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Public Service Commission of West Virginia

201 Brooks Street, P.O. Box 812
Charleston, West Virginia 25323

Phone: (304) 340-0300
Fax: (304) 340-0325

April 28, 2023

Karen Buckley, Executive Secretary
Public Service Commission
P.O. Box 812
201 Brooks Street
Charleston, WV 25323

Re: Case No. 21-0339-E-ENEC
Appalachian Power Company and
Wheeling Power Company

Case No. 22-0393-E-ENEC
Appalachian Power Company and
Wheeling Power Company

Dear Ms. Buckley:

Enclosed is the PUBLIC VERSION of the "*Independent Technical Prudency Review of the Actions Affecting the Operations of Amos, Mountaineer, and Mitchell Coal Plants*" in the above-referenced proceedings. A copy has been served upon all parties of record.

Very truly yours,

LUCAS R. HEAD
Staff Attorney
WV State Bar I.D. No. 11146

LRH/jt
Enclosures
S:_Staff_Files\LHead\Cases\2022 Cases\22-0393-E-ENEC, APCo and WPCo\CTC Prudent Report PUBLIC VERSION Cover .docx

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INDEPENDENT TECHNICAL PRUDENCY REVIEW OF THE ACTIONS AFFECTING THE OPERATIONS OF AMOS, MOUNTAINEER, AND MITCHELL COAL PLANTS

CASE NO. 21-0339-E-ENEC

CASE NO. 22-0393-E-ENEC

PUBLIC VERSION

CRITICAL
TECHNOLOGIES
CONSULTING

Independent Technical Prudency Review of the Actions Affecting the Operations of Amos, Mountaineer, and Mitchell Coal Plants Case No. 22-0393-E-ENEC and 21-0339-E-ENEC

Final Report
Public Version

CRITICAL
TECHNOLOGIES
CONSULTING

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1. Purpose of the Prudency Review

The purpose of this review is to conduct on behalf of the PSC Staff (Staff) an independent technical prudency review of the decisions and actions taken (or not taken) by the regulated utilities Appalachian Power Company (APCo) and Wheeling Power Company (WPCo) (jointly the Companies), affecting their coal power plants located in West Virginia owned and operated to meet the requirements of the Commission orders issued during late 2021 and 2022. This review was conducted as independent consultants to Staff so that CTC has been free of any opinions of Staff and developed its own conclusions. As requested by the Commission, CTC will provide expert evaluations and discussions, as to the prudency of the regulated Companies actions and inactions. This document presents the results of the independent review conducted for the PSC Staff.

2. Summary of the Scope of Work

The Scope of Work is defined by the Commission Order issued May 13, 2022 in Case No. 21-0339-E-ENEC, as follows:

> *"The Commission requires Commission Staff to undertake a review of the prudence of Appalachian Power Company (APCo) and Wheeling Power Company (WPCo) (jointly the Companies) Expanded Net Energy Cost (ENEC) including fuel purchasing practices, power plant utilization, bidding strategy to sell generation into the PJM energy market, extent to which generation from the Companies' plants failed to clear the PJM energy market during hours of PJM energy prices in excess of the incremental variable costs of self-generation, and reliance on PJM energy relative to self-supply options. The Commission grants recovery for a portion of revised projected ENEC costs subject to future evaluation of recoveries, costs, prudence, reasonableness and determinations of the reasonableness of inclusion of under-recoveries in future ENEC rates."*

CTC was contracted by Commission Staff to provide services required to conduct and prepare a report on the independent prudency reviews and to provide expert witness services as needed involving the operations and maintenance of the John Amos (Amos), Mountaineer, and Mitchell coal power plants. CTC examined independently the data available in the case and formulated Data Requests to address the issues and comments the Commission presented in its Order in this case and any other services the Staff requests.

A further clarification on the prudency review covered by this report and the order of May 13, 2022 was provided by the Commission in an order on Case No. 22-0393-E-ENEC dated February 3, 2023 in the "Discussion" section of this recent order:

> *"The Commission selected a 69 percent capacity factor over an entire year because we knew that there would be periods of time that the plants would be out of service for planned maintenance and other times for unplanned outages. However, during hours when the plants were capable of running and when the true variable cost of generation was near or below alternative purchased power costs, and when we expected them to run as near to 100 percent as possible. We also took into consideration that to be available during hours when purchased power prices increased above the variable cost of generation, it would be necessary to have the plants ready to ramp up to maximum output in the minimum ramp time possible."*
>
> *"The 69 percent was, therefore, an expected minimum based on the record before us at the time regarding purchased power costs and generation costs. We made it clear that the first step in our future review of the reasonableness of net ENEC costs would be to determine if the Companies had achieved that expectation. Reaching that goal would not, by itself, be dispositive of the question of reasonableness of net ENEC costs if the costs were challenged by competent evidence. However, it would be easier for the Companies to meet their burden of proof regarding reasonableness of costs and prudence of their management of ENEC costs if they achieve the 69 percent annual capacity factor."*
>
> *"On the other hand, if they do not achieve the 69 percent capacity factor, we made it clear that the burden would be on the Companies to demonstrate that their actions that affected net ENEC costs were prudent and that the resulting net ENEC costs were reasonable and should be included in rates."*
>
> *"The actions that would be necessary to demonstrate prudence will include: (1) maintaining adequate economical fuel supplies, (2) keeping plants available for generation the maximum amount of time, (3) maximum reduction, in accordance with good engineering and operating practices, of outage times related to maintenance, repairs, equipment modifications, site modifications, or other reasons, and (4) effectively bidding to clear the PJM energy market considering the possibility of some negative hourly net margins that were necessary to maximize ensuing positive hourly net margins."*

CTC had accomplished this independent prudency review following the above guidelines even though they were issued after the first drafts of this report were issued.

The CTC scope of review included Case No. 21-0339-E-ENEC and Case No. 22-0393-E-ENEC in conducting the prudency evaluation of the procurement practices and bidding strategies used by the Companies involved in the dispatching of the coal power stations including the associated expenses incurred by the Companies. This scenario was very useful since a number of issues which are subject to this independent prudency review inquiry were discussed at the hearings and in testimony under Case No. 22-0393-E-ENEC, which CTC reviewed and has taken into account in this report. This also expedited CTC's reviews and development of data requests, as some of them had been answered by the Companies in this Case No. 22-0393-E-ENEC.

3. Approach to the Assignment

CTC has conducted this assignment as an independent technical consultant to obtain the facts concerning the approach the Companies took, and the actual compliance of the Companies to meet the various instructions and requirements in the various orders issued during 2021 and 2022 by the Commission affecting these coal power plants under the jurisdiction of the Commission.

CTC also examined the Data Requests and responses provided by the Companies in Case No. 22-0393-E-ENEC. Since the majority of these occurred before CTC was contracted, this provided the opportunity for a more thorough review of specific areas important for the development of this report. The timeline of the various cases, testimonies and orders is presented in Appendix A (attached).

CTC reviewed the Data Requests and associated responses provided by the Companies in both cases.

- Additional interrogatories developed by CTC which have been responded to by the Companies.
- CTC is looking in its evaluation of the facts, not only what was known, but also what should have been known based on the testimony provided, the responses to all the Data Requests and the Companies public information.
- CTC has been evaluating the major processes used in the decision making and the actual decisions made by the Companies for the periods covered by the two Cases. CTC has not made any assumptions or conjectures as to what has occurred, but it is only looking at what actually occurred.
- CTC reviewed the actual capacity factors the Companies achieved during the periods (see Table 1 and Figure 1, pages 21 and 22 of this report) just before the site visits and discussions with site personnel were held. CTC did not see evidence of changes in processes or instructions issued by the Companies to its personnel at the sites and in the supporting organizations specifically addressing steps to make the plants competitive enough to bid and be successful by being dispatched

into the PJM market. This would have resulted in achieving better capacity factors than achieved and possibly closer to the capacity factor at or around the 69% established by the Commission.

- Thus, we confirm that the Companies did not modify their customary processes in procuring the fuel and bidding the plants in PJM as also supported by the testimony of Emily Medine which CTC reviewed. In her testimony, Ms. Medine addressed the fuel requirements to meet better capacity factors than achieved or in maintaining the coal plants in-service meeting close to the Commission's established capacity factor. Her rebuttal testimony dated September 23, 2022, indicated:
-

"In my Direct Testimony I identified three areas of imprudence:

> ***(1) the Companies failed to put in place a portfolio of fuel supply agreements consistent with their own Regulated Fuel Procurement Policy and Procedures Manual,***
>
> ***(2) the Companies failed to respond in a timely manner to the significant market events that were occurring in mid-2021, and***
>
> ***(3) the Companies failed to secure performance under the coal supply agreements they had in place. The net result of these failures was both high-cost coal and insufficient coal to operate their plants in a manner that would have yielded significant benefits to their ratepayers — both in terms of the cost of production and the revenues the Companies could have realized by being net sellers of power into a high-priced market."***

Of key importance to our prudency review has been the visits to the coal plant facilities involved and discussions held with plant staff. We should mention that the Field Operations provided excellent cooperation in supporting CTC's activities and responding to CTC's questions and clarifications during and after the site visits.

