November 16, 2020

Connie Graley, Executive Secretary
Public Service Commission of West Virginia
201 Brooks Street, PO Box 812
Charleston, WV 25323-0812

Re: *Monongahela Power Company and The Potomac Edison Company, Petition to Initiate a General Investigation to Determine Reasonable Rates and Charges on and after January 1, 2021*, Case No. 20-0665-E-ENEC

Dear Ms. Graley:

Please find enclosed for filing on behalf of Solar United Neighbors and West Virginia Citizen Action Group in the above-referenced case, the original and twelve copies of the PUBLIC VERSION of the Direct Testimony of Tyler Comings. Please note that this same testimony is being filed contemporaneously in Case No. 20-0666-E-4435T.

Copies of the public version of this testimony are being served upon all parties of record. The confidential version is being served on the Companies, and those parties that have executed an appropriate protective agreement with the Companies.

Please contact me if you have any questions concerning this filing.

Respectfully,

Emmett Pepper
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Counsel for West Virginia Citizen Action Group and Solar United Neighbors

Enclosures

November 16, 2020

Connie Graley, Executive Secretary
Public Service Commission of West Virginia
201 Brooks Street, PO Box 812
Charleston, WV 25323-0812

Re: *Monongahela Power Company and The Potomac Edison Company, Joint Application for Modernization and Improvements Program for Coal-Fired Boilers Transaction and Related Relief*, Case No. 20-0666-E-4435T

Dear Ms. Graley:

Please find enclosed for filing on behalf of Solar United Neighbors and West Virginia Citizen Action Group in the above-referenced case, the original and twelve copies of the PUBLIC VERSION of the Direct Testimony of Tyler Comings. Please note that this same testimony is being filed contemporaneously in Case No. 20-0665-E-ENEC.

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PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

MONONGAHELA POWER COMPANY and	)	
THE POTOMAC EDISON COMPANY,	)	**Case No. 20-0665-E-ENEC**
Petition to initiate a General Investigation to	)	
determine reasonable rates and charges on and	)	
after January 1, 2021	)	

MONONGAHELA POWER COMPANY and	)	
THE POTOMAC EDISON COMPANY,	)	**Case No. 20-0666-E-4435T**
Joint application for modernization and	)	
improvements program for coal-fired boilers	)	
under the provisions of Enrolled Committee	)	
Substitute for House Bill 4435	)	

Direct Testimony of
Tyler Comings

Public Version

On Behalf of
West Virginia Citizen Action Group and
Solar United Neighbors

November 16, 2020

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I. INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Tyler Comings. I am a Senior Researcher at Applied Economics Clinic, located at 1012 Massachusetts Avenue, Arlington, Massachusetts.

Q. Please describe Applied Economics Clinic.

A. The Applied Economics Clinic is a 501(c)(3) non-profit consulting group housed at Tufts University's Global Development and Environment Institute. Founded in February 2017, the Clinic provides expert testimony, analysis, modeling, policy briefs, and reports for public interest groups on the topics of energy, environment, consumer protection, and equity, while providing on-the-job training to a new generation of technical experts.

Q. Please summarize your work experience and educational background.

A. I have 14 years of experience in economic research and consulting. At Applied Economics Clinic, I focus on energy system planning, costs of regulatory compliance, wholesale electricity markets, utility finance, and economic impact analyses. I have provided testimony on these topics in West Virginia, Arizona, Colorado, the District of Columbia, Hawaii, Indiana, Kentucky, Maryland, Michigan, Missouri, New Jersey, New Mexico, Ohio, Oklahoma, and Nova Scotia (Canada). I am also a Certified Rate of Return Analyst (CRRA) and member of the Society of Utility and Regulatory Financial Analysts (SURFA).

I have provided expertise for many public-interest clients including: American Association of Retired Persons (AARP), Appalachian Regional Commission, Citizens

Action Coalition of Indiana, City of Atlanta, Consumers Union, District of Columbia Office of the People's Counsel, District of Columbia Government, Earthjustice, Energy Future Coalition, Hawaii Division of Consumer Advocacy, Illinois Attorney General, Maryland Office of the People's Counsel, Massachusetts Energy Efficiency Advisory Council, Massachusetts Division of Insurance, Michigan Agency for Energy, Montana Consumer Counsel, Mountain Association for Community Economic Development, Nevada State Office of Energy, New Jersey Division of Rate Counsel, New York State Energy Research and Development, Nova Scotia Utility and Review Board Counsel, Rhode Island Office of Energy Resources, Sierra Club, Southern Environmental Law Center, U.S. Department of Justice, Vermont Department of Public Service, West Virginia Consumer Advocate Division, and Wisconsin Department of Administration.

I was previously employed at Synapse Energy Economics, where I provided expert testimony and reports on coal plant economics and utility system planning. Prior to that, I performed research on consumer finance and behavioral economics at Ideas42 and conducted economic impact and benefit-cost analysis of energy and transportation investments at EDR Group.

I hold a B.A. in Mathematics and Economics from Boston University and an M.A. in Economics from Tufts University.

My full resume is attached as Exhibit TC-1.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of West Virginia Citizen Action Group and Solar United Neighbors (collectively, "CAG/SUN").

Q. Have you testified before the West Virginia Public Service Commission previously?

A. Yes. In 2017, I submitted testimony on Monongahela Power Company's ("Mon Power") proposed acquisition of the Pleasants Power Station in Case No. 17-0296-E-PC.

Q. What is the purpose of your testimony?

A. My testimony focuses on the economic value of the Fort Martin and Harrison Power Stations. My analysis informs Mon Power and The Potomac Edison Company's ("the Companies") requested rate recovery for certain capital and operation and maintenance ("O&M") costs at these plants (in Case No. 20-0666-E-4435T), and the reasonableness of the costs and revenues related to Mon Power's operation of these plants (in Case No. 20-0665-E-ENEC).

Q. Please briefly summarize your findings and recommendations.

A. After reviewing the Companies' filings and discovery responses in these two cases, I have found that the costs of the Fort Martin and Harrison generating units are higher than the economic value they provide to ratepayers. The economics of the Fort Martin units are particularly challenged. The Harrison and Fort Martin units have had negative net revenues in recent years, and, based on Mon Power's forecasts, these units are mostly expected to continue operating at a loss through at least 2024 (the last year of my assessment). It is my understanding that, although the Commission is not considering a full modernization and improvement program ("MIP") in this case, the Companies have been invited to submit one in the future.[1] Given the poor economic outlook of the Fort Martin and Harrison units, I recommend that the Companies be directed to submit a rigorous, forward-looking economic analysis of these units (e.g., a net present value analysis) with any future proposal for a MIP. For these reasons, and as explained further below, I also recommend that the Commission not approve the Companies' current request to implement a $5 million surcharge in 2021.

I have also found that, during the ENEC review period (7/1/18-6/30/20), Mon Power frequently operated the Fort Martin and Harrison units at a loss, a pattern that Mon Power projects [[[redacted]]]. Many of these operational losses appear to be the result of Mon Power's practice of "self-scheduling" these units, which requires PJM to take some of the units' power regardless of whether their dispatch costs are higher than energy prices. These operational losses could be mitigated if Mon Power committed these units into PJM on an economic basis. And because it appears that Mon Power sometimes self-schedules these units to satisfy minimum take obligation under its coal supply contracts, Mon Power should continue its efforts to reduce those contractual obligations.

Q. What information did you review in preparing your testimony in this case?

A. I reviewed the Companies' testimony, exhibits, discovery responses, and publicly available data from the Energy Information Administration (EIA) and FERC Form 1.

[1] Case Nos. 20-0665-E-ENEC & 20-0666-E-4435T, Oct. 6, 2020 Commission Order at pages 4, 7.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring exhibits identified as Exhibits TC-1 through TC-15.

II. ISSUES RELATED TO FORT MARTIN AND HARRISON IN THESE TWO CASES

Q. Please describe the Fort Martin and Harrison Power Stations.

A. The Fort Martin and Harrison plants are owned and operated by Mon Power. Collectively, there are five coal-fired generating units at these plants. The capacity and age of these five units is listed below:[2]

Fort Martin Unit 1: 552 megawatts (MW), 53 years old;
Fort Martin Unit 2: 546 MW, 52 years old;
Harrison Unit 1: 662 MW, 48 years old;
Harrison Unit 2: 661 MW, 47 years old;
Harrison Unit 3: 661 MW, 46 years old.

Q. How long does Mon Power plan on operating these units?

A. At least into the next decade. The Companies have stated that their forthcoming integrated resource plan ("IRP") predicts that the units will operate at least through 2034 or 2035.[3] None of these units has a specified retirement date.[4]

Q. Have the Companies ever evaluated the economics of retiring any of these units?

A. No. The Companies have never performed nor solicited any such analyses.[5]

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[2] Case No. 20-0665, Murphy Direct Testimony, Ex. ELM-1. Note: for brevity and readability, when citing discovery responses and witness testimony I have shortened the relevant docket numbers to "20-0665" and "20-0666."
[3] Exhibit TC-2 (Case No. 20-0665, resp. to SC-2.9) ("The upcoming IRP to be filed in December predicts under current regulation that the plants will operate through the 15-year IRP forecast period.") Depending on whether the IRP forecast starts in 2020 or 2021, this 15-year period would end in 2034 or 2035.
[4] Exhibit TC-3 (Case No. 20-0666, resp. to CAG-2.11(a)).
[5] Exhibit TC-4 (Case No. 20-0666, resps. to EUG-1.3, CAG-2.10).

