indiana. This places the company at a higher risk than other joint action agencies or regulated and municipal utilities that may have a more diversified generating base or own transmission and distribution assets.

Liquidity analysis

OVEC's liquidity is constrained as its partially drawn bank credit facility, which includes a material adverse change clause for new borrowings, is current and due in less than one year. For the twelve months ended September 30, 2018, OVEC generated approximately $123 million in cash flow from operations (CFO), invested $14 million in capital expenditures and made no dividend payments, resulting in free cash flow (FCF) of approximately $109 million. Over the next 12 months, with limited capital expenditures and no dividend payments, the company should continue to be free cash flow positive. In addition, as of December 31, 2017, OVEC had approximately 97 days of liquidity (including the liquid portion of long term investments) on hand, an increase compared to the 68 days at the end of 2016. These figures fall within the range of 30 – 100 days indicated for a score of "Baa" on this factor in the JAA methodology.

Additional external liquidity is provided by OVEC's $200 million unsecured bank revolving facility which matures in November 2019, but is currently in the process of being extended. Our rating and stable outlook assume this extension is completed in the early part of 2019. At September 30, 2018, OVEC had $85 million borrowed under this line of credit. The facility has a covenant requiring maintenance of a minimum of $11 million of consolidated net worth (defined as stockholders' equity); as of September 30, 2018, we estimated the level to be about $23 million. Draws under the facility require a representation of no material adverse change, a credit negative as it may preclude borrowing under the facility when it is needed most. As such, we have not included revolver availability in our calculation of days liquidity on hand.

As mentioned earlier, management has taken proactive steps to shore up its available liquidity in order to provide near-term coverage for the FES shortfall. Traditionally, joint action agencies will establish a debt service reserve (typically covering one year of debt service) for the benefit of the lenders. At its December 2016 meeting, the OVEC Board authorized the funding of a $44 million debt service reserve over 18 months beginning January 2017, which was equivalent to approximately one third of a year of debt service. OVEC now plans to continue funding this debt reserve at a rate of about $30 million per year (current balance is about $60 million), at least until there is one year of debt service. To date, there have been no draws from the 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 also include about $70 million received as part of a prior settlement with the Department of Energy, which could be utilized to cover shortfalls.

Over the next twelve months, we expect OVEC's scheduled debt amortization of approximately $50 million to be recovered through the sponsor's demand charge payments. The company's next non-amortizing debt maturity is in October 2019, when $100 million of revenue bonds mature. In addition, OVEC's upcoming maturities include: 1) $25 million of Ohio Air Quality Development Authority

(OAQDA) variable rate revenue bonds (due in 2026) with letter of credit backing expiring in November 2019, and 2) $50 million of Indiana Finance Authority (IFA) variable rate revenue bonds (due in 2040) with a bank agreement expiring in August 2020. OVEC expects to extend the maturities of these upcoming facilities.

Structural considerations

The strength of the OVEC ICPA is a key factor in determining its credit quality. However, as noted above, the sponsor obligations under the ICPA are several, and there is no requirement for a step-up in payments in the event of a shortfall. A step-up provision, which is common for joint action agencies, would typically require the non-defaulting participants to increase their payments by a maximum percentage (typically 15-25%) in the event a participant default. The ICPA limits assignments of the sponsor obligations to entities that have investment grade ratings from both Moody's and Standard & Poor's. However, there is no ongoing requirement that the existing Sponsors maintain investment grade ratings.

Rating methodology and scorecard factors

Moody's evaluates OVEC's financial performance relative to the US Municipal Joint Action Agencies rating methodology and, as depicted below, based on a lowest possible sponsor score of "B3", the scorecard indicated rating for OVEC is Ba3, two notches below OVEC's Ba1 rating. The Ba1 rating recognizes the small, manageable size of the defaulting sponsor and the overall credit quality of the sponsor group. Our view reflects our expectation that the non-defaulting sponsors will continue to support OVEC through reserves or other means until a longer term solution to the FES shortfall is achieved. Notching factors reflect the current lack of a traditional step-up feature.

Exhibit 1

Factor	Subfactor/Description	Score	Metric
1. Participant Credit Quality and Cost Recovery Framework	a) Participant credit quality. Cost recovery structure and governance	B3	
2. Asset Quality	a) Asset diversity, complexity and history	Baa	
3. Competitiveness	a) Cost competitiveness relative to market	Ba	
4. Financial Strength and Liquidity	a) Adjusted days liquidity on hand (3-year avg) (days)	Baa	69
	b) Debt ratio (3-year avg) (%)	Baa	97%
	c) Fixed obligation charge coverage ratio (3-year avg) (x)	Baa	1.21
Material Asset Event Risk	Does agency have event risk?	No	
Notching Factors		**Notch**	
	1 - Contractual Structure and Legal Environment	-0.5	
	2- Participant Diversity and Concentration	0	
	3 - Construction Risk	0	
	4 - Debt Service Reserve, Debt Structure and Financial Engineering	0	
	5 - Unmitigated Exposure to Wholesale Power Markets	0	
Scorecard Indicated Rating:		**Ba3**	

Source: Moody's Investors Service

Ratings

Exhibit 2

Category	Moody's Rating
OHIO VALLEY ELECTRIC CORP	
Outlook	Stable
Sr Unsec Bank Credit Facility	Ba1
Senior Unsecured	Ba1

Source: Moody's Investors Service

REPORT NUMBER 1154297

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of 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.	U-20224 ALJ Dennis Mack

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PROOF OF SERVICE

On the date below, an electronic copy of **PUBLIC Version of the Direct Testimony of Devi Glick on behalf of Sierra Club with Exhibits SC-1 through SC-20** was served on the following:

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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: October 23, 2020

By: Breanna Thomas

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