Fuel Purchasing

Ms. Emily Medine and Mr. Ralph Smith have addressed in detail the fuel purchasing and bidding strategies and have provided testimony on these issues. We concur with their findings and conclusions. CTC discussed with plant personnel at all three sites the technical condition of each site's fuel storage and the frequency of delivery at each site. CTC also looked at the technical condition of barge delivery equipment and coal storage at each site and found them to be well maintained and ready to operate when needed. CTC did not see any reasons why these facilities could not hold 30 to 45 days minimum of coal supply on the ground if needed.

CTC did not see, nor discover significant communications that existed between the site personnel and the fuel purchasing group relative to the Commission's orders except in communicating when deliveries were to be made, just following their existing processes and procedures. Similarly, there appeared to be no communications between the personnel bidding the plants into PJM and the site personnel at each power plant. We found that the fuel procurement and PJM bidding processes appeared to not change to accommodate the Commission's orders in extending the in-service dates to 2040 or beyond for the coal plants, and obtaining higher capacity factors (at 69% or close to that).

It should be noted that Monday morning meetings had been established within a couple of months of CTC site visits and that it included plant personnel, fuel procurement personnel and regulatory personnel in order to manage the coal shortage issues they were facing. One cannot help but speculate that if these weekly or even monthly meeting were implemented on a regular basis over the past few years that this lack of competitive fuel scenario could have been minimized.

Power Plant Utilization

CTC found the power plant facilities in good condition to achieve reasonable availability factors and high-capacity factors. The plant personnel with their contractors have done a reasonable job in maintaining these supercritical coal power plants.

CTC reviewed the power plant capacity factors available from various responses to Data Requests and testimony provided by the Companies, and which were discussed with plant personnel during the site visits. Based on these reviews and discussions,
CTC concluded that there did not seem to have been any specific effort on the part of the Companies to obtain competitive coal supplies for the longer term which would have lowered the variable costs of generation allowing an opportunity for more successful bids at PJM auctions, assuring the coal plants would have higher capacity factors than actually achieved.

CTC also saw an uptake of use of the coal plants during the summer of 2021 which showed the plants to be competitive because the coal used was competitive. It seems the Companies made the decision to burn the coal at hand to lower their coal inventories available from 2020 without consideration to the potential coal scenarios in later 2021, when the Companies acknowledge that they could not obtain bids (spring of 2021) on a competitive basis for coal supplies for their plants in later 2021 and 2022.

In addition, as a result of the fuel purchasing process decisions and non-decisions, insufficient fuel was available to run the plants. It appeared to CTC that the coal plants used this available time to conduct additional and longer maintenance as a way to preserve the lower coal balances.

Given the reliance of the Companies on PJM to source their power for some years and given that their personnel did not appear to change any of their processes, but instead showing preference for PJM power generation rather than self-generation, CTC understands why the capacity factors of the coal plants did not approach the 69% target as established by the Commission. Further, this could have played a significant role in the failure to have the coal available to meet capacity factors higher than what was achieved.

Bidding Strategy to Sell Generation into the PJM Energy Market

Based on the reviews CTC conducted of the various documents provided in the Case, there seemed to be no change in the strategy being used by the Companies in bidding the energy into PJM after receipt of the Orders (August 2, 2021 and October 14, 2021) in Case No. 20-1040-E-CN filed in December 23, 2020. These Orders provided the Certificate of Convenience and Necessity to allow the coal plants to be retrofitted to meet the EPA requirements on CCR and ELG which would allow the power plants to continue in-service operations through 2040 and beyond, with an associated increase in rates included. Little consideration appeared to have been given to the requirements of higher-capacity factors which the Commission established in September 2021. In addition, the Companies did not change their bidding processes into PJM when they found the coal inventories at the various coal units to be low. And, with the high coal prices they found during this period, the Companies realized the plants would not be chosen to be dispatched given their high variable costs. Further, by utilizing adders to their bids into PJM, the Companies' personnel made certain the plants would not be dispatched; otherwise, they could run out of the coal they had left at the plants, which is not a tolerable scenario. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Further information on the coal availability and coal prices were discussed in the testimonies of Emily Medine and Ralph Smith in Case No. 21-0339-E-ENEC and Case No. 22-0393-E-ENEC.

Extent to which generation from the Companies' plants failed to clear the PJM energy market during hours of PJM energy prices in excess of the incremental variable costs of self-generation

The net effect of no significant changes in the processes of procuring the fuel and bidding into PJM has been that the plants were not able to be dispatched by PJM resulting in inconsistent lower capacity factors for the coal units and increased costs to the rate payers. The Capacity Factors for the period of September 2021 through September 2022 are presented in Table 1.

CTC did not discover documentation in its review which indicated that the Companies considered bidding slightly below cost to get dispatched by PJM and increase the capacity factors of these coal plants. Further, due to the supply constraints the Companies faced, it would have been difficult to encourage the higher use of the coal plants.

Our conclusion is that it appears the Companies did not actively pursue any attempts to get the coal plants dispatched and achieve higher capacity factors.

Reliance on PJM Energy Relative to Self-supply options

The processes of fuel procurement and bidding into PJM did not appear to account for the requirements of the Commission to operate the plants at higher capacity factors. It seems that the Companies rely on PJM as the "ultimate supplier of generation" for their systems and do not appear to favor the self- generation options of their coal power plants.

Based on CTC's review of the capacity factors of the coal plants over the past ten years, the Companies have placed an overreliance on the PJM Market and nearly got out of the habit of utilizing their own plants for their generation.

4. Site Visits

The following coal plant sites were visited during the week of October 17, 2022:

- Mitchell
- Mountaineer
- Amos

5. Mitchell Plant Review

The Michell Coal Plant includes two (2) generating units capable of operating independently with common resources:

- Fifty percent (50%) ownership by Wheeling Power (WPCo).
- Fifty percent (50%) ownership by Kentucky Power. This share was sold to Liberty Utilities (Owned by Algonquin Utilities) pending approval by FERC which was recently denied without prejudice, by the FERC. FERC found that the applicant (Kentucky Power) failed to provide adequate information to demonstrate what effect, if any, the transaction would have on transmission rates to the customers.
- Wheeling Power operates and maintains the plant.

Both units are not tied to a common electrical transmission line:

- Unit No. 1 with a net generation capability of 770 megawatts sends power out on a 345 kV transmission line.
- Unit No. 2 with a net generation capability of 790 megawatts sends power out on a 765 kV transmission line.

Current approved staff size is 184 exempt and nonexempt individuals:

- Staff size in 2018 was 250.
- Major outage work is performed by contract labor.
- AEP Service Company provides home office support e.g., environmental, procurement and construction support.

Planned Maintenance Outages:

- Minor outages are on an annual basis and scheduled for two (2) to seven (7) weeks.
- Major outages are scheduled for every three (3) years with durations generally for twelve (12) weeks.

Turbine outages are performed on a partial basis with every major outage.

Primary fuel is a blend of low and high sulfur Appalachian coal:

- Coal storage capacity ranges from 900,000 to 1,000,000 tons.
- Primary source for coal was an adjacent coal mine with delivery by means of a 26-mile conveyor belt.
- Coal procurement is handled by AEP Service Company in Columbus, Ohio.
- AEP Service Company provides home office support e.g., environmental, procurement, and construction.
- Coal is purchased on a fleet wide basis, not unit or plant specific.

6. Mitchell Plant Review Conclusions

Maintenance is being performed in a manner consistent with generally acceptable electric utility industry practices.

Maintenance is scheduled during off peak times i.e., spring and autumn due to primary peaking loads occurring during the winter and summer seasons.

Based on maintenance practices it would be reasonable to expect that each unit at the plant could operate at a capacity factor in excess of seventy percent (70%) barring any major unexpected forced outages.

Plant staffing has been reduced by over twenty-five percent (25%) from 2018. This reduction may require hiring of temporary staff on an as needed basis. Coal disruption from the adjacent mine may result in operating limitations if not covered by increased barge delivery. The railroad that is located in the front of the facility has not been utilized over the last six (6) or seven (7) years.

Coal burn rate is approximately 15,000 tons per day at uninterrupted full load. West Virginia share is 7,500 tons per day. Based on total storage availability of 1,000,000 tons and a full-load burn rate of 15,000 tons per day equals to 67 days of coal. Obviously, the total number of days will fluctuate based on the burn rates.

AEP Service Company provides home office support e.g., environmental, procurement, and construction.

7. Mountaineer Plant Review

This facility consists of one (1) generating unit:

- One hundred percent (100%) ownership by Appalachian Power (APCo)
- Appalachian Power operates and maintains the plant.

One of a fleet of the largest single unit generators in the world:

- Commercial operations date: 1980
- Net demonstrated generation capacity: 1,320 megawatts.
- Retrofitted with control systems to reduce sulfur dioxide (SO_2) and nitric oxide (NOx) emissions.