Q. Please briefly describe the Companies' ENEC filing (Case No. 20-0665-E-ENEC).

A. The Companies' witnesses state that the general purpose of the ENEC proceeding is for the Companies to recover fuel, purchased power, purchased transmission costs, and PJM costs, net of revenue credits.[6] In their ENEC filing, the Companies report that during the review period (June 30, 2018, through June 30, 2020) they had an over-recovery of $29,317,624, "due mainly to lower fuel costs and realizing the full effect of the termination of the Morgantown Energy Associates PURPA contract."[7] The Companies further report they anticipate a further $43,589,240 over-recovery in 2021.[8] With respect to fuel costs specifically, Companies' witness Mark Valach testified that fuel prices decreased because of early coal plant retirements, low power prices, decreased demand, and increased competition from gas and renewables.[9] Mr. Valach predicts that coal generation will continue to be "increasingly challenged" by gas and renewable energy through 2023, and that coal producers and buyers will continue to drop out of the market.[10]

In light of this $72.9 million over-recovery, the Companies have proposed a decrease in ENEC rates for 2021. However, the Companies wish to offset that decrease by recovering $7.4 million of environmental compliance costs, as well as approximately $10.5 million in costs incurred due to COVID-19; the lion's share of these COVID costs (about $8.6

[6] *See, e.g.,* Case No. 20-0665, Valdes Direct Testimony at page 4.
[7] Case No. 20-0665, Companies' August 28, 2020 Application, cover letter at page 1; *see also* Colflesh Direct Testimony at page 7; Valdes Direct Testimony at page 4.
[8] Case No. 20-0665, Valdes Direct Testimony at page 4.
[9] Case No. 20-0665, Valach Direct Testimony at page 4.
[10] *Id.* at pages 5-6.

million) are due to uncollected bills from customers who were unable to pay due to the pandemic.[11]

Q. What is the Commission considering in Case No. 20-0666-E-4435T?

A. In Case No. 20-0666-E-4435T, the Commission is considering the Companies' request to collect a $5 million surcharge (the "MIP surcharge") in calendar 2021.[12] This proposed surcharge was calculated based on certain costs that Mon Power incurred, or plans to incur, between 2018 and 2021 to satisfy the Mercury and Air Toxics Standards ("MATS"), and the Cross-State Air Pollution Rule ("CSAPR").[13]

Q. Is the Commission considering a full modernization and improvement program in this case?

A. No. In their initial application, the Companies proposed a "modernization, upgrade, and improvement plan," or MIP, that included $247.6 million of capital and O&M spending over an 8-year period, running from 2018 through the end of 2025.[14] The Companies' proposed spending included $139 million of capital expenditures for retrofits at Harrison

[11] Case No. 20-0665, Colflesh Direct Testimony, Ex. SMC-13.
[12] Case Nos. 20-0665-E-ENEC & 20-0666-E-4435T, Oct. 6, 2020 Commission Order at page 7 (ordering "that the Commission will consider the $5 million request for MATS and CSPAR recovery in Case No. 20-0665-E-4435T and will not consider the MIP"); *see also* Oct. 19, 2020 Commission Order at page 5.
[13] *See generally* Case No. 20-0666, Valdes Direct Testimony, Exhibits RV-2 through RV-9 (showing that the MIP surcharge for 2021 was calculated based on including capital projects completed, or anticipated to be completed, in the years 2018-2021).
[14] *See* Case No. 20-0666, Sendro Direct Testimony, Ex. DVS-1 (listing $247.6 million of capital and O&M expenditures). The Companies recently filed a revised version of this exhibit that changed the timeline for some of these capital expenditures. *See* Ex. DVS-1A (filed Nov 4, 2020). CAG/SUN requested certain information about the proposed MIP; the Companies' responses to some of those questions are attached as Exhibit TC-5 (Case 20-0666, resps. to CAG-1.11 & 1.15, request CAG-1.14, and resp. to CAG-2.3).

and Fort Martin to bring the plants into compliance with U.S. EPA's Effluent Limitation Guidelines ("ELGs").

But on October 6, 2020, the Commission ordered that it "will consider the $5 million request for MATS and CSPAR recovery in Case No. 20-0665-E-4435T and will not consider the MIP."[15] The Commission explained that it "will not be considering in this docket a full MIP or any portion of the ELG expenses or plan."[16] In doing so, the Commission noted that the Companies "may make a future filing to request Commission approval of a coal-fired boiler MIP including the plans for ELG compliance and cost consideration."[17] So although in this case the Commission is only considering the Companies' request for rate recovery of $5 million, the Companies may file a future case in which they seek approval for a full MIP, including the estimated $139 million of ELG costs.

Q. How are the two current cases relevant to current and future spending on these units?

A. The five generating units at Harrison and Fort Martin plants can have a significant impact on the ratepayers' bottom line even though these units do not directly serve customers. The units operate in and serve the PJM market at-large, the same marketplace where Mon

[15] Case Nos. 20-0665-E-ENEC & 20-0666-E-4435T, Oct. 6, 2020 Commission Order at page 7; *see also* Oct. 19, 2020 Commission Order at page 5 ("The Commission previously held that it would not consider a full MIP or the ELG costs based on the Companies' representation that they seek rate recovery only for approximately $5 million that is wholly attributable to a continuation of MATS and CSAPR costs previously approved by the Commission in Case No. 16-1121-E-ENEC.").
[16] Oct. 6, 2020 Commission Order at page 4.
[17] *Id.* at page 4.

Power simultaneously procures its energy and capacity needs for customers.[18] While the Harrison and Fort Martin units earn substantial revenues in the PJM energy, capacity, and ancillary services markets (which are credited to customers), these units also incur significant costs which are recovered in customers' rates.

For example, during the 2017 through 2020 timeframe, Mon Power spent between [[[redacted]]] annually on capital projects at each plant, incurred non-fuel O&M costs between [redacted] annually, and incurred substantial fuel costs.[19] Meanwhile, the Companies' initial application in Case 20-0666-E-4435T sought expedited rate recovery for a $247 million capital and O&M spending program, and although the case currently only involves a $5 million rate recovery request for 2021, the Companies may seek approval of a larger spending program in the future.[20]

The two cases thus offer an opportunity to evaluate the economics of the Fort Martin and Harrison units, and to consider how their economic position should inform decision-making in both the short- and long-term. Because ENEC proceedings are typically filed annually, and include a major focus on fuel costs, this ENEC case (20-0665) provides an opportunity to consider whether the units' operation or Mon Power's coal procurement

[18] As the Companies acknowledged in discovery, all of the Companies' load is purchased from the PJM energy markets, and all of Mon Power's generation is sold into those markets. Exhibit TC-6 (Case No. 20-0665, resp. to SC-1.12).

[19] Confidential Exhibit TC-7 (Case No. 20-0666, CAG-1.13 CONFIDENTIAL 10.21 and CAG 1.14 CONFIDENTIAL 10.21) (identifying annual capital and O&M costs, with an estimate for the last four months of 2020); Case No. 20-0665, Valach Direct Testimony at page 5 ("During the review period, Mon Power consumed more than 14.6 million tons of coal at a cost of $746 million.").

[20] Case Nos. 20-0665-E-ENEC & 20-0666-E-4435T, Oct. 6, 2020 Commission Order at pages 4, 7; *see also id.* at page 4 ("The Companies may make a future filing to request Commission approval of a coal-fired boiler MIP including the plans for ELG compliance and cost consideration.")

practices can be modified in ways that improve ratepayer value. The Companies' witnesses have recognized the importance of this, stating that "Mon Power continues to evaluate future fuel options to enhance plant economics."[21]

In the ENEC case, the Commission is considering a two-year review period (July 1, 2018, through June 30, 2020), and the Companies' witnesses have provided data about the recent performance of the Fort Martin and Harrison units, as well as a near-term forecast of the units' costs and revenues. And in both cases, the Companies have provided information about the generating units' revenues, capital costs, and O&M expenses, as well as some information about potential future capital expenditures.[22] All of this information paints a picture of the units' economics, and can inform major decisions that impact ratepayers, such as whether a future proposal for a multi-year MIP would be just, reasonable, and prudent for the Companies' customers. The units' economics also inform long-term questions, such as how much longer these units should remain in service.

Q. Please describe your findings and recommendations.

A. Based on my review of the Companies' filings and discovery responses in these two cases, I conclude that:

1. **The costs of the Fort Martin and Harrison units are higher than the economic value they provide to ratepayers.** In my review, I assessed the overall economics of the Fort Martin and Harrison units by determining their annual net revenue – i.e., the revenue earned from energy, capacity, and ancillary services, minus their costs

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[21] Case No. 20-0665, Valach Direct Testimony at page 5.

[22] *See, e.g.*, Case No. 20-0665, Murphy Direct Testimony, Ex. ELM-3; Case No. 20-0666, Sendro Direct Testimony, Ex. DVS-1A.

to ratepayers (both fixed costs, such as capital expenditures, and variable costs, such as fuel). In performing this assessment, I used actual historical revenues and costs, as well as the Companies' projections of future costs and revenues. I show that the units' costs to ratepayers far exceed their economic value for each of the years 2019 through 2024. The economics of Fort Martin are particularly challenged; per MW of capacity, the Fort Martin units have imposed greater costs on ratepayers than the Harrison units in recent years [[[redacted]]]

2. **The Fort Martin and Harrison units are projected to earn much less energy market revenue than Mon Power previously forecasted.** In discovery, the Companies provided energy revenue projections for Fort Martin and Harrison that were prepared in 2019 and 2020. Compared to last year's projection, the projected energy revenue from these five units has decreased by [redacted] over the 2020 through 2023 timeframe.[23] This drastic decrease in revenue expectations reinforces the poor future economic outlook for these units.

3. **Mon Power has frequently operated the units at a loss in recent months**. During the ENEC review period, Mon Power frequently "self-scheduled" the Fort Martin and Harrison units. By committing these units as "must run" in the PJM energy market (i.e. self-scheduling), Mon Power ensured that the units would be online (and thus burn fuel). Mon Power chose to do this often rather than allowing PJM to commit them on an economic basis (i.e. "economic commitment"). It appears that Mon Power's practice has resulted in operational losses at the units in recent months. For the ENEC review period, I compared the monthly revenues earned by the units when generating (energy and ancillary services revenues) to their variable costs (fuel and variable O&M). I found that these units' energy revenues are often exceeded by their variable costs. Mon Power projects that this [[[redacted]]].

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[23] *See infra* note 33.

In light of these conclusions, I recommend the following:

1. **If the Companies submit a comprehensive modernization and improvement program (MIP) in a future case, they should be required to justify the cost of that program through a rigorous, forward-looking economic analysis of the Fort Martin and Harrison units.** Despite the poor current and future economics of these generating units, it appears that Mon Power plans to continue operating them until at least the mid-2030s. The Companies' customers might benefit if, instead of incurring additional capital expenditures, Mon Power retired one or more of these generating units. To enable the Commission and the parties to evaluate the reasonableness of a future MIP proposal, the Commission should direct the Companies to submit, as part of any future MIP filing involving the Fort Martin and Harrison units, a rigorous, forward-looking economic analysis of the remaining life of those units. Such analysis should evaluate the net present value (NPV) of alternative retirement dates for each unit and identify capital and O&M spending that could be avoided if one or more units retired.

2. **The Commission should not approve the Companies' request to implement a $5 million surcharge in 2021.** In Case 20-0666-E-4435T, the Companies are seeking expedited recovery of certain capital and O&M costs through the collection of a $5 million surcharge in 2021.[24] This surcharge is based, in part, on MATS and CSAPR capital expenditures that the Companies incurred, or plan to incur, at Fort Martin and Harrison over the 2018-21 timeframe. The Companies have requested these expenditures be given preferential rate treatment, but the reasonableness and prudence of these investments has not been shown. The Companies did not conduct an economic analysis to justify these investments relative to other alternatives, such as retiring any of the units. Additionally, in the future the Companies might propose a new MIP that seeks recovery of ELG expenditures and post-2021 CSAPR and

[24] The Companies' original application requested this $5 million of cost recovery under the State's coal boiler modernization statute, West Virginia Code § 24-2-1*l*.

MATS costs; to avoid piecemeal consideration of these costs, the 2018-21 costs should be evaluated as a part of that larger spending program. Therefore, the Commission should deny the Companies' request to collect a $5 million surcharge in 2021. If the Companies seek recovery of these investments in further cases, they should have to establish that the spending was in the public interest; they have not done so.

3. **The Companies should report on coal contract obligations and unit commitment practices in future ENEC cases.** Mon Power's self-scheduling of the Fort Martin and Harrison units has resulted in monthly losses during the review period. Mon Power has acknowledged that its "self-scheduling" practice is due in part to its coal supply contract obligations. Mon Power should continue reducing contract obligations that have motivated this self-scheduling practice and should work proactively to reduce operation of units during periods of low power prices (such as by economically committing them into the PJM). The Commission should direct the Companies, as part of the initial filing in their next ENEC case, to report back on: 1) the status of Mon Power's efforts to reduce its coal contract obligations; 2) steps Mon Power is taking to reduce the operation of these units during periods of low power prices; and 3) an update on Mon Power's commitment process, including an assessment of the impact its coal contract obligations had over the 2020-21 review period.

4. **Mon Power should provide mid-term forecasts of its generating units' costs in future ENEC cases.** The reasonableness of the fuel expenses collected through the ENEC is informed, in part, by Mon Power's management and operation of its generation fleet. This is implicitly acknowledged in each ENEC filing, with the Companies providing a one-year forecast of the generating units' fuel burn and information about capital expenditures planned during the following year.[25] But these costs and revenues, especially capital spending strategies and O&M expenses,

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[25] *See, e.g.*, Valach Direct Testimony at page 6 & Exs. MJV-2(b), (c); Murphy Direct Testimony, Ex. ELM-3.

are better evaluated over a longer timeframe. Because such data would offer the Commission and other parties a more holistic view of the units' future value than the current one-year projection, the Commission should direct Mon Power to provide a four- or five-year forecast of its generating units' costs with future ENEC filings.

III. THE FORT MARTIN AND HARRISON UNITS HAVE A POOR CURRENT AND FUTURE ECONOMIC OUTLOOK.

Q. Please summarize your assessment of the net revenue of the Fort Martin and Harrison units.

A. The current and future outlook for these units is unfavorable and should at least call into question the reasonableness of future large capital investments in these units. The economics of the Fort Martin plant, which is smaller and older than Harrison, are particularly poor. My economic analysis relies on historical and forecasted data that the Companies provided in discovery. I find that the units' current and future costs substantially outweigh their economic value to ratepayers.

A. Fort Martin and Harrison's Revenues Are Not Expected to Cover Their Costs.

Q. Please describe how you evaluated the economics of the Fort Martin and Harrison units.

A: The Companies' ratepayers are significantly impacted by the economics of the Fort Martin and Harrison units. The units do not serve the Companies' customers directly, but they sell energy, capacity, and ancillary services into the PJM wholesale markets, and those revenues are credited to ratepayers for the units' performance in those markets. Through the ENEC and base rates, the Companies' customers pay for Mon Power's costs of owning and operating the units. Thus, ratepayers benefit from the Fort Martin and Harrison units to the extent that the units' revenues exceed their costs.

I evaluated the net revenue of the units, which I define as the revenues that the units collect from the PJM wholesale market minus the costs of owning and operating the units. If a unit or plant's revenue exceeds its costs, then it is said to have positive net revenue; conversely, if its costs exceed its revenue the unit or plant has negative net revenue.

The net revenue of the units includes the following:

+ Energy revenue from generation sold to PJM day-ahead and real-time markets
+ Capacity revenue earned by being available to serve PJM peak load
+ Ancillary services revenue from providing PJM grid regulation and reserves
- Fuel costs
- Fixed and variable O&M
- Capital costs
- Taxes

Q. How did you include capital costs at the units?

A. In calculating net revenue, I considered the capital costs in two different ways: 1) in terms of capital revenue requirements (equal to depreciation and return on rate base); and 2) in terms of annual capital spending. The former reflects the capital costs that ratepayers pay in that year through rates. I recognize that these revenue requirements include previously completed capital projects at the units that would be considered "sunk" costs because they cannot be reversed. To address that concern, I also present the net revenue concept with the capital costs as-spent. These do not include previously incurred capital expenditures, only those incurred in each year. My analyses are looking at a limited, short-term timeframe based on data provided by the Companies. Neither of my analyses is intended to take the place of a long-term, forward-looking analysis of the units, which would include all revenue requirements (including capital revenue requirements).

Q. What did you find for the current and future net revenue of Fort Martin and Harrison?

A. The net revenue of the Fort Martin and Harrison plants was positive in 2018 and negative in 2017 and 2019. Both plants are expected to have negative net revenues in each of the years 2020 through 2024—the latest year of the revenue projections provided by the Companies. When the generating units are considered individually, all five units had positive net revenue in 2018, and [[[redacted]]]. Both Fort Martin units and Harrison unit 1 had negative net revenue in 2017 and 2019, with Harrison units 2 and 3 positive in 2017, and slightly positive in 2019.

Figure 1 shows the net revenue for each plant, and Table 1 shows the breakdown by unit. When the five units are considered together, the net revenue shown for 2020 is [[[redacted]]], with the most losses in later years projected to occur [[[redacted]]]. These values represent how much ratepayers are overpaying for the units because the market revenue is not expected to cover the units' costs.

Figure 1: Net Revenue of Fort Martin and Harrison by Plant (Using Capital Revenue Requirements, $mil) (Confidential)[26][[

[redacted]

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[26] For January 2014 through August 2020, I obtained the figures for O&M, fuel cost, energy revenue, capacity revenue, and ancillary services revenue from Case No. 20-0666, CAG-1.13 CONFIDENTIAL 10.21. For September 2020 through December 2024, I obtained figures for O&M, fuel cost, energy revenue, capacity revenue, and ancillary services revenue from Case No. 20-0666, CAG-1.14 CONFIDENTIAL 10.21. I obtained the figures for depreciation expense, gross and net plant balance from Case No. 20-0666, CAG-1.16 Attachment A (attached as Exhibit TC-8), and Revised CAG-1.17 Attachment A CONFIDENTIAL (attached as Confidential Exhibit TC-9). I obtained the figures for property and business and occupancy (B&O) taxes from Case No. 20-0666, CAG-1.16 Attachment B and Revised CAG-1.17 Attachment B CONFIDENTIAL. Finally, I obtained figures for pre-tax rate of return from Case 20-0666, Valdes Direct Testimony, Ex. RV-1 for 2021, and CAG-3.5 Attachment A Updated (attached as Exhibit TC-10) for 2017 through 2020. For the latter, data was only provided for the individual companies. I estimated the pre-tax rate of return for the combined companies using the capital structure, costs of debt and equity, and income tax rates provided.

Much of the cost information was provided at the unit level, in which case I used the unit-level information directly provided by the Companies. However, some of the data was only provided at the plant level. To allocate those costs to individual units, I used the following assumptions: (i) I allocated each unit's O&M costs by its percentage of the plant's annual generation; (ii) I allocated fuel costs per unit based on the fuel cost reported by plant multiplied by the fuel burned per unit (iii) I allocated plant property taxes to each unit based on its gross plant balance; (iv) when not provided at the unit level, I allocated B&O taxes to each unit based on its share of 2020 taxes; (v) for costs attributed to plantwide common areas or systems ("commons"), I allocated each unit's share of those costs based on that unit's share of the plant's overall capacity.

Table 1: Net Revenue of Fort Martin and Harrison by Unit (Using Capital Revenue Requirements, $mil) (Confidential)[27][[

[redacted]

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Q. Did you also calculate the net revenue per unit of capacity, to control for the different sizes of the units?

A. Yes. There is clearly variation in the overall net revenues among the units, shown above. Controlling for unit size gives a clearer picture of the relative economics between the units, and the two plants relative to each other. The net revenue per kW of capacity of each unit is shown below in Table 2. This shows that Fort Martin had a lower net revenue per kW than Harrison from 2017 to 2019—and thus has been more costly than Harrison on a per capacity basis for this period. [[[redacted]]] When looking at the economics of individual units for 2020 and later years, [[[redacted]]] are the most costly.

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[27] *See generally id.*

Table 2: Net Revenue of Fort Martin and Harrison by Unit, Per Unit of Capacity (Using Capital Revenue Requirements, $ per kW) (Confidential)[28] [[

[redacted]

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Q. Do the capital requirements used above for Fort Martin include all capital expenditures being recovered in rates?

A. No. The Fort Martin revenue requirements information provided by the Companies excluded the costs of $450 million of environmental control bonds used to finance construction and operation of the flue gas desulfurization (FGD) or "scrubbers" that were installed at the plant in 2009.[29] Therefore, the costs currently paid by ratepayers for Fort Martin are understated above. If those costs were factored in, the net revenues would be worse.

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[28] *See generally id.* Capacity is based on unforced capacity ("UCAP") provided in CAG-1.13 CONFIDENTIAL 10.21 (attached as Confidential Exhibit TC-7).

[29] Case No. 20-0666, CAG-1.16 Attachment A (Companies' note that the "Ft. Martin data excludes securitized scrubbers"). It is my understanding that in January 2007, the Commission authorized the Companies to finance construction and operation of a flue gas desulfurization system (wet scrubber) and related facilities at Fort Martin through $450 million in Environmental Control Bonds. Case Nos. 05-0402-E-CN and 05-0750-E-PC, Jan. 17, 2007 Commission Order.

Q. Did you also look at net revenue of the Fort Martin and Harrison units using capital costs as-spent, instead of capital revenue requirements?

A. Yes. As an alternative analysis, I replaced the capital revenue requirements with annual dollars spent on capital investments at the units. This approach, which omits sunk costs, does not reflect how such costs would be recovered in rates. Using this method does not count depreciation for capital projects done in prior years, nor does it include the rate of return on Mon Power's rate base. Using capital costs as-spent, the net revenue of the Fort Martin plant is projected to be [[[redacted]]]. At Harrison, the net revenue is [[[redacted]]]

Figure 2: Net Revenue of Fort Martin and Harrison by Plant (Using Capital Costs As-spent, $mil) (Confidential)[30][[

[redacted]

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Table 3: Net Revenue of Fort Martin and Harrison by Unit (Using Capital Costs As-spent, $mil) (Confidential)[31] [[

[redacted]

[30] *See generally supra* note 26. For the as-spent capital expenditures for January 2014 through August 2020, I used the figures provided in No. 20-0666, CAG-1.13 CONFIDENTIAL 10.21. For as-spent capital costs from September 2020 through December 2024, I used the figures in No. 20-0666, CAG-1.14 CONFIDENTIAL 10.21. Capital revenue requirements (depreciation and return on ratebase) are not included.

[31] *See generally id.*

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Q. What were the results of this alternative approach for net revenues per unit of capacity?

A. Similarly to what I reported above on a per kW basis, Fort Martin, from 2017 through 2019, has been less economic than Harrison—as shown in Table 4. [[[redacted]]] The unit-by-unit results fluctuate from year-to-year because capital spending does so. However, in most years shown, [[redacted]]] is the least economic.

Table 4: Net Revenue of Fort Martin and Harrison by Unit, Per Unit of Capacity (Using Capital Costs As-spent, $ per kW) (Confidential)[32] [[

[redacted]

]]

Q. Are there other reasons to think that the economics of the Fort Martin units are poor?

A. Yes (including the discussion below in Section III.B). Moreover, as an illustrative exercise, I calculated the Fort Martin and Harrison net revenues *without* any capital

[32] *See generally id.* Capacity is based on UCAP. *See* Confidential Exhibit TC-7 (CAG-1.13 CONFIDENTIAL 10.21).

spending. This is an artificially conservative calculation (i.e., making the units appear more economic than they really are), because capital expenditure is a major cost component. The results show that the net revenues for both Fort Martin units would [[redacted]]] and [[redacted]]] when capital costs are excluded entirely. The Harrison units would be [[redacted]]] if capital costs are excluded.