Current approved staff size is 158 exempt and nonexempt individuals:

- Staff size is 145.
- Plant has an excellent safety record having achieved 1,433 days (as of October 19, 2022) of no injuries that are reportable.
- Major outage work is performed by contract labor.
- AEP Service Company provides home office support e.g., environmental, procurement, and construction.

Planned Maintenance Outages:

- Minor outages are on an annual basis and generally scheduled for four (4) weeks.
- Major outages are based on steam turbine requirements and phased such as to completely overhaul the machine over a period of eight (8) to twelve (12) years.
- A low-pressure turbine outage is planned for the spring of 2023.

Primary fuel is a blend of (20%) low and (80%) high sulfur Appalachian coal:

- Two (2) coal storage yards have a combined capacity of 1,800,000 tons.
- Plant full load coal burn rate is 12,000 tons per day.
- Based on a total storage availability of 1,800,000 tons and 12,000 tons per day full-load burn rate equals to 150-day supply. Obviously, the total number of days will fluctuate based on the burn rates.
- Coal delivery is either by rail (CSX) or barge (primary).
- Distillate (No. 2) oil storage capability is 1.5 million gallons.
- Coal procurement handled by AEP Service company in Columbus, Ohio.
- Coal purchased on a fleet wide basis, not unit nor plant specific.

8. Mountaineer Plant Review Conclusions

Maintenance is being performed in a manner consistent with generally acceptable electric utility industry practices.

Based on maintenance practices it would be reasonable to expect that units at the plant could operate at a capacity factor in excess of seventy Percent (70%) barring any major unexpected forced outage.

9. Amos Plant Review

This facility includes three (3) generating units capable of operating independently with common resources.

- One Hundred percent (100%) ownership by Appalachian Power (APCo).
- Units No. 1 and 2 each with a demonstrated 800-megawatt capacity for both summer and winter operation.
- Unit No. 3 is similar to Mountaineer with a 1,300-megawatt capacity. Appalachian Power operates and maintains the plant.

Units are connected to two (2) independent electrical transmission lines:

- Unit No. 1 and 3 are connected to a 765 kV transmission line.
- Unit No. 2 connects to a 345 kV transmission line.

Current approved staff size is 225 exempt and nonexempt individuals:

- Staff size in 2018 was 250.
- Major outage work is performed by contract labor.
- AEP Service Company provides home office support e.g., environmental, procurement, and construction.

Planned Maintenance Outages:

- Minor and major outages are scheduled and performed in a manner consistent with Mountaineer.
- Capital expenditures are forecasted ten (10) to fifteen (15) months in advance.
- Plans to rebuild the water treatment system have been slightly delayed.
- Unit No. 3 precipitator requires refurbishment and a detailed overhaul.

Primary fuel is a blend of low and high sulfur Appalachian coal:

- Primary fuel: coal from northern and southern Appalachia.
- Delivery option by rail or barge.
- Coal storage capacity is 1,700,000 tons.
- Based on a total storage availability of 1,700,000 tons and a full-load coal burn rate of 27,850 tons per day equals to 61 days of coal. Obviously, the total number of days will fluctuate based on the burn rates.

10. Amos Plant Review Conclusions

Maintenance is being performed in a manner consistent with generally acceptable electric utility industry practices.

Based on maintenance practices seen it would be reasonable to expect that each unit at the plant could operate at an annual capacity factor in excess of seventy percent (70%) barring any major unexpected forced outage.

Plant personnel indicated that the units are dispatched on a load following basis i.e., not base loaded or on a reduced load basis. The facilities were originally designed as base loaded units. Generally, these units run fully loaded operation in "on peak" summer and winter seasons. Otherwise, they are used as needed or in reserve shutdown. Plant is bid into the day ahead market at PJM. Note that West Virginia is a winter peak grid.

Plant coal burn rate is approximately 27,850 tons per day at uninterrupted full load. West Virginia's share is approximately 11,600 tons per day (this is a 41.6% Allocation Factor between Virginia customers and West Virginia customers).

11. Site Visits – Summary

There seemed to be a lack of detailed coordination among the divisions (power plants' personnel, fuel procurement services, and PJM bidding personnel) involved which negatively affected achieving higher capacity factors. None of the plants exhibited capacity factors approaching the 69% capacity factor the PSC had ordered on a consistent basis for the period evaluated.

Based on a visual plant walkthrough, the power plant equipment seen appeared well maintained, and if this maintenance trend continues, the plants could operate at high availability factors until 2040 and beyond, as long as the present permits were kept in place, there are no catastrophic failures occurring, and operational and maintenance procedures which CTC saw in place were continued to be followed.

There were certain facts the APCo and WPCo plant personnel were aware of as pointed out in the discussions CTC had with them. Some of these are:

- Upgrading the plants environmentally (ELG and CCR) with the goal of keeping them in service through 2040 or beyond. Publicly, AEP had announced that these plants were to request rate increases to meet the EPA requirements to keep them in-service for a longer period of time than 2028.
- The need to maintain the coal units' equipment in good condition to continue to operate for another 18 years.
- **[BEGIN CONFIDENTIAL]** [redacted] [END **CONFIDENTIAL]** There is compartmentalization of information flow between the plants and support services divisions such as fuel procurement division within the overall group's organization.
- All key personnel of APCo and WPCo "knew" or "had to know" that APCo had filed a certificate case to have the coal plants obtain certificates of convenience and necessity to provide design and operational modifications to achieve the EPA CCR and ELG requirements, and that by August, 2021, they had received approval from the Commission. Thus, the key personnel at the Companies knew or should have known that the plants were intended to be in-service through 2040 at the established capacity factor. CTC did not see evidence that actual changes were contemplated in the fuel procurement practices or improved lower variable costs of generation to achieve the goals.
- On page 211 of the transcript of the testimony of and the questions/answers involving Jeffrey C. Dial, the Director of Coal, Transportation and Reagent Procurement for American Electric Power Service Corporation from the evidentiary hearing in Case No. 21-0339-E-ENEC, on March 23, 2022, shows:
    - "Okay. So I guess I was never told by anybody that we should be procuring to a 69-percent capacity factor."
    - Page 173 & 174:.
    - Q. If I were to cite the Order, would you be familiar enough with it to —?
    - A. I am not at all.

- Q. Okay. That's fine. The RFP that you issued in September, what was the date of that RFP?
- A. I believe we went out on September 20th.
- Q. September 20th? Would you accept, subject to check, that the Commission's Order in this proceeding was on the 2nd of September?
- A. Sure.
- Q. Okay. When the Companies issued that September 20th — circa September 20th RFP, did the Companies make any effort to indicate in that RFP that there may be a significant increased need for coal supplies based on a 69-percent capacity factor?
- A. No, we did not.
- Q. That RFP looked essentially like all the other open-ended RFPs that the Companies have submitted?
- A. Yes.
- Q. Did the Companies at that point make any effort to pick up the phone, call your usual suppliers and say, hey, we've got this Order from the Commission, I want to make you aware of it, we may have an increased need in coal going forward?
- A. We did not, but I can tell you we did pick up the phone after the RFP and we did get additional supplies.
- Q. Based on the 69-percent capacity factor requirement?
- A. Based on what was available in the market at that point in tim
- Q. So unrelated — not specifically related to the Commission Order?
- A. Correct."

- The Companies should have considered longer term contracts or other contract terms or creative commercial strategies to get coal (economic) based on the knowledge that the plants were going to run until 2040. Longer term contracts with better terms and conditions would have resulted in much lower overall ENEC costs that are likely to occur in future ENEC cases.
- CTC's conclusion is that key personnel at the Companies must have known or should have known as early as November 2020 or sooner that the coal plants needed coal as low priced as possible to succeed in bidding energy into PJM and therefore, being dispatched by PJM through the period of in-service operation of the coal units. These actions would have resulted in higher capacity factors than what was achieved and possibly closer to the 69% established by the Commission. It is a fact that the Companies applied to have construction of the EPA retrofits into the rates paid by the consumers and not have the units dispatched because

they did not take care of obtaining the economic coal that would allow the units to be dispatched in PJM. This result does not appear to make common sense.

Note that given the background of the various hearings conducted during 2021 involving ELG and CCR requirements (Case No. 20-1040-E-CN), the Commission's requirements are quite clear: operate the plants at higher capacity factors to lower the costs to the consumers (the Commission used 69% as the benchmark).

APCo personnel claimed during the visits and via discovery that the 69% capacity factor requirement was a "goal" and not a requirement. They also claimed the following:

- Plants were dispatched for load based on the availability of coal economic enough to allow the dispatching of the coal plants under PJM requirements.
- Day ahead market prices bid into PJM failed in some cases due to adders that were utilized in order to avoid the dispatch of the plants when coal supplies were low and/or needed to be reserved for peak season.
- Electric generation requirements are forecasted by AEP Service Corporation.