B. Mon Power's Projection of the Plants' Energy Revenues Has Decreased Drastically.

Q. Has Mon Power's projections of the units' energy revenue changed in the last year?

A. Yes, substantially. In both 2019 and 2020, Mon Power projected the energy, capacity, and ancillary services revenue of the Fort Martin and Harrison units over a four-year period. The projected energy revenues reflect Mon Power's expectation about the future revenue these units will earn from selling their power into the PJM energy market. I compared this year's energy revenue projection to the one Mon Power prepared in 2019. For Fort Martin and Harrison combined, the expected revenue over the 2020-2023 timeframe has decreased by [redacted].[33] This represents a drastic decrease in the units' overall value. [[redacted]

[33] Case No. 20-0665, resp. to CAG-1.11 & "CAG Data Request 1st set Q11.a backup – CONFIDENTIAL" spreadsheet; Case No. 19-0785-E-ENEC (previous ENEC case), resp. to CAG-1.10 & "CAG Data Request 1st set Q10 Attachment A-2nd request CONFIDENTIAL" spreadsheet. These spreadsheets are voluminous, but excerpts from both are attached as Confidential Exhibit TC-11. Data for the 2020 projection includes actual revenue reported by Mon Power through August and Mon Power's projection for the rest of the year. Note: [[redacted]]]

[redacted]]].[34]

The change in Mon Power's energy revenue projections at the plant level are shown in Figure 3 and Figure 4. Notably, Mon Power expects Fort Martin to earn [[[redacted]]] the company had previously projected for the plant in 2020.[35] Harrison is expected to earn [[[redacted]]] of its previously projected 2020 energy revenue.[36] As the figures below show, however, Mon Power is not expecting [[[redacted]]] through 2024—the latest year projected.

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[34] Confidential Exhibit TC-7 (Case No. 20-0666, CAG-1.13 CONFIDENTIAL 10.21).
[35] *Supra* note 33.
[36] *Id.*
[37] In the ENEC application, Companies' witnesses Mancuso and Liang-Nicol testified that the COVID-19 pandemic lowered demand and power prices in the first quarter of 2020. Case No. 20-0665, Mancuso Direct Testimony at page 4; Liang-Nicol Direct Testimony at page 3. The Companies' application makes no prediction as to the future impact of COVID-19 on power prices or fuel prices.

Figure 3: Fort Martin Energy Revenue ($mil) (Confidential)[38] [[

[redacted]

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Figure 4: Harrison Energy Revenue (Confidential) ($mil)[39][[

[redacted]

[38] *Supra* note 33.
[39] *Id.*

]]

Q. What does this drop in projected energy revenues tell us about the economic health of the Fort Martin and Harrison units?

A. Although these energy revenue projections do not consider all of the units' costs and revenue—I provide that more holistic assessment in Section III.A above—the anticipated drop in this revenue stream raises further questions about the units' overall economic health. Such a dramatic shift in expectations should have led Mon Power to reassess these units' future operations rather than maintaining business-as-usual.

C. Discussion

Q. How should your evaluation of Fort Martin and Harrison's net revenue influence decision-making on these units?

A. My analyses above, which rely on the Companies' own data, show that the units are often expected to produce negative net revenue over the next several years. By comparing the costs per unit of capacity, I show that historically the Fort Martin plant has been less economic than the Harrison plant, and is expected to [[[redacted]]]. However, my calculations are limited to the near future because forecasts were provided through 2024. The results discussed above demonstrate the need for a rigorous, forward-looking, longer-term economic assessment that estimates the net present value (NPV) of revenues and costs for the units.

Q. Has Mon Power evaluated alternatives to investing further capital in the Fort Martin and Harrison units?

A. No. Prior to making major capital expenditures on a generating plant, a prudent utility should evaluate whether such expenditures are just, reasonable, and prudent, such that ratepayers should be asked to cover the costs of that spending. A utility should also perform such evaluation before embarking on a large, multi-year capital spending program. In Case No. 20-0666-E-4435T, the Commission is considering a $5 million surcharge to ratepayers in 2021, which is based, in part, on MATS and CSAPR capital projects that have been or will be completed between 2018-21.[40] The Commission also stated that the Companies may file a future request for approval of a comprehensive modernization and improvement plan (MIP).[41] If the Companies file such a request, I presume they would seek rate recovery for the MATS, CSAPR, and ELG capital projects Mon Power seems to have planned for 2022 through 2025.[42]

If the Companies file a future MIP request, that filing should evaluate whether the continued operation of the units is the most economic path for ratepayers. As my analysis shows, [[[redacted]]], with the economics of the Fort Martin units particularly challenged. Despite that, there is no evidence that Mon Power has ever considered whether retirement of one or more these units would be more cost-effective than continuing to incur capital and O&M costs at them.[43] Without rigorous economic analysis comparing the impact to ratepayers from retirement versus continued operation, Mon Power would be asking for approval and expedited recovery of costs that have not been economically justified.

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[40] *Supra* note 13.
[41] Case Nos. 20-0665-E-ENEC & 20-0666-E-4435T, Oct. 6, 2020 Commission Order at page 4.
[42] These projects were listed in witness Sendro's exhibit DVS-1 (which the Companies recently amended – Ex. DVS-1A).
[43] *See* Exhibit TC-4 (Case No. 20-0666, resp. to CAG-2.6) (confirming that "no retirement analysis of any of the Mon Power coal units has been conducted"). In fact, Mon Power has never evaluated the potential retirement of any of the Fort Martin and Harrison units. *Id.* (Case No. 20-0666, resp. to CAG-2.10).

Q. What do you recommend, based on these analyses?

A. Before the Commission approves rate recovery of a major capital spending program such as a MIP, the Commission should have the benefit of a rigorous forward-looking economic analysis of each of the Fort Martin and Harrison units. That analysis should compare the units' projected capacity, energy, and ancillary services revenues, against the unit-level projected costs of fuel, fixed O&M, variable O&M, taxes, and capital costs, and should also consider new and alternative resource options. Mon Power's own data demonstrates negative net revenues in most years going forward: this should be a "red flag" that prompts Mon Power to rigorously evaluate these units by conducting a forward-looking analysis of their future. Such an analysis is particularly important prior to investing capital that could be avoided by the retirement of one or more units. The more capital costs that are approved for these units in the near-term, the more costs will then become "sunk" and therefore, stranded if the units were to retire earlier than currently planned.

Q. Can you give an example of a capital cost that could potentially be avoided by the retirement of a unit?

A. Yes. If the Companies make a future MIP filing, they might seek rate recovery for the future ELG compliance costs, which witness Sendro estimated would cost $139 million, with the majority of those costs at Fort Martin.[44] The recently released final ELG rule imposes "less stringent limitations" for generating units that permanently cease coal

[44] Sendro Direct Testimony, Exhibit DVS-1A.

combustion by 2028.[45] Mon Power should consider this avenue for some or all units, rather than presume that incurring costs to comply with ELG limitations, necessary for operation past 2028, is the best option for ratepayers.

Q. Would this economic evaluation be consistent with how Mon Power evaluates the remaining terms of its PURPA contracts?

A. Yes. Mon Power conducts periodic buyout or buydown reviews of PURPA projects. Specifically, Mon Power conducts economic analyses to review the projected financial net position, on an NPV basis, of the remaining term of the agreement.[46] Fort Martin and Harrison are large assets that cost ratepayers substantially; they should not be insulated from a similar type of scrutiny.

Q. Please briefly summarize your recommendation for an economic evaluation.

A. Given the poor economic outlook for the Fort Martin and Harrison units, the Companies' customers might benefit if, instead of incurring additional capital expenditures, Mon Power retired one or more of these generating units. To enable the Commission to evaluate the reasonableness of a future MIP proposal, the Commission should direct the Companies that any future MIP filing involving the Fort Martin and Harrison units should be accompanied by a rigorous, forward-looking economic analysis that evaluates the net present value (NPV) of alternative retirement dates for each unit.

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[45] U.S. EPA, *Steam Electric Reconsideration Rule*, 85 Fed. Reg. 64650, 64709 (Oct. 13, 2020) ("Today's final rule would subcategorize LUEGUs and EGUs permanently ceasing coal combustion by 2028, subjecting those subcategories to less stringent limitations.").

[46] Case No. 20-0665, Reeping Direct Testimony at page 6.

Q. Given the poor economic outlook for these units, should the Companies be granted rate recovery for the requested $5 million surcharge in 2021?

A. No. This surcharge is based, in part, on capital expenditures that the Companies incurred, or planned over the 2018-21 timeframe. The Companies have not shown that these $5 million are just, reasonable, and based on prudent investments that are used and useful to the customers. The Companies have not done an economic evaluation to justify these investments relative to other options, such as retiring any of the units. Instead, the Companies have assumed that the plants will continue to operate (at least into the mid-2030s) and that environmental compliance investments should be made, no matter the cost. On this record, where the available evidence shows that the Fort Martin and Harrison plants have and will have negative net revenues for each of the years 2019-2024 (as shown in Figure 1), the Companies have not shown that these expenditures are reasonable.

This surcharge should also not be approved because doing so would be premature. I anticipate that the Companies might propose a future MIP that seeks recovery of ELG expenditures and post-2021 CSAPR and MATS costs. To avoid piecemeal consideration of these costs, the 2018-21 costs should be evaluated as a part of that larger spending program.

IV. FORT MARTIN AND HARRISON HAVE PRODUCED LOSSES IN RECENT MONTHS.

Q. Did you also analyze the monthly performance of Fort Martin and Harrison plants for the ENEC review period?

A. Yes. I analyzed the monthly variable costs and revenues for Fort Martin and Harrison for July 2018 through June 2020. I calculated the monthly "net energy margin," which represents the energy and ancillary services revenue minus the variable operating costs (including variable O&M and fuel). This measure is analogous to the net revenue concept in the previous section but fixed costs (capital, fixed O&M, taxes) and capacity revenues are not included. Therefore, this concept shows whether the units are making money when they are operating and selling energy into the market. If their variable costs are higher than their revenues (i.e. the net energy margin is negative), then ratepayers would have been better off purchasing energy from the PJM wholesale market instead of paying for the plants to operate.

Figure 5 below shows the net energy margin for Fort Martin and Harrison for each month of the ENEC review period. This shows that the plants have mostly been operating at energy losses since December 2019. The losses during months with negative energy margins during the review period, for both plants combined, totaled [redacted].[47] [[[redacted]]] are attributed to the Fort Martin plant, compared to Harrison.

[47] Confidential Exhibit TC-12 (Case No. 20-0665-E-ENEC, "CAG-1.14 Attachment A CONFIDENTIAL" for fuel cost; "CAG-1.14 Attachment C CONFIDENTIAL" for energy and ancillary services revenue; "CAG-1.14 Attachment D CONFIDENTIAL" for variable O&M).