In the order issued by the Commission on September 2, 2021 the Commission concluded that:

> *"the public interest is better served by APCo reversing that trend and focusing on maximizing generation from its owned power plants.... and determined that capacity factors of 34.7 percent to 57.3 percent should not be the basis for projections in this ENEC case.*
>
> *In more favorable market conditions, which might well occur in the future, we would expect factors in the mid to high 70 percent range. At this time, however, we will use a capacity factor of 69 percent for the Companies' projected ENEC costs. We also will assume that increased generation will result in decreased purchased power costs at the all-in weighted average purchased power cost of $35.44 per megawatt hour."*

As a result, the Commission expected that the Companies' coal plants would be operated at higher capacity factors than they have been operating, and that the Companies would effect changes in processes and decisions to achieve the 69% which was used as the capacity factor for ENEC costs projections.

Power forecasts are made several months in advance by the Service Corporation based in Columbus. These forecasts do not appear to have been provided to the plant's personnel for either a monthly or yearly time frame. These forecasts were made independent of the coal supply.

12. Additional Reviews and Evaluations

It should also be noted that during the past few years, the coal mining companies have been under pressure by environmentalists and others to stop mining coal which is a key risk to their business operations. It is expected that these mining companies would like to advise "Wall Street". that they see significant demand of coal from these power plants through 2040 and, thus, would have been willing to set up longer-term and possibly cheaper contracts which could have made the coal more competitive to burn. (This and other facts involving coal procurement were discussed by Emily Medine and Ralph Smith who testified for CAD on this subject matter and found the Companies did not meet prudency principles in their management of the coal supply for these plants).

It is of interest to note that AEP and the Companies' employees have salary/bonus programs associated with meeting corporate AEP programs and objectives such as the ESG targets established by the holding company, AEP to be "net zero" by 2050. These coal plants seemingly were being targeted to be shut down around 2028, until the request was made by the Companies in December 2020 via an official filing to the Commission for approval, to have the plants retrofitted to meet ELG and CCR EPA requirements, effectively committing to extending their plant operating lives through 2040. This emphasis on ESG and "net zero" by the governance of AEP could have affected the organizational culture their employees have been working under to the detriment of meeting the Orders issued by the Commission in maintaining the coal power plants operating through 2040 and beyond. Recently (October 2022), AEP issued a news item indicating that their company and subsidiaries will be "net zero" compliant not in 2050, but earlier, in 2045. This further indicates the organizational culture their personnel were and are currently working under.

It is also important to note that the Companies filed in December 2020 for the opportunity of making the environmental changes required by new EPA regulations affecting ELG and CCR. The Companies initiated this filing requesting to increase the rates to cover the costs of the plants' modifications. This request would allow the coal plants to be in service through 2040. Thus, the Companies should have known that a reliable and competitive supply of coal would be required for the longer term.

It is inconceivable to CTC to think that the units would be retrofitted to meet EPA requirements so that they can be dispatched by PJM through at least 2040, and then, not have the competitive cost coal on-hand sufficiently to be successful at being PJM dispatched, while at the same time, the rate payers incur higher rates for retrofitting the units. The Companies benefit from a return on their new investment as reflected in higher rates, while the ratepayers do not benefit from the operations of the coal plants.

In addition, it is worth noting that as of the end of 2020, the Companies had coal under purchase order to be delivered at competitive prices, which the Procurement Division negotiated to be negated. However, it appears that the Companies did not provide the coal supplier with specific new schedules of when these amounts of coal could be delivered (only delayed to 2022). Thus, there appeared to be no evaluations made by the Companies to have competitive coal for these plants to be dispatched at the capacity factors the Commission had made specifically known throughout 2021 and ultimately reflected in the Order given on September 2, 2021 under Case No. 21-0339-E-ENEC.

The historical fact is that the coal plants were not dispatched at the capacity factor of 69% which the Commission indicated would be an appropriate capacity factor. The Companies maintain that the plants were not competitive (due to fuel costs and the lack of available coal) in the bidding for PJM and thus, were not dispatched by PJM.
While this may be true, CTC found no credible evidence that specific actions or decisions were taken by the Companies such as having brainstorming groups established to discuss how they could lower the variable generation costs of the plants including fuel to allow them to be dispatched by PJM and meet the PSC capacity factors. Some of the concepts involve a cost benefit evaluation of efficiency improvements through which an appropriate capital investment could have provided higher efficiencies to these coal plants with a subsequent reduction in coal consumption and CO_2 releases. Some of these are discussed in the Conclusions Section 14.

CTC has not seen any specific strategies or techniques or studies which were attempted to be used to negotiate with existing or new coal suppliers to lower fuel costs to allow for competitive dispatching of these plants to achieve the Commission's established capacity factor. In fact, it appears when no responses were received from the first coal supply RFP the Companies issued in the spring of 2021, the Companies did not place calls for further details regarding the lack of bids, thereby passing on the opportunity to engage in detailed negotiations with coal suppliers earlier in the year and prior to the substantial increases in pricing. The Companies waited until the fall of 2021 when coal supplies were almost unavailable to have any negotiations for coal supplies.

APCo and WPCo have been placing reliance on PJM energy supply in preference to the self-supply options which the Commission was looking to preserve via its various Orders and statements made at the hearings. The Companies did not follow through on the requirements as stated by the Commission.

Based on the above, we see little evidence that the Companies committed internally to attempt to achieve the Commission established capacity factor, in operating these plants from September 2021 through September 2022.

13. Fleet Capacity Factor

The West Virginia located plants under ownership by either Appalachian or Wheeling Power includes the following facilities:

- Amos plant units number 1, 2 and 3
- Mitchell plant units number 1 and 2
- Mountaineer unit number 1

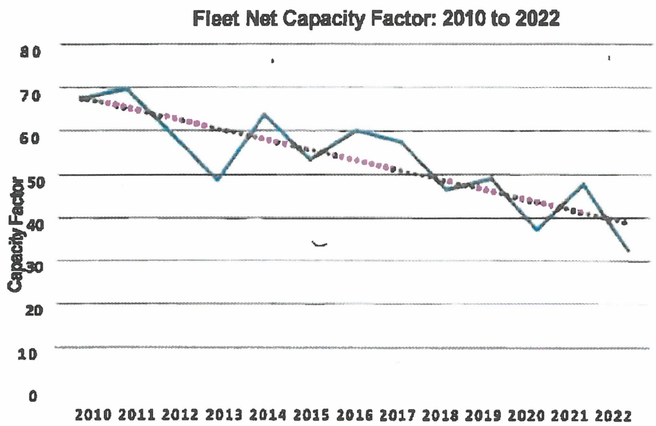
All of these plants employ bituminous coal as their primary fuel for the production of electrical power, which is transmitted out from the plants by means of either the 345 kV or 765 kV high voltage transmission lines.

The net capacity factor data for these units were obtained for the years 2010 until 2022. The generally accepted definition of net capacity factor is given as:

> *Net capacity factor means net actual generation divided by the product of net maximum capacity times the number of hours the unit was in the active state during the assessment year.*

By industry practice the number of hours used for calculation is 8760 or the maximum in an average (non-leap) year.

The net capacity factors averaged for all plants is shown in the figure below. A trendline has been added to demonstrate the changes from 2010 to 2022. The data clearly indicates that the net capacity factor has declined over the twelve years from 2010 onward.



For the period covering September 2021 through September 2022 the net capacity data is presented in the table below:

TABLE 1

Net Capacity Factors - Percent
Amos, Mitchell and Mountaineer
September 2021 to September

Plant/Unit	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Period
Amos Unit	74.8	52.3	12.5	86.1	53.7	41.0	54.2	51.4	43.1	52.3	44.2	62.2	35.4	51.2
Amos Unit	5.8	0.0	0.0	46.9	49.5	7.5	0.0	4.2	38.0	43.6	52.2	58.3	25.9	25.8
Amos Unit	77.6	2.8	0.0	51.4	63.4	52.6	0.0	0.0	0.0	0.1	49.4	52.7	11.8	27.8
Plant	57.2	15.6	3.4	59.6	57.0	37.1	14.8	15.2	22.1	26.2	48.8	56.8	22.1	33.6
Mitchell	47.2	9.6	0.0	0.0	37.7	0.0	0.1	24.5	45.0	50.6	54.8	70.2	46.1	29.8
Mitchell	55.2	45.5	29.9	63.4	55.8	39.0	0.0	23.6	13.5	23.4	39.5	23.4	0.0	31.7
Plant	51.3	27.8	15.2	32.1	46.9	19.7	0.0	24.0	29.1	36.8	47.1	46.5	22.8	30.8
Mountainee	28.4	0.0	0.0	58.5	82.3	57.7	3.6	0.0	0.0	10.7	75.7	72.7	25.3	32.0
Rollup	40.8	13.9	14.4	48.4	55.4	36.8	8.3	14.1	19.0	25.6	54.4	57.7	23.0	32.5

A quick glance at the table above, reveals that as a fleet the plants did not achieve the capacity factors established by the Commission (69%). In fact, they were inconsistent with the requirements established by the Commission. It defies common sense that the Companies with coal power plants in West Virginia for many years, which have been in the business of coal procurement from West Virginia sources also for years and years, could not obtain the coal from West Virginia needed to be dispatched at higher capacity factors than shown in Table 1.