Figure 5: Net Energy Margin of Fort Martin and Harrison by Plant (Energy Revenue minus Variable Costs, $mil) (Confidential)[48]**[[**

[redacted]

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Q. During the review period, how did Mon Power typically commit the Harrison and Fort Martin units into the PJM wholesale market?

A. Mon Power "self-scheduled" the Harrison and Fort Martin units most of the time. When a generating unit is self-scheduled in PJM, the unit operator designates the unit as "must run," which ensures that the unit will operate at least at its "economic minimum."[49] PJM defines the economic minimum as the lowest MW output level a unit can achieve while being economically dispatched.[50] The unit then operates at this economic minimum for that

[48] *Id.*
[49] PJM Manual 11: Energy & Ancillary Services Market Operations, Section 2: Overview of the PJM Energy Markets, p. 25. Available at: https://www.pjm.com/~/media/documents/manuals/m11.ashx.
[50] *See* PJM Glossary, https://www.pjm.com/Glossary.aspx. For coal-fired generating units, the economic minimum is often between 1/3 or 1/2 of the unit's total capacity. However, the unit owner has discretion to adjust the economic minimum higher, [[redacted]

day, but PJM can dispatch the unit to run at a higher level if it is economic to do so. The other option for available units is economic commitment, whereby PJM decides whether to turn on the unit, and then dispatches the unit's level on an economic basis throughout the day. In both cases, if the unit is committed, PJM dispatches based on merit. However, if the unit owner self-schedules, a unit will operate that might not have been operating on a given day if PJM had made an economic commitment decision.

For the review period, I calculated that the units were self-scheduled on average [[[redacted]]] of all available hours, depending on the unit—shown below in Table 5.[51] This means that Mon Power [[[redacted]]] decided whether the units would operate, rather than allow the market to make that decision based on merit.

[redacted]]

[51] *See* Case No. 20-0665, resp. to SC-1.3 & "SC-1.3 Attachment A CONFIDENTIAL" spreadsheet). Data excludes hours where the units were unavailable.

Table 5: Self-Scheduling of Fort Martin and Harrison, Percentage of Available Hours (Confidential)[52][[

[redacted]

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Q. Has self-scheduling coincided with substantial losses at the units in recent months?

A. Yes. Since December 2019, the units have been self-scheduled in most hours, and have also produced substantial monthly losses. Mon Power is [[[redacted]]].[53] This indicates that they are planning on operating the units [[[redacted]]].

Mon Power should consider committing the units on an economic basis. Notably, in [[[redacted]]]. This [[[redacted]]] at the plant in 2020—as shown in Figure 5 above—suggesting that economic commitment could provide savings to the Companies' customers.

[52] *Id.*

[53] Confidential Exhibit TC-13 (resp. to CAG-1.15 & "CAG-1.15 Attachment A CONFIDENTIAL" spreadsheet). [[redacted]].

Q. Has Mon Power conducted studies to compare the units' economic performance when self-scheduling, versus economic commitment?

A. Yes. Mon Power has quantified the net energy revenues during self-scheduling and economic commitment.[54] [[[redacted]]].[55]

Q. What reasons has Mon Power given for why the units are not always committed economically?

A. Mon Power identified some operational reasons for self-scheduling the units.[56] One reason was that coal contracts have a minimum coal take requirement and the units were self-scheduled to ensure that Mon Power met those contractual requirements.

Q. Have any of these conditions changed recently?

A. Yes. In June 2020, Mon Power negotiated a reduction in the coal purchase requirements for 2020 and 2021.[57] However, the direct impact of these coal supply obligations on Mon Power's commitment practices remains unclear.

Q. What do you recommend given your analysis of the ENEC case?

A. First, Mon Power's commitment practice raises concerns because they are self-scheduling units and generating losses in recent months. Mon Power also appears to be planning on [[[redacted]]]. It appears that Mon Power's self-

[54] Confidential Exhibit TC-14 (Case No. 20-0665, resp. to SC-1.7 & SC-1.7 Attachment A CONFIDENTIAL).
[55] *Id.*
[56] Exhibit TC-15 (Case No. 20-0665, resp. to EUG-1.4).
[57] Case No. 20-0665, Liang-Nicol Direct at 4.

scheduling practice is driven, in part, by the minimum take obligations under its supply coal contract. The Commission should direct that, as part of its initial filing in the next ENEC case, Mon Power report back on its continuing efforts to reduce coal supply obligations over the 2020-21 review period, and explain how those obligations influence Mon Power's commitment decisions (e.g., the effect on bid prices into PJM). Mon Power should also be directed to report back on its efforts to improve its commitment practices and methodology in future ENEC cases, including a clear justification for self-scheduling the units during periods of low power prices.

Second, in future ENEC cases the Companies should provide a four- or five-year forecast of the generating units' costs as a standard part of their filing. The reasonableness of the fuel expenses collected through the ENEC is informed, in part, by Mon Power's management and operation of its generation fleet, including capital and O&M costs. This is particularly important for capital projects, which are more easily evaluated over a longer timeframe than one year. The ENEC process would be better served if the Companies provided a four- or five-year look at these cost streams, rather than a one-year projection.

V. CONCLUSION

Q. Does this complete your testimony at this time?

A. Yes.

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

Exhibit TC-1

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PROFESSIONAL EXPERIENCE

Applied Economics Clinic, Arlington, MA. Senior Researcher, June 2017 – Present.

Provides technical expertise on electric utility regulation, energy markets, and energy policy. Clients are primarily public service organizations working on topics related to the environment, consumer rights, the energy sector, and community equity.

Synapse Energy Economics Inc., Cambridge, MA. Senior Associate, July 2014 – June 2017, Associate, July 2011 – July 2014.

Provided expert testimony and reports on energy system planning, coal plant economics and economic impacts. Performed benefit-cost analyses and research on energy and environmental issues.

Ideas42, Boston, MA. Senior Associate, 2010 – 2011.

Organized studies analyzing behavior of consumers regarding finances, working with top researchers in behavioral economics. Managed studies of mortgage default mitigation and case studies of financial innovations in developing countries.

Economic Development Research Group Inc., Boston, MA. Research Analyst, Economic Consultant, 2005 – 2010.

Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for transportation and renewable energy projects, including support for Federal stimulus applications. Developed a unique web-tool for the National Academy of Sciences on linkages between economic development and transportation.

Harmon Law Offices, LLC., Newton, MA. Billing Coordinator, Accounting Liaison, 2002 – 2005.

Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable. Projected legal fees and costs.

Massachusetts Department of Public Health, Boston, MA. Data Analyst (contract), 2002.

Designed statistical programs using SAS based on data from health-related surveys. Extrapolated trends in health awareness and developed benchmarks for performance of clinics for a statewide assessment.

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Tufts University, Medford, MA

Master of Arts in Economics, 2007

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Resume dated October 2020

Exhibit TC-2

**THE SIERRA CLUB'S
SECOND REQUEST FOR INFORMATION
MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY
Case No. 20-0665-E-ENEC**

The following response to Question 9 of the Second Request for Information of the Sierra Club has been prepared under the supervision of the person identified below.

Name:	Cecilia Liang-Nicol
Title:	Manager, Generation Commercial Ops
Company:	FirstEnergy Service Company
Date:	

QUESTION NO. 9

For the Fort Martin and Harrison units, have the Companies conducted any analyses of the economic viability, prudence, and/or net present value revenue requirements for customers of continuing to operate the units?

(a) If not, please explain why not.

(b) If so, please identify the date and nature of each analysis.

(c) Please provide all reports or other documentation of the results of each analysis listed in response to subpart (b), and any supporting calculations, data, documents, modeling input and output files, and workpapers associated with each such analysis.

RESPONSE:

The upcoming IRP to be filed in December predicts under current regulation that the plants will operate through the 15-year IRP forecast period.

WEST VIRGINIA CITIZEN ACTION GROUP AND SOLAR UNITED NEIGHBORS' SECOND REQUEST FOR INFORMATION MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY Case No. 20-0666-E-4435T

The following response to Question 11 of the Third Request for Information of the West Virginia Citizen Action Group and Solar United Neighbors has been prepared under the supervision of the person identified below.

Name:	Mark Valach
Title:	Director Fuels and RTO Services
Company:	FirstEnergy Service Company
Date:	November 6, 2020

QUESTION NO. 11

Refer to your response to EUG-2.5, which states that "[u]nder the assumption the Companies' MIP is approved for recovery of associated costs, the upcoming IRP to be filed in December predicts under current regulation that the plants will operate through the 15-year IRP forecast period."

a. Please identify the anticipated retirement date of each of the Mon Power coal units.

b. Please provide a copy of the current draft of the IRP referenced in this response.

c. Please provide any studies, analyses, or discussion explaining the Companies' prediction that each of the Mon Power coal unit "will operate through the 15-year IRP forecast period."

   i. If the Companies have any economic analyses supporting this prediction, please provide the results of such analyses. Please also provide, in machine-readable format with formulas intact, any underlying modeling files or workpapers.

RESPONSE:

a. There is no specific retirement date established for each of the Mon Power coal units

b. The IRP has undergone several revisions and continues to be revised. Input from FE business units regarding the IRP are frequently provided and evaluated. The value of a specific draft is limited due to the frequency of the revisions. Objection is made to providing draft versions, but the final copy will be provided to the WV PSC by 12/31/2020.

c. The predictions of coal unit operation are based on many inputs that are still being refined, with final analysis to be included in the IRP by 12/31/2020.

THE WEST VIRGINIA ENERGY USERS GROUP'S
FIRST REQUEST FOR INFORMATION
MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY
Case No. 20-0666-E-4435T

QUESTION NO. 3

Please provide copies of any retirement studies performed by, or at the request of, Mon Power, Potomac Edison, or FirstEnergy that examined the economics of retiring any of the Companies' Fort Martin and Harrison coal units performed in the past 3 years.

RESPONSE:

There are no retirement studies that have been performed in the past 3 years.

WEST VIRGINIA CITIZEN ACTION GROUP AND SOLAR UNITED NEIGHBORS' SECOND REQUEST FOR INFORMATION
MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY
Case No. 20-0666-E-4435T

The following response to Question 10 of the Third Request for Information of the West Virginia Citizen Action Group and Solar United Neighbors has been prepared under the supervision of the person identified below.

Name:	Mark Valach
Title:	Director Fuels and RTO Services
Company:	FirstEnergy Service Company
Date:	November 6, 2020

QUESTION NO. 10

Refer to your response to EUG-1.3, which states that no retirement studies have been performed in the past three years. For each of Mon Power's coal units, please state when a retirement study was most recently performed.

RESPONSE:

No retirement studies have been performed for each on the Mon Power's coal units.

WEST VIRGINIA CITIZEN ACTION GROUP AND SOLAR UNITED NEIGHBORS' FIRST REQUEST FOR INFORMATION
MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY
Case No. 20-0666-E-4435T

QUESTION NO. 12

Refer to Exhibit DVS-1. Has Mon Power, Potomac Edison, FirstEnergy Service Company, or any other FirstEnergy Corp. corporate affiliate evaluated whether retirement of any of the Mon Power coal units would be a lower-cost option for ratepayers than incurring the capital expenditures identified in Exhibit DVS-1?

a. If yes, please provide the results of such evaluation. Please also produce, in machine-readable electronic format with formulas intact, all modeling files, including input and output files, and workpapers created, used, or relied on in preparing such evaluation.

RESPONSE:

The cost recovery in this case is for MATS and CSAPR II compliance, which has already been installed, so clearly that small rate increment is better than any retirement with the loss of generation, capacity and energy revenues which are a direct benefit to customers.

WEST VIRGINIA CITIZEN ACTION GROUP AND SOLAR UNITED NEIGHBORS' SECOND REQUEST FOR INFORMATION
MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY
Case No. 20-0666-E-4435T

The following response to Question 6 of the Third Request for Information of the West Virginia Citizen Action Group and Solar United Neighbors has been prepared under the supervision of the person identified below.

Name:	Mark Valach
Title:	Director Fuels and RTO Interface Services
Company:	FirstEnergy Service Company
Date:	November 6, 2020

QUESTION NO. 6

Refer to your response to CAG-1.12. Please confirm that neither Mon Power, Potomac Edison, FirstEnergy Service Company, nor any other FirstEnergy Corp. corporate affiliate have evaluated whether retirement of any of the Mon Power coal units would be a lower-cost option for ratepayers than incurring the capital expenditures identified in Exhibit DVS-1 and not yet incurred.

a. If not confirmed, please correct/supplement your response to CAG-1.12 by identifying such evaluation and providing the information requested in 1.12(a).

RESPONSE:

Confirmed, no retirement analysis of any of the Mon Power coal units has been conducted.

WEST VIRGINIA CITIZEN ACTION GROUP AND SOLAR UNITED NEIGHBORS' FIRST REQUEST FOR INFORMATION
MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY
Case No. 20-0666-E-4435T

QUESTION NO. 11

Refer to Exhibit DVS-1.

a. Please identify the actual or estimated start date for each of the projects listed in this exhibit.

b. For each project listed in this exhibit, please state whether the Companies have performed an internal rate of return ("IRR"), present value ratio ("PVR"), or other economic analysis of the project.

   i. If the Company has concluded that an IRR or PVR analysis is not required for a specific project, please explain why not.

   ii. For each project that does have an IRR, PVR, or other economic analysis, please provide the results of the analysis, and produce, in machine-readable electronic format with formulas intact, any workpapers created, used, or relied on in performing the analysis.

c. Please identify any projects listed in this exhibit that would improve the heat rates of, or reduce forced outages at, at Mon Power's coal units. For each project identified, please explain how such project would improve the coal unit's heat rate or forced outage rate, and produce any supporting documentation.

d. Please identify any projects listed in this exhibit that would reduce O&M costs for Mon Power's coal units. For each project identified, please explain how such project would reduce O&M costs, and produce any supporting documentation.

RESPONSE:

a. For the projects listed in Exhibit DVS-1 (other then the ELG projects), the installation date will be the same year as the in-service date. The ELG projects will start engineering in 2021 with the completion dates noted in the exhibit as the in-service dates.

b. Mon Power previously installed the technologies to comply with the current MATS and CSAPR II and needs the additional projects in order to remain in compliance with these rules and limits. Therefore, an IRR or PVR analysis was not performed on the projects listed.

c. N/A.

d. N/A.

WEST VIRGINIA CITIZEN ACTION GROUP AND SOLAR UNITED NEIGHBORS'
FIRST REQUEST FOR INFORMATION
MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY
Case No. 20-0666-E-4435T

QUESTION NO. 15

Refer to your response to the preceding discovery request (CAG/SUN-1.14), which asked for the Companies' most recent projection of several metrics. If the Companies' projection of these metric would change if the proposed MIP is approved and implemented, please identify those metrics and provide the Companies' projection assuming implementation of the MIP.

RESPONSE:

There are no anticipated revisions to the metrics if the MIP is approved and implemented.

i. If the Company has concluded that an IRR or PVR analysis is not required for a specific project, please explain why not.
ii. For each project that does have an IRR, PVR, or other economic analysis, please provide the results of the analysis, and produce, in machine-readable electronic format with formulas intact, any workpapers created, used, or relied on in performing the analysis.

c. Please identify any projects listed in this exhibit that would improve the heat rates of, or reduce forced outages at, at Mon Power's coal units. For each project identified, please explain how such project would improve the coal unit's heat rate or forced outage rate, and produce any supporting documentation.
d. Please identify any projects listed in this exhibit that would reduce O&M costs for Mon Power's coal units. For each project identified, please explain how such project would reduce O&M costs, and produce any supporting documentation.

12. Refer to Exhibit DVS-1. Has Mon Power, Potomac Edison, FirstEnergy Service Company, or any other FirstEnergy Corp. corporate affiliate evaluated whether retirement of any of the Mon Power coal units would be a lower-cost option for ratepayers than incurring the capital expenditures identified in Exhibit DVS-1?
    a. If yes, please provide the results of such evaluation. Please also produce, in machine-readable electronic format with formulas intact, all modeling files, including input and output files, and workpapers created, used, or relied on in preparing such evaluation.

13. For each of the years 2014-2019 and 2020 (through August 31, 2020), and each of Mon Power's coal-fired generating units, please identify the:
    a. Net generation
    b. Unforced capacity (UCAP)
    c. Equivalent availability factor
    d. Equivalent planned outage factor
    e. Heat rate
    f. Equivalent forced outage rate
    g. Equivalent forced outage rate – demand (EFORd)
    h. Fixed O&M cost
    i. Non-fuel variable O&M cost
    j. Fuel cost (both the total cost, and the cost in dollars per MMbtu)
    k. Fuel usage (MMBtu) by type
    l. Capital cost (Please provide unit-level data wherever available, and please specify any capital costs attributable to common areas or to a Mon Power plant as a whole.)
    m. Energy market revenue
    n. Capacity revenue
    o. Ancillary services revenue

14. For each of the years 2020-2025, and each of Mon Power's coal-fired generating units, please provide the Companies' most recent projection of:

a. Net generation
b. Unforced capacity (UCAP)
c. Equivalent availability factor
d. Equivalent planned outage factor
e. Heat rate
f. Equivalent forced outage rate
g. Equivalent forced outage rate – demand (EFORd)
h. Fixed O&M cost
i. Non-fuel variable O&M cost
j. Fuel cost (both the total cost, and the cost in dollars per MMbtu)
k. Fuel usage (MMBtu) by type
l. Capital cost (Please provide unit-level data wherever available, and please specify any capital costs that attributable to common areas or to a Mon Power plant as a whole.)
m. Energy market revenue
n. Capacity revenue
o. Ancillary services revenue

15. Refer to your response to the preceding discovery request (CAG/SUN-1.14), which asked for the Companies' most recent projection of several metrics. If the Companies' projection of these metric would change if the proposed MIP is approved and implemented, please identify those metrics and provide the Companies' projection assuming implementation of the MIP.

16. For each of Mon Power's coal units:
    a. Please provide the following information as of December 31 for each of the years 2014 through 2019 by unit:
        i. Gross plant balance
        ii. Accumulated depreciation balance
        iii. Net plant balance
        iv. Net salvage (or negative net salvage)
        v. The identification and quantification of any other category of expense collected through depreciation expense (e.g. asset retirement obligations, remediation accounts, etc.).
        vi. Estimated end-of-useful life date for purposes of setting a depreciation schedule.
        vii. The then-applicable annual depreciation expense attributable to the generating unit.
        viii. Rate of return (specify whether pre-tax or post-tax)
        ix. Equity return
        x. Interest payments
        xi. Taxes
        xii. Any other category of costs that factored into the calculation of the unit's revenue requirement.

WEST VIRGINIA CITIZEN ACTION GROUP AND SOLAR UNITED NEIGHBORS'
SECOND REQUEST FOR INFORMATION
MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY
Case No. 20-0666-E-4435T

The following response to Question 3 of the Third Request for Information of the West Virginia Citizen Action Group and Solar United Neighbors has been prepared under the supervision of the person identified below.

Name:	Ray Valdes
Title:	Director, Rates & Regulatory Affairs
Company:	FirstEnergy Service Company
Date:	November 6, 2020

QUESTION NO. 3

Refer to your responses to CAG-1.4(b) and 1.4(d). Please confirm that the Companies have no estimate, projection, or calculation of the amount of the MIP Surcharge for any year past 2021. If not confirmed, please provide any projections, estimations, or calculations for 2022 or later years. Please also provide any supporting workpapers.

RESPONSE:

Confirmed. However, future surcharge rates can be estimated by utilizing the formulas contained within the workpapers provided in response to CAG-1.3.

THE SIERRA CLUB'S
FIRST REQUEST FOR INFORMATION
MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY
Case No. 20-0665-E-ENEC

QUESTION NO. 12

What portion of the Company's load is served by energy purchased from the PJM Energy market and what portion is served by energy generated by Company-owned generators?

RESPONSE:

The Company purchases all load from the Day-ahead and Real-time PJM markets and sells all generation into the Day-ahead and Real-time markets. Generation is not self-scheduled to the load.

CONFIDENTIAL EXHIBIT TC-7

Case No. 20-0666, CAG-1.13 CONFIDENTIAL 10.21 and CAG-1.14 CONFIDENTIAL 10.21

Redacted

Exhibit TC-8

WEST VIRGINIA CITIZEN ACTION GROUP AND SOLAR UNITED NEIGHBORS' FIRST REQUEST FOR INFORMATION
MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY
Case No. 20-0666-E-4435T

QUESTION NO. 16

For each of Mon Power's coal units:

a. Please provide the following information as of December 31 for each of the years 2014 through 2019 by unit:

   i. Gross plant balance

   ii. Accumulated depreciation balance

   iii. Net plant balance

   iv. Net salvage (or negative net salvage)

   v. The identification and quantification of any other category of expense collected through depreciation expense (e.g. asset retirement obligations, remediation accounts, etc.).

   vi. Estimated end-of-useful life date for purposes of setting a depreciation schedule.

   vii. The then-applicable annual depreciation expense attributable to the generating unit.

   viii. Rate of return (specify whether pre-tax or post-tax)

   ix. Equity return

   x. Interest payments

   xi. Taxes

   xii. Any other category of costs that factored into the calculation of the unit's revenue requirement.

b. For each of the years 2014-2019, please identify how common area or plant-wide costs at both Harrison and Fort Martin were allocated (i.e., the percentage assigned to each unit) in calculating the revenue requirement. If these allocations changed over time, please specify that in your response.

Note: if the Companies do not have unit-level information for a particular cost category, please provide the most disaggregated data available

Note: Please provide the requested cost information in machine-readable electronic format, with formulas intact, along with supporting workpapers.