Figure 1 – The Companies' Fossil-Fueled Generating Fleet NCF- March 2021 through February 2022.

APCo & WPCo
Fossil-Fueled Generating Fleet
Net Capacity Factor [%]
March 2021 through February 2022

Unit	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	[illegible]
Amos Unit 1	7.87	0.00	0.00	45.70	88.56	84.09	74.82	52.34	12.48	86.11	53.73	41.00	45.73
Amos Unit 2	0.00	37.00	63.55	77.43	84.84	49.82	5.80	0.00	0.00	46.92	49.52	7.45	47.14
Amos Unit 3	35.26	0.00	71.67	80.01	54.57	76.12	77.56	2.78	0.00	51.3[illegible]	63.15	52.58	47.14
Amos Plant Rollup	18.13	18.10	49.89	68.04	72.13	71.12	57.22	25.55	3.41	59.63	56.85	37.10	43.57
Mitchell Unit 1	12.93	15.18	0.00	55.90	54.13	48.20	47.19	9.64	0.00	0.00	37.70	0.00	23.27
Mitchell Unit 2	9.10	10.72	65.03	51.02	73.31	77.20	55.23	45.54	29.93	63.42	55.82	38.96	47.94
Mitchell Plant Rollup	10.99	12.92	32.93	53.03	62.73	61.35	51.26	27.87	15.16	32.12	46.88	19.73	35.77
Mountaineer Unit 1	60.41	60.76	67.23	84.56	90.49	89.87	38.36	0.00	0.00	58.55	80.26	57.67	58.64
Coal Unit Rollup	27.[illegible]	24.41	60.27	65.[illegible]	73.75	74.78	49.08	15.31	5.79	51.99	59.99	37.11	44.00
Ceredo Unit 1	0.65	5.46	5.30	11.55	9.34	11.25	3.62	13.09	17.13	5.00	5.46	2.89	7.51
Ceredo Unit 2	0.65	5.17	3.02	11.52	8.61	10.90	3.02	12.86	17.79	4.90	5.48	2.90	7.25
Ceredo Unit 3	0.66	5.25	2.92	11.64	7.83	10.91	3.00	12.42	18.59	4.55	5.84	2.94	7.22
Ceredo Unit 4	0.65	5.19	4.25	12.32	8.66	11.25	3.09	13.18	18.02	4.99	5.80	2.87	7.54
Ceredo Unit 5	0.66	4.22	2.88	11.45	7.67	10.58	3.36	11.80	17.48	4.23	5.49	2.88	6.98
Ceredo Unit 6	0.65	4.22	2.58	10.84	9.98	10.77	2.96	12.18	17.16	4.10	5.46	2.85	6.93
Ceredo Plant Rollup	0.65	4.92	3.55	11.55	8.52	10.95	3.01	12.59	17.20	4.63	5.59	2.89	7.23
Clinch River Unit 1	0.00	0.00	7.60	6.41	3.44	11.29	0.24	1.93	4.52	0.00	0.00	1.81	3.12
Clinch River Unit 2	0.00	5.12	7.54	4.99	3.64	6.82	0.00	1.81	12.04	0.00	0.00	0.00	3.53
Clinch River Plant Rollup	0.00	2.59	7.57	5.69	3.54	9.08	0.12	1.87	8.32	0.00	0.00	0.94	3.32
Dresden 1A	88.96	52.41	86.26	81.96	79.94	80.93	27.46	11.98	94.28	91.22	94.35	90.88	73.34
Dresden 1B	88.37	51.95	85.93	81.57	79.51	80.39	27.36	12.32	93.59	90.84	96.53	91.07	73.21
Dresden 1S	76.69	47.59	76.33	76.22	74.09	72.49	74.75	9.75	86.94	74.93	86.95	76.59	65.76
Dresden Plant Rollup	84.00	50.39	82.29	79.80	77.53	79.82	28.37	11.72	91.21	84.76	92.10	85.37	70.36
Aggregate Rollup	29.26	24.02	46.45	62.00	65.19	65.15	40.80	13.92	14.38	48.39	55.35	36.79	41.97

In Figure 1 above, the capacity factors from March 2021 through February 2022 are presented. It is curious to see in the summer of 2021 data, the coal plants were burning as much competitive coal as possible giving the impression that the operators wanted to address the summer peaking desires of PJM while getting rid of the excess coal from 2020. In testimony provided by Mr. Jeffrey Dial during the hearings of March 22, 2022, it comes out that the Mr. Dial determined in July 2021 that the Companies had enough coal to manage their needs in the winter 2021/2022 even though outages were being planned. Yet, it was determined in August that the plants did not have the fuel available to meet winter requirements; only one month later.

Forced Outages

Electric utility industry definitions for outages vary by type with definitions established by the regional transmission operator, PJM in West Virginia or the North American Electric Reliability Corporation ("NERC"). The generally accepted definition of a forced outage is:

*Forced Outage means an **unplanned outage** of one or more of the Facility's components that results in a reduction of the ability of the Facility to produce Capacity but specifically excludes any Maintenance Outage or Planned Outage.*

A plant's net capacity factor is reduced by either a forced or planned outage. The rate of forced outages is used to evaluate the reliability of a plant to produce power and is often used to indirectly evaluate the condition of the plant and by extension the maintenance management of the facility.

There are several types of forced outage metrics employed by the industry. For this review two (2) were provided:

- Equivalent Forced Outage Rate - EFOR

  *Which are the **hours of unit failure** (unplanned outage hours and equivalent unplanned derated hours) given as a percentage of the total hours of the availability of that unit (unplanned outage, unplanned derated, and service hours).*

- Equivalent Forced Outage Rate on Demand - EFORd

  Means a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.

The EFORd for the fleet of six (6) units was obtained. The data was then averaged to present a fleet wide percentage shown in the chart below:

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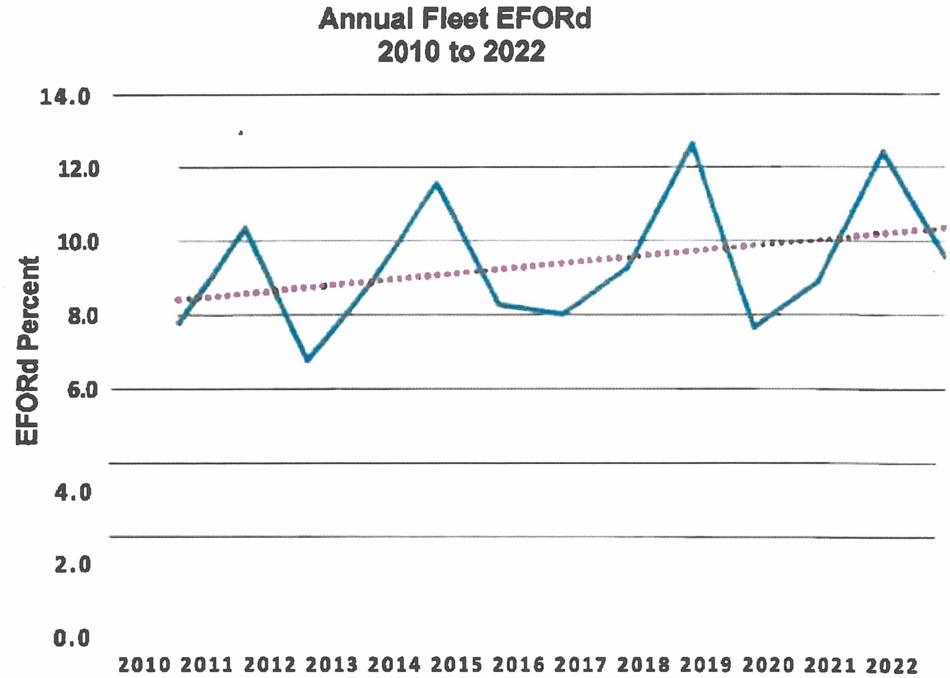

Results

The outage rate for the fleet has been, on average, increasing for the period from 2010 to 2022 as demonstrated by the linear trendline in the above graph. Since by definition the net capacity factor is reduced by planned and forced outages, an increasing forced outage rate reduces the ability of the plants to provide electric power on demand. In this case, shown above, the net capacity factor is being reduced by ten (ten) percent on the average.

It is not uncommon to anticipate a decrease in plant availability (caused by planned and forced outages) as a plant reaches an age of 30 to 50 years. Nevertheless, industry knowledge and experience in recent years has expanded to improve the availability and efficiency of older facilities with an associated capital funding, reduction of CO_2 and some potential additional expenditures for inspection and maintenance programs.

14. Conclusions

In response to Q 6.4, the Companies indicated while they do not have the written business plan like the IPPs do, "the Companies' goal in assessing plant conditions and budgeting/planning necessary capital and O&M projects at their coal-fired plants, from year to year, is to ensure that the plants continue to be available when called upon by PJM (i.e., available for economic dispatch) to meet customers' needs, particularly in summer and winter peak periods when market power prices are typically highest. The Companies' plant employees, including managers, follow those budgets and plans. As regulated utilities, the Companies focus on meeting projected customer needs at the lowest cost via the economic dispatch of their plants." As a result of its independent evaluation, CTC did not find that these important goals were met resulting in a significant violation of the Companies' responsibilities toward its customers.

And in response to Q 6-13, the Companies indicated "Prior to 2021, the Companies did not have intentions to retire the plants before December 31, 2028. The plants were being depreciated through 2040 in West Virginia based on their expected life. In 2020, the Companies filed an application with the Commission for authorization to make modifications at the Amos, Mountaineer and Mitchell plants to comply with federal environmental regulations which would allow the plants to remain operating beyond 2028 and through 2040."

As early as a November 5, 2020 AEP Press Release, AEP publicly announced compliance plans covering two recently revised U.S. Environmental Protection Agency's (EPA) regulations involving Coal Combustion Residuals (CCR) rule and Effluent Limitation Guidelines (ELG). AEP indicated plans to continue operating the following West Virginia coal-fired plants with CCR and ELG investments:

- Amos Plant (2,930 MW), Winfield, West Virginia
- Mountaineer Plant (1,330 MW), New Haven, West Virginia
- Mitchell Plant (1,560 MW), Moundsville, West Virginia

The Companies' request to increase rates to cover new environmental requirements for the coal power plants and keep them in-service until 2040 was also known by the Companies by the third quarter of 2020 when these alternatives were offered by the Companies to the Commission in a filing on December 23, 2020.

From our discussion of responses Mr. Jeffrey Dial, the Director of Coal, Transportation and Reagent Procurement provided to questions during the hearing in Case No. 21-0339-E-ENEC on March 23, 2022 presented in Section 11 Site – Summaries of this report, we find that:

- He had not seen the Commission's order of September 2, 2021;
- He was not aware that he had to procure coal to meet the 69% capacity factor or just higher than had been achieved annually (of roughly 14 MM tons of coal); and
- He had only overseen the procurement of 9.5 MM tons of coal for 2022.

The conclusion we arrived from the above responses is that the coal plants would be operated through 2040 (to the end of their economic life) and be economically dispatched by PJM using the standard processes and procedures AEP Services had used all along without addressing the order from the Commission of September 2021.

The fact that the Companies had publicly indicated the coal plants will be in-service to 2040 and the reinforcement by the Companies' application to obtain approval of additional rates to effect the retrofits EPA had requested would further support the plants' operation through 2040.

Yet, no specific programs, steps nor actions were taken for the longer-term procurement of the coal and chemicals to allow operation at higher capacity factors, closer to the 69% the Commission ordered. This last action could have eliminated the event of "no coal available in the West Virginia market" which has been used as the reason by the Companies to justify why they could not meet the 69% factor.

This begs the questions why the request for retrofits of the plants to cover EPA requirements was done with associated rate increases while the supply of the fuel was not procured economically to dispatch the units (at higher capacity factors as the Commission was requesting and requiring). In addition, the Companies did not appear to be hedging nor applying other longer term strategies in fuel procurement to obtain the economic coal which would allow the coal units to be dispatched by PJM.

Even long-term storage approaches were not considered. CTC did not see in the documentation that steps were studied and/or implemented to generate more efficiently or innovatively such as using high efficiency large motors or upgrading the heat cycles of the coal plants to run more efficiently and at lower house loads. Not even upgrades to the equipment were identified by the Companies to allow the plants to cycle more efficiently than originally designed. (They were designed to be based loaded).
No consideration was given to negotiating with PJM that these coal plants be declared "must run" base loaded plants so as to improve the resiliency, reliability and safety of the grid as more and more intermittent renewables are added. Note that the grid would be

more stable if these coal plants were run as base loaded particularly in the winter when West Virginia has its peak loads.

The common sense conclusions which can be arrived at is the West Virginia ratepayer were paying rates for coal units to last until 2040, while no longer-term or creative approaches to obtain the fuel needed for the higher capacity factors as required by the Commission were being pursued. Basically, the ratepayers are paying rates for plants which are not being dispatched to their full abilities due to the poor sense or judgement of the companies.

Below the general events timeline is presented: (Detailed Timeline is presented in Appendix A).

1. November 5, 2020, AEP News release.
2. December 23, 2020 Case, No. 20-1040-E-CN New Case Filing Received.
3. In July 2021, a West Virginia law was passed that all coal plants must have fuel contracts in place to cover a 30-day supply.
4. August 2021, Commission approves rate increases requested by Companies in late 2020 to cover the CCR and ELG costs allowing the Companies to operate the coal plants through 2040.
5. In September 2021, Commission issues an Order which clearly establishes 69% as a capacity factor anticipated to maintain the economic value of the coal units and with the preference of self-generating rather than buying power from PJM.
6. During the months of September, 2021 through September 2022, the fleet of coal plants consistently failed to meet higher capacity factors. On an unit basis, only seven (7) out of the 84 monthly unit observations met the higher capacity factor, as shown in Table 1. The overall aggregate net capacity factor on a yearly basis after the order was issued was 32.6%, significantly lower than the 69% capacity factor established by the Commission.

Data was reviewed which covered the ending coal inventory for the period January 2020 through February 2022, on a monthly basis, for the Mountaineer, Amos and Mitchell plants. Using the full load (100% capacity) burn rates for the steam generators, the number of days of coal stored at each site is calculated and presented in graphic format. In turn the full load graph is overlaid with an estimate of the equivalent days of coal available if a sixty nine percent (69%) capacity factor had been in force during the entire period.

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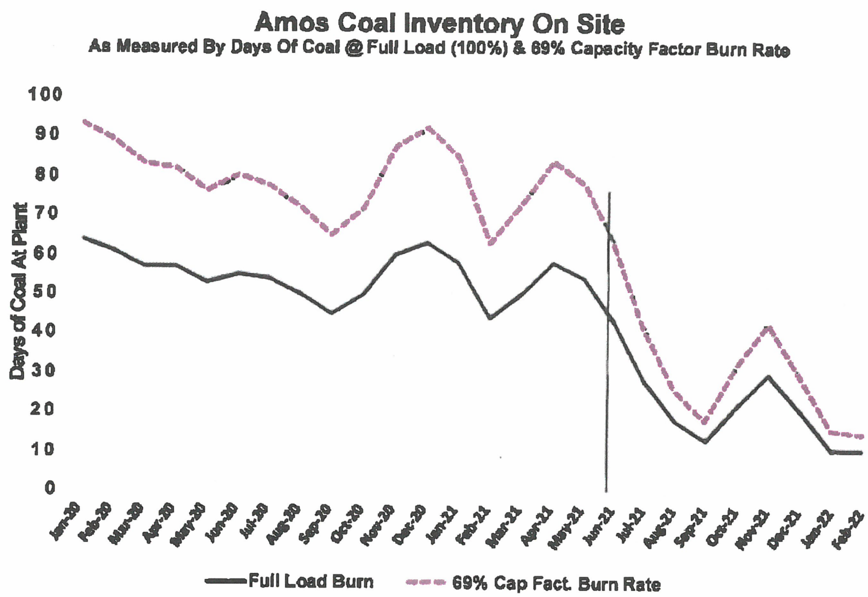
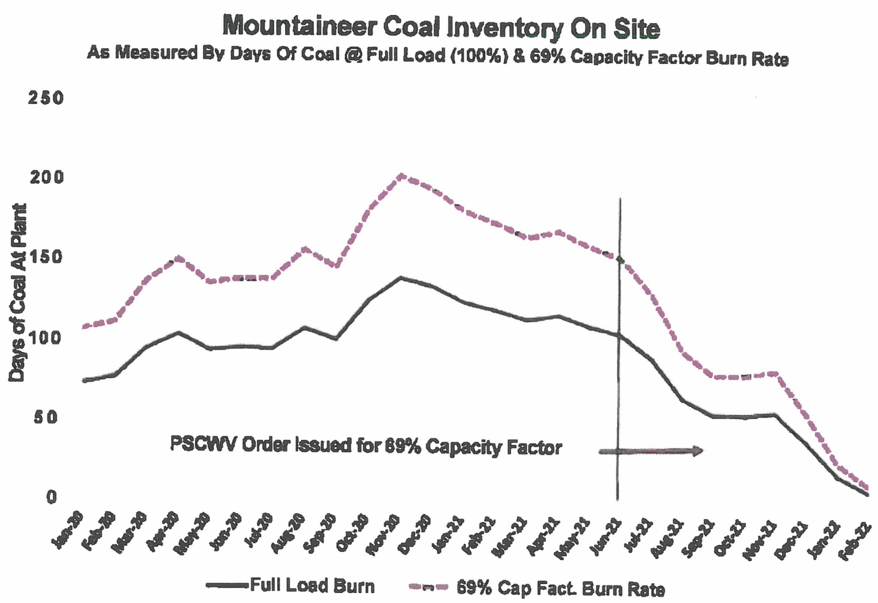
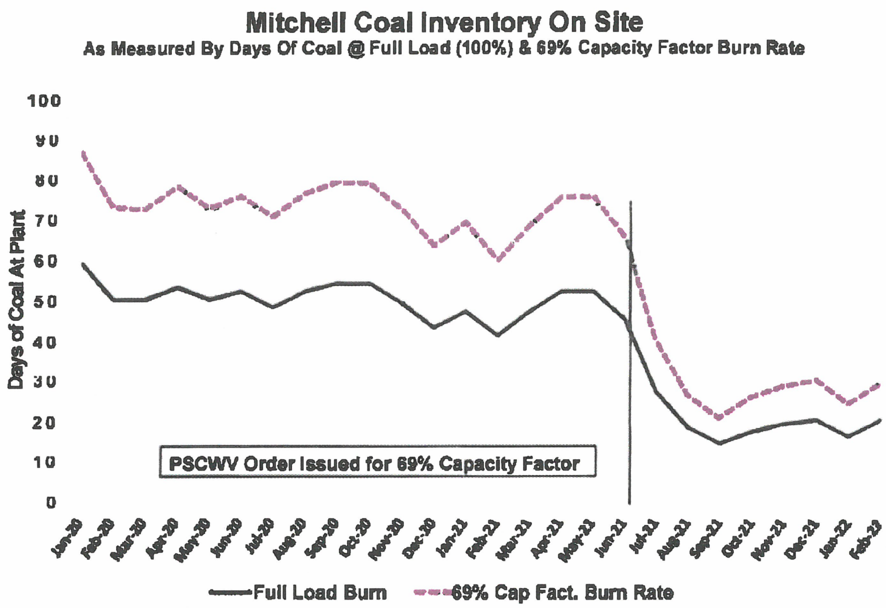