RESPONSE:

a. Please refer to CAG-1.16 Attachment A. Regarding item (vi), the existing depreciation rates are provided in Exhibits RV-2 through RV-8. Items (viii) through (xii) are not calculated on the requested basis.

b. Harrison and Fort Martin utilize a common equipment asset designation for equipment that is not coal unit specific. Costs related to common equipment are not allocated to coal units but held under the common plant designation. Revenue requirements are not calculated on the requested basis.

CAG-1.16 Attachment A

Ft. Martin Common

	Gross Plant Balance	Accumulated Depreciation Balance	Net Plant Balance	Depreciation Expense	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss
12/31/2014	$ 145,406,914.40	$ 71,396,870.15	$ 74,010,044.25	$ 2,405,426.78					
12/31/2015	$ 155,807,271.11	$ 73,913,606.05	$ 81,893,665.06	$ 2,512,455.18	$ (50,366.42)	$ (3,299.24)			
12/31/2016	$ 160,657,443.44	$ 75,408,211.83	$ 85,249,231.61	$ 2,655,519.60	$ (1,193,456.34)	$ (31,495.03)		$ 6,090.91	
12/31/2017	$ 162,080,494.14	$ 77,086,506.73	$ 84,993,987.41	$ 2,723,365.01	$ (1,046,141.31)				
12/31/2018	$ 163,774,890.02	$ 79,889,054.46	$ 83,885,835.56	$ 2,775,554.76				$ (30,942.73)	
12/31/2019	$ 162,179,053.25	$ 74,572,861.95	$ 87,606,191.30	$ 2,745,957.07	$ (7,915,041.21)	$ (205,033.39)			

Part V.	Year	Depreciation Expense	Transfers and Adjustments
MP-WV asb Ft Martin C	2014	$ 57,946.56	
MP-WV asb Ft Martin C	2015	$ 57,946.61	
MP-WV asb Ft Martin C	2016	$ 57,946.67	
MP-WV ARO Ft Martin C	2017	$ 57,946.63	$ (162,724.81)
MP-WV asb Ft Martin C	2017	$ 57,946.63	$ 162,724.81
MP-WV asb Ft Martin C	2018	$ 57,935.74	
MP-WV asb Ft Martin C	2019	$ 57,924.95	

Ft. Martin Unit 1

	Gross Plant Balance	Accumulated Depreciation Balance	Net Plant Balance	Depreciation Expense	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss
12/31/2014	$ 303,928,624.96	$ 131,604,522.15	$ 172,324,102.81	$ 4,926,196.80	$ (95,280.58)				
12/31/2015	$ 277,501,690.63	$ 107,288,572.19	$ 170,213,118.44	$ 5,160,330.43	$ (29,480,711.92)	$ (8,105.40)			
12/31/2016	$ 280,091,334.15	$ 112,170,379.53	$ 167,920,954.62	$ 5,090,750.26	$ (221,479.61)				
12/31/2017	$ 325,148,206.04	$ 117,155,203.26	$ 207,993,002.78	$ 5,182,275.48	$ (209,988.26)	$ -			
12/31/2018	$ 309,532,109.70	$ 104,664,073.86	$ 204,868,035.84	$ 5,695,166.10	$ (17,011,187.25)	$ (1,187,644.51)			
12/31/2019	$ 291,158,787.32	$ 85,520,464.41	$ 205,638,322.91	$ 5,521,523.70	$ (21,982,462.22)	$ (2,695,208.00)			

Part V.	Year	Depreciation Expense
MP-WV asb Ft Martn U1	2014	$ 12,536.64
MP-WV asb Ft Martn U1	2015	$ 12,536.64
MP-WV asb Ft Martn U1	2016	$ 12,536.64
MP-WV asb Ft Martn U1	2017	$ 12,536.64
MP-WV asb Ft Martn U1	2018	$ 12,536.64
MP-WV asb Ft Martn U1	2019	$ 12,536.64

Ft. Martin Unit 2

	Gross Plant Balance	Accumulated Depreciation Balance	Net Plant Balance	Depreciation Expense	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss
12/31/2014	$ 201,390,766.41	$ 117,932,083.18	$ 83,458,683.23	$ 2,543,467.33	$ (475,418.77)				
12/31/2015	$ 202,415,200.33	$ 120,350,402.18	$ 82,064,798.15	$ 2,551,321.26	$ (135,913.56)				
12/31/2016	$ 262,969,746.37	$ 120,822,275.29	$ 142,147,471.08	$ 3,116,048.69	$ (2,497,644.08)	$ (149,442.82)			
12/31/2017	$ 254,184,318.15	$ 112,847,836.09	$ 141,336,482.06	$ 3,572,036.81	$ (10,979,375.17)	$ (570,011.51)			
12/31/2018	$ 257,427,906.39	$ 116,055,727.60	$ 141,372,178.79	$ 3,609,422.65	$ (404,442.65)				
12/31/2019	$ 274,990,565.14	$ 107,282,221.35	$ 167,708,343.79	$ 3,536,643.90	$ (10,842,909.80)	$ (1,470,151.08)			

Part V.	Year	Depreciation Expense
MP-WV asb Ft Martn U2	2014	$ 2,911.14
MP-WV asb Ft Martn U2	2015	$ 2,911.12
MP-WV asb Ft Martn U2	2016	$ 2,911.09
MP-WV asb Ft Martn U2	2017	$ 2,911.10
MP-WV asb Ft Martn U2	2018	$ 2,911.12
MP-WV asb Ft Martn U2	2019	$ 2,911.07

Ft. Martin data excludes securitized scrubbers
Data excludes step-ups

Exhibit TC-8

CAG-1.16 Attachment A

Harrison Common

Date / Item	Year	Gross Plant Balance	Accumulated Depreciation Balance	Net Plant Balance	Depreciation Expense	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss
12/31/2014		$ 183,615,928.63	$ 24,598,166.00	$ 159,017,762.63	$ 3,396,879.87	$ (143,447.17)			$ 920.44	
12/31/2015		$ 196,624,866.63	$ 27,643,346.21	$ 168,981,520.42	$ 3,392,360.41	$ (342,047.26)			$ 78.41	
12/31/2016		$ 203,066,717.05	$ 31,391,096.77	$ 171,675,620.28	$ 4,013,474.06	$ (257,502.47)	$ (3,831.39)		$ 821.25	
12/31/2017		$ 196,109,644.86	$ 34,187,139.39	$ 161,922,505.47	$ 4,123,566.88	$ (1,322,103.72)	$ (209.51)			
12/31/2018		$ 196,248,120.30	$ 38,189,751.17	$ 158,058,369.13	$ 4,336,177.78	$ (319,124.33)	$ (10,314.11)		$ 1,083.63	
12/31/2019		$ 205,184,549.24	$ 40,039,652.48	$ 165,144,896.76	$ 4,396,509.40	$ (2,541,397.09)				
Part V.										
MP-WV ARO Harrison Commo	2014				$ (5,211.12)					
FERC Adjustment, not in 403000	2014				$ 5,211.12				$ (5,211.12)	
MP-WV ARO Harrison Commo	2015				$ (5,211.12)					
FERC Adjustment, not in 403000	2015				$ 5,211.12					$ (5,211.12)
MP-WV ARO Harrison Commo	2016				$ (5,211.12)					
FERC Adjustment, not in 403000	2016				$ 5,211.12					$ (5,211.12)
MP-WV ARO Harrison Commo	2017				$ (5,211.12)					
FERC Adjustment, not in 403000	2017				$ 5,211.12				$ (5,211.12)	
MP-WV ARO Harrison Commo	2018				$ (5,211.12)					
MP-WV ARO Harrison Commo	2019				$ (5,211.12)					

Harrison Unit 1

Date / Item	Year	Gross Plant Balance	Accumulated Depreciation Balance	Net Plant Balance	Depreciation Expense	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss
12/31/2014		$ 844,566,490.22	$ 529,864,105.13	$ 314,702,385.09	$ 11,638,842.59	$ (5,905,311.16)				
12/31/2015		$ 880,342,644.46	$ 525,451,070.08	$ 354,891,574.38	$ 11,935,139.70	$ (16,182,664.98)	$ (39,863.94)			
12/31/2016		$ 871,361,023.46	$ 520,818,090.73	$ 350,542,932.73	$ 12,705,206.90	$ (17,203,949.16)	$ (8,590.56)			
12/31/2017		$ 868,269,001.58	$ 520,322,844.29	$ 347,946,157.29	$ 12,782,230.68	$ (13,046,079.03)	$ (105,755.24)			
12/31/2018		$ 872,570,362.26	$ 513,108,409.59	$ 359,461,952.67	$ 12,215,941.86	$ (18,708,405.15)	$ (596,323.88)			
12/31/2019		$ 871,015,759.19	$ 518,159,170.81	$ 352,856,588.38	$ 12,877,166.26	$ (7,070,726.33)	$ (630,035.78)			
Part V.										
MP-WV ARO Harrison U 1	2014				$ (125,645.11)					
FERC Adjustment, not in 403	2014				$ 125,645.11				$ (125,645.11)	
MP-WV ARO Harrison U 1	2015				$ (125,645.21)					
FERC Adjustment, not in 403	2015				$ 125,645.21					$ (125,645.21)
MP-WV ARO Harrison U 1	2016				$ (125,645.25)					
FERC Adjustment, not in 403	2016				$ 125,645.25					$ (125,645.25)
MP-WV ARO Harrison U 1	2017				$ (125,645.17)					
FERC Adjustment, not in 403	2017				$ 125,645.17				$ (125,645.17)	
MP-WV ARO Harrison U 1	2018				$ (125,645.20)					
MP-WV ARO Harrison U 1	2019				$ (125,645.20)					

Harrison Unit 2

Date / Item	Year	Gross Plant Balance	Accumulated Depreciation Balance	Net Plant Balance	Depreciation Expense	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss
12/31/2014		$ 276,208,580.77	$ 146,662,946.27	$ 129,545,634.50	$ 3,687,175.41	$ (1,345,896.79)			$ (999.51)	
12/31/2015		$ 275,954,635.98	$ 149,943,704.27	$ 126,010,931.71	$ 3,675,292.18	$ (394,674.65)	$ 1,770.98			
12/31/2016		$ 298,604,008.83	$ 129,011,437.40	$ 169,592,571.43	$ 3,678,330.69	$ (24,604,537.64)	$ (4,429.32)			
12/31/2017		$ 315,307,307.29	$ 117,145,628.17	$ 198,161,679.12	$ 4,200,274.59	$ (11,716,156.69)	$ (4,348,296.06)			
12/31/2018		$ 293,826,539.03	$ 118,157,667.79	$ 175,668,871.24	$ 4,169,425.97	$ (3,015,589.96)	$ (140,165.74)			
12/31/2019		$ 304,656,511.42	$ 112,142,464.86	$ 192,514,046.56	$ 4,150,437.61	$ (9,515,653.58)	$ (648,356.35)			
Part V.										
MP-WV asb Harrison U2	2014				$ (1,630.68)					
MP-WV asb Harrison U2	2015				$ (1,630.68)					
MP-WV asb Harrison U2	2016				$ (1,630.68)					
MP-WV asb Harrison U2	2017				$ (1,630.68)					
MP-WV asb Harrison U2	2018				$ (1,630.68)					
MP-WV asb Harrison U2	2019				$ (1,630.68)					