The Public Service Commission's order for maintaining a 69% capacity factor on the output of each plant was decreed in September of 2021. The charts data was extrapolated in reverse for the purpose of demonstrating the potential inventory days had the 69% rule been in effect historically. In other words, how many days of coal stored would have been needed to maintain a 69% capacity factor.

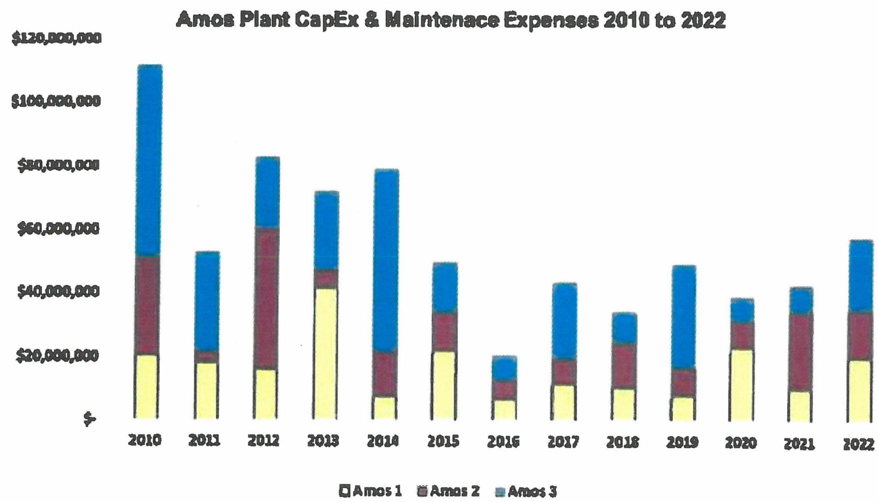
Of note is the dramatic decline in inventory on site, particularly for Amos and Mountaineer, which began after November 2020. The decline continued further even after the 69% rule went into effect. In fact, the inventories became dangerously low in February 2022 to the point where operators were near reclaiming or "scraping the dirt" from the coal yard. Specifically, the remaining days of coal at a burn rate for 69% capacity factor to be stored at Mountaineer and Amos in February 2022 would have been:

- Mountaineer: 12 days
- Amos: 15 days
- Mitchell: 30 days

These were way below the required 30 days of coal storage the plants would have needed to meet legal requirements.

Maintenance management practices for all the plants appears to be uniform in implementation and they are being performed in a manner consistent with generally acceptable US electric utility industry practices. The units appeared to be in good shape given their operational age, to operate for another 18 years (2040). Note that they are not being operated at their full ability to be available for higher net capacity factors.

Capital and maintenance expenses for 2010 through 2022 (October) are presented in the graphs below by power station with colors delineating the Units within a station. We are presenting the data for the capital maintenance and operations received via responses to Question Staff 2.3, Attachments 1, 2 and 3. All the costs are in nominal dollars. If we were to consider inflation, we would see the overall expenditures in maintenance and capital maintenance go down as a function of time from 2010 through 2022, except for major projects in Unit 3 of Amos and overhauls of boilers and turbine generators for Mitchell Units 1 and 2, and Mountaineer Unit 1.



Unit 3 had major boiler overhauls in 2010 and 2014

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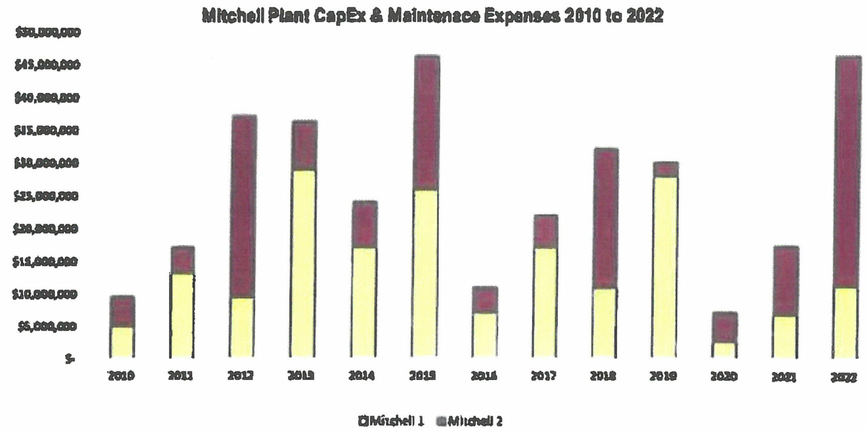
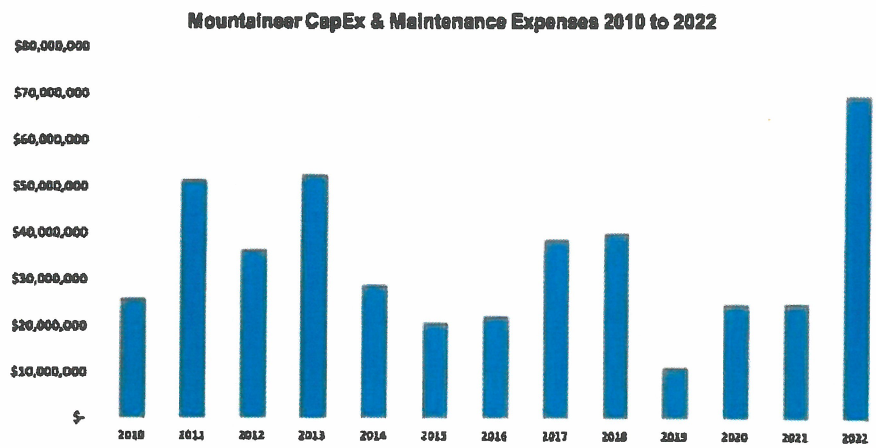


The high maintenance cost years (2012 and 2022 included major overhauls of the boiler and precipitators. In 2022, the effluent water treatment facility was added.



Maintenance Culture

However, plots of maintenance costs over the period of 2015 to 2021 provided by Staff clearly point out a decrease of maintenance costs over the period and even coming as early as 2010 to 2015 for the Amos and Mountaineer coal plants. These plots are shown below.

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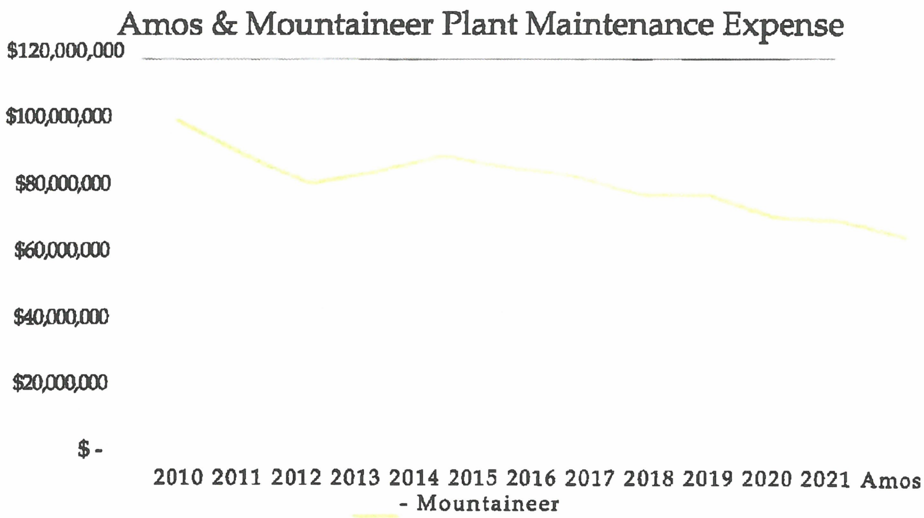