Harrison Unit 3

Date / Item	Year	Gross Plant Balance	Accumulated Depreciation Balance	Net Plant Balance	Depreciation Expense	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss
12/31/2014		$ 281,365,383.26	$ 150,842,445.58	$ 130,522,937.68	$ 4,112,687.18	$ (2,622,228.64)				
12/31/2015		$ 297,667,402.63	$ 132,751,635.32	$ 164,915,767.31	$ 3,664,832.06	$ (19,896,879.69)	$ (1,860,537.94)			
12/31/2016		$ 289,180,449.76	$ 126,884,522.94	$ 162,295,926.82	$ 4,144,598.37	$ (9,978,705.03)	$ (33,034.65)		$ (1,746.30)	
12/31/2017		$ 291,860,464.11	$ 119,936,659.93	$ 171,923,804.18	$ 4,159,298.93	$ (10,971,823.74)	$ (137,114.00)			
12/31/2018		$ 313,525,295.91	$ 118,966,954.05	$ 194,558,341.86	$ 4,465,598.35	$ (2,122,217.21)	$ (3,316,604.16)		$ 1,742.63	
12/31/2019		$ 314,876,512.44	$ 121,192,475.05	$ 193,684,037.39	$ 4,489,249.32	$ (2,217,647.33)	$ (47,856.17)			
Part V.	2014				$ 1,775.04					
MP-WV asb Harrison U3	2015				$ 1,775.04					
MP-WV asb Harrison U3	2016				$ 1,775.04					
MP-WV asb Harrison U3	2017				$ 1,775.04					
MP-WV asb Harrison U3	2018				$ 1,775.04					
MP-WV asb Harrison U3	2019				$ 1,775.04					

Data excludes step-ups

CAG-1.16 Attachment A

Retirement Work In Progress

FERC Depr Group	Year	Depreciation Expense	Retirements	Cost of Removal	Salvage and Other Credits	Transfers and Adjustments	Impairments and (Gain) / Loss
RWIP, Non-Unitized	2014						$ (1,042,643.94)
RWIP, Non-Unitized	2015			$ 607,738.95			
RWIP, Non-Unitized	2016			$ (4,816,200.29)			
RWIP, Non-Unitized	2017			$ (2,098,863.77)			
RWIP, Non-Unitized	2018			$ 2,112,803.33			
RWIP, Non-Unitized	2019			$ 4,788,726.84			

CONFIDENTIAL EXHIBIT TC-9

Case No. 20-0666, Revised CAG-1.17 & Attachment A CONFIDENTIAL

Redacted

WEST VIRGINIA CITIZEN ACTION GROUP AND SOLAR UNITED NEIGHBORS' THIRD REQUEST FOR INFORMATION
MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY
Case No. 20-0665-E-ENEC

The following response to Question 5 of the Third Request for Information of the West Virginia Citizen Action Group and Solar United Neighbors has been prepared under the supervision of the person identified below.

Name:	Ray Valdes
Title:	Director, Rates & Regulatory Affairs
Company:	FirstEnergy Service Company
Date:	November 6, 2020

QUESTION NO. 5

Please provide the Companies' pre-tax rate of return for each of the years 2014 through 2020, including supporting calculations (including capital structure, return on equity, cost of debt, and federal/state income tax rates).

RESPONSE:

Please see CAG-3.5 Attachment A for the requested information for the review period and the information available for 2020.

Monongahela Power Company
Rate of Return

Notes:
1) Percent To Total and Debt Cost Rate is consolidated information for distribution, transmission, and generation for West Virginia
2) Common Equity Rate represents the earned West Virginia combined distribution, transmission, and generation ROE for the respective period

At December 31, 2017	Percent To Total	Cost Rate	Weighted Cost
Long-Term Debt	51.89%	4.77%	2.48%
Common Equity for Ratemaking	48.11%	9.11%	4.38%
Rate of Return			6.86%

At December 31, 2018	Percent To Total	Cost Rate	Weighted Cost
Long-Term Debt	52.45%	4.64%	2.43%
Common Equity for Ratemaking	47.55%	9.11%	4.33%
Rate of Return			6.76%

At December 31, 2019	Percent To Total	Cost Rate	Weighted Cost
Long-Term Debt	54.70%	4.48%	2.45%
Common Equity for Ratemaking	45.30%	9.20%	4.17%
Rate of Return			6.62%

At March 31, 2020	Percent To Total	Cost Rate	Weighted Cost
Long-Term Debt	54.46%	4.48%	2.44%
Common Equity for Ratemaking	45.54%	8.57%	3.90%
Rate of Return			6.34%

Federal Income Tax Rate =	35.00%	2017
Federal Income Tax Rate =	21.00%	2018-2020
WV State Income Tax Rate =	6.50%	2017-2020

The Potomac Edison Company
Rate of Return

Notes:
1) Percent To Total and Debt Cost Rate is consolidated information for distribution and transmission for the combination of West Virginia, Maryland, and Virginia
2) Common Equity Rate represents the earned West Virginia combined distribution and transmission ROE for the respective period

At December 31, 2017	Percent To Total	Cost Rate	Weighted Cost
Long-Term Debt	48.24%	4.33%	2.09%
Common Equity for Ratemaking	51.76%	9.07%	4.70%
Rate of Return			6.79%

At December 31, 2018	Percent To Total	Cost Rate	Weighted Cost
Long-Term Debt	47.49%	4.33%	2.06%
Common Equity for Ratemaking	52.51%	10.55%	5.54%
Rate of Return			7.60%

At December 31, 2019	Percent To Total	Cost Rate	Weighted Cost
Long-Term Debt	45.54%	4.33%	1.97%
Common Equity for Ratemaking	54.46%	9.79%	5.33%
Rate of Return			7.31%

At March 31, 2020	Percent To Total	Cost Rate	Weighted Cost
Long-Term Debt	45.34%	4.33%	1.96%
Common Equity for Ratemaking	54.66%	4.43%	2.42%
Rate of Return			4.39%

Federal Income Tax Rate =	35.00%	2017
Federal Income Tax Rate =	21.00%	2018-2020
WV State Income Tax Rate =	6.50%	2017-2020

CONFIDENTIAL EXHIBIT TC-11

Case No. 20-0665, resp. to CAG-1.11 & "CAG Data Request 1st set Q11.a backup – CONFIDENTIAL" spreadsheet (excerpt); Case No. 19-0785-E-ENEC, resp. to CAG-1.10 & "CAG Data Request 1st set Q10 Attachment A-2nd request CONFIDENTIAL" spreadsheet (excerpt)

Redacted

CONFIDENTIAL EXHIBIT TC-12

Case No. 20-0665, resp. to CAG-1.14 & CAG-1.14 Attachments A, C, and D CONFIDENTIAL

Redacted

CONFIDENTIAL EXHIBIT TC-13

Case No. 20-0665, resp. to CAG-1.15 & CAG-1.15 Attachment A CONFIDENTIAL

Redacted

CONFIDENTIAL EXHIBIT TC-14

Case No. 20-0665, resp. to SC-1.7 & SC-1.7 Attachment A CONFIDENTIAL

Redacted

THE WEST VIRGINIA ENERGY USERS GROUP'S
FIRST REQUEST FOR INFORMATION
MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY
Case No. 20-0665-E-ENEC

QUESTION NO. 4

For each of the Companies' coal units, please provide a narrative describing any must run constraints that would cause the unit to be dispatched when the day-ahead PJM Interconnection, LLC ("PJM") Locational Marginal Price ("LMP") is less than the incremental cost of the unit. Please include in the narrative the cause of the must run constraint, including any constraints associated with a requirement to burn a minimum amount of coal pursuant to a coal contract.

RESPONSE:

Conditions when units are offered in as “must run”:

- Coal contracts have a minimum coal take requirement. Units are offered as must run to ensure we meet these contractual requirements.
- When units are offered in as “economic” and are brought online by PJM, the offers for the next several days are changed to “must run” to ensure unit stays online. This is an operational requirement to ensure unit reliability.
- Must run status was used to perform environmental testing (SO3 Breem Probe Testing) required by the Department of Environmental Protection.
- Must run one unit:
    - To ensure solid waste processing does not become water bound. Solid waste processing requires burning the liquid in one of the absorbers.
    - Freeze protection for the plant

WEST VIRGINIA CITIZEN ACTION GROUP AND SOLAR UNITED NEIGHBORS' FIRST REQUEST FOR INFORMATION
MONONGAHELA POWER COMPANY AND THE POTOMAC EDISON COMPANY
Case No. 20-0665-E-ENEC

QUESTION NO. 12

Refer to page 4, lines 10-18 of the Liang-Nicol Direct Testimony.

a. Please provide the generation output data used to calculate the 2% decrease referenced on page 4, lines 12-14 of Ms. Liang-Nicol's testimony.

b. Please state whether Ms. Liang-Nicol's reference to the Mon Power units' output on page 4, lines 12-14 includes (i) output from the Bath County plant, and/or (ii) output associated with Mon Power's PURPA projects.

c. Please describe with specificity the outcomes of each of Mon Power's negotiations with a coal supplier to reduce coal burn requirements, including (i) the applicable contract, (ii) the coal purchase requirements (or coal burn requirements) under such contract, (iii) the amount by which the requirements have been reduced, and (iv) the consideration (lump-sum payment, higher purchase price, etc.) provided by Mon Power to secure such reduction.

RESPONSE:

a.

- Ms. Liang-Nicol's testimony referred to a 2% decrease. The 2% decrease is a 2019-2018 comparison for January – May only. The calendar year difference is 1% higher output for 2019 compared to 2018.

- 2019 Mon Power's generation did not decrease with the decrease in LMP due to the specified coal obligation in Mon Power's coal contracts and the nature of the PURPA contracts. The output of the PURPA units is offered into the PJM energy market on a day-ahead basis. While each contract is a must take agreement, meaning the Companies have to take the full output of the PURPA projects during most hours of the year, the Companies do exercise their limited dispatch rights when economic to reduce purchases and thus expense where possible. Revenues received from PJM from the sales of energy and capacity into the PJM markets are used to offset the contract expenses paid to the PURPA projects for the benefit of the Mon Power's customers.

  See CAG-1.12 Attachment A CONFIDENTIAL which contains CONFIDENTIAL information and is being provided pursuant to the terms of the Protective Agreement.

b. (i) Includes output from Bath County plant;
   (ii) Includes output from Mon Power's PURPA projects

c. See CAG-1.12 Attachment B CONFIDENTIAL which contains CONFIDENTIAL information and is being provided pursuant to the terms of the Protective Agreement.

CERTIFICATE OF SERVICE

I hereby certify that on this date I (1) served a copy of the foregoing PUBLIC VERSION of the Direct Testimony of Tyler Comings upon the parties listed below; and (2) served a copy of the CONFIDENTIAL VERSION of the Direct Testimony of Tyler Comings upon the Companies, and those parties that have executed an appropriate protective agreement with the Companies.

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Date: November 16, 2020

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