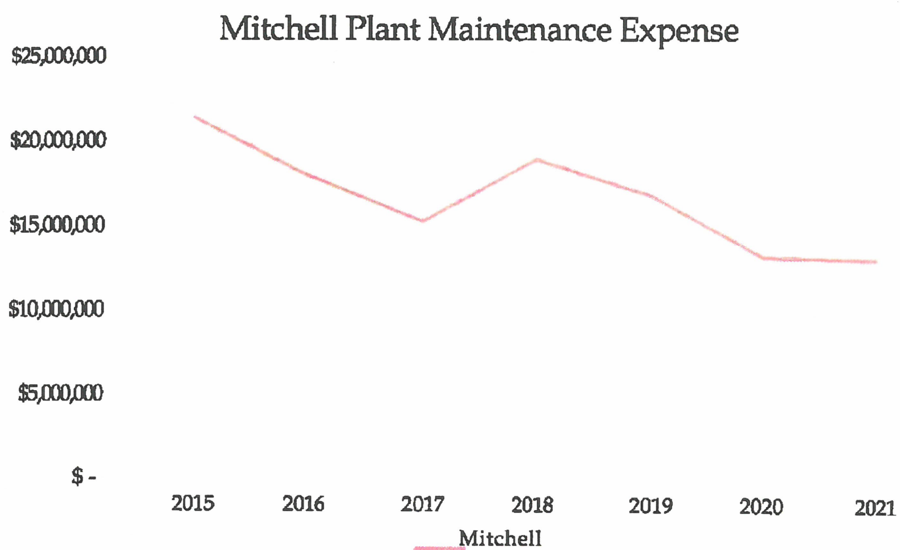

CTC would have expected an increase in maintenance costs and capital investments over the same periods if the plants were being utilized at greater capacity factors with upgrades been implemented during these maintenance periods so that the plants could operate more efficiently. It should be noted that CTC noticed that maintenance personnel have been under the pressure to reduce their maintenance costs as part of the operating culture as noted during the visits to the plant sites.

However, based on the maintenance practices CTC witnessed during the site visits, it would be reasonable to expect that each unit at each of the plant sites could operate at a capacity factor around seventy percent (70%) barring any major unexpected, forced outages. The plants could have achieved the 69% the Commission directed the Companies to meet if adequate coal was available on hand during the period under review.

The excess coal available to be supplied in 2021 via a Purchase Order was negotiated out by the Procurement Division of the Companies and no new schedule of deliveries appeared to have been provided to the coal supplier. In such event, the result was there was no coal available to be burned competitively at the plants during the period reviewed. It should be noted that CTC has not received any indication that the Companies' processes have changed, or new decisions or studies made to improve the capacity factors of these plants as of the time of the site visits (mid-October 2022).

Generation dispatch and coal procurement are made at AEP Service Corporation and appeared not to be well coordinated with local coal plant units' staff and other APCo and WPCo personnel.

While central fuel procurement staff were aware of the potential of negotiating advantageous fuel pricing contracts to cover longer terms for the coal from their suppliers, there appeared to be little consideration at negotiating lower cost fuel supplies to dispatch at the higher capacity factor requirements the Commission discussed with the Companies during hearings held in 2021 and 2022.

Plant dispatch and fuel sources appear to be compartmentalized in that each plant does not have a significant input into these crucial areas to be successful in bidding PJM. Coal procurement is conducted fleet wide and not tailored to the individual plants. Coal supply contracts "roll off" at the rate of one third per year indicating short term contracts.

No changes or commitments in the Companies' processes were detected by discussions at the sites, review of testimonies, and responses to interrogatories which would indicate that the Companies personnel were instructed to accomplish whatever was possible including changes to their processes to increase the capacity factors of the power plants by lowering the costs of operations while bidding PJM.

This scenario reflected the overall Companies' strategy to participate in PJM, whereby PJM becomes the primary supplier of the generation. CTC did not detect any activities discussed, which indicated that the Companies wanted to resort to the coal plants being in-service in a self-generating mode at the Commission's established capacity factor or near it. This further allows the holding company, AEP, to indicate to Wall Street that it is meeting its long-term revised ESG goals announced in early October 2022 to be met by 2045 (five (5) years earlier than originally established).

It should be noted that CTC did not see any programmatic attempts to achieve higher capacity factors than the plants were achieving in the recent past, as reflected in the existing procedures of fuel procurement, maintenance operations and bidding energy into PJM which were not changed.

The Companies should have considered longer term coal supply contracts based on the knowledge that the coal plants were proposed to run until 2040. Longer term contracts would have resulted in lower coal prices ultimately reflected in lower PJM bids, and consequently, higher capacity factors, which would be reflected in lower costs as purchasing excess capacity would result in a credit to overall ENEC costs. It is important to note that as early as November 5, 2020 an AEP news release clearly indicated that the Companies were to add:

> ***"Dry bottom ash handling systems or new lined ash ponds that meet the requirements of the EPA's CCR and Effluent Limitation Guidelines (ELG)rules will be built and operational in 2023 at four other power plant sites. Existing ash ponds at these sites will be closed, and the ash will be moved to regulated landfills. Plants that AEP plans to continue operating with CCR and ELG investments are:***
>
> > ***Amos Plant (2,930 MW), Winfield, West Virginia***
> > ***Mountaineer Plant (1,330 MW), New Haven, West Virginia***
> > ***Mitchell Plant (1,560 MW), Moundsville, West Virginia"***

On December 23, 2020 the Companies announced their filing with the Commission to cover the costs of the environmental upgrades with the following introductory statement:

> ***"December 23, 2020***
>
> ***CHARLESTON, W.Va. - Appalachian Power, along with Wheeling Power, today requested permission to make upgrades and recover costs associated with meeting recently revised environmental regulations at the John Amos, Mountaineer and Mitchell plants in West Virginia. These rules apply to the ash handling and wastewater discharge systems at the facilities.***
>
> ***The company requested Certificates of Public Convenience and Necessity to perform work at the three plants, and rates to begin recovery of the costs associated with those environmental improvements, in a filing with the Public Service Commission (PSC) of West Virginia. If approved by the Commission, residential customers using 1,000 kWh/month would see a 41-cent monthly increase beginning in September 2021.***

The total investment at the three plants is approximately $384 million.

"This investment in our existing coal plants is all about balance," said Chris Beam, Appalachian Power president and COO. "While we are planning investments in renewables in both Virginia and West Virginia, consistent with state legislation, we also need to invest in these plants because they will continue to play an important role in maintaining affordability and reliability for our customers."

Today's filing is the first step in obtaining the regulatory approvals necessary to implement the compliance plans the company filed last month with the U.S. Environmental Protection Agency to meet its Coal Combustion Residuals (CCR) and Effluent Limitation Guidelines (ELG) rules.

"For each plant, we analyzed the most cost- effective way to meet customers' energy needs," Beam said. "We looked at the level of investment needed to comply with the rules, remaining operating life of the plant and potential future compliance".

Note that the Companies determined these environmental upgrades to be a cost-effective way to meet customers' energy needs. The Commission approved these upgrades by August 2021. The key personnel of the Companies knew in 2020 that if the filing was approved by the Commission these plants would be operating for the longer-term and they should have planned for the availability of the coal plants and of the lowest cost fuel which would have led to longer and better cost supply contracts. The Companies began the process of recovery of the proposed CCR and ELG investments on the filing of December 23, 2020 (Case No. 20-1040-E-CN). The rates were approved on September 1, 2021.

We have seen in the power industry many power plants which had their own individual business plans. We have requested business plans from the Companies for the power plants being reviewed and were not able to obtain the plans, or they do not seem to exist for the individual power plants or for the total group of plants. We wanted to confirm that the outages the coal plants were under from September 2021 through April 2022, were planned maintenance outages in the business plans for 2021 and 2022 and not the operators taking advantage of the "no coal" scenario to conduct additional maintenance on these coal units. Further, these business plans would also shed further light on the longer-term plans for each unit within each coal power station.

Coal "on the ground space" at the time of the site visits (October 2022) appeared to be adequate in accordance with the "Base fuel supply requirements for electric grid resiliency in West Virginia" requiring that 30-day supply contracts be in effect for all power plants in West Virginia. This 30-day supply contract requirement was added by the Legislature in July 2022. CTC would recommend that the Commission considers proposing specific language to the legislature to clarify that the coal is to be "on hand" at the power stations' sites and not just included in a Purchase Order for future delivery, to better define the requirements under the implementation of this law.

[BEGIN CONFIDENTIAL] [redacted]. [END CONFIDENTIAL] This area should be further evaluated by the Companies to see what can be done in negotiations to obtain supply and pricing more commensurate with their abilities to negotiate. We also conclude that inadequate risk management techniques nor upgrades in the processes were used to maintain the coal units operating at higher capacity factors as the Commission directed. As a result, the activities conducted by the Companies' personnel were considered "as usual" with little acceptance of what the WVPSC was requiring relative to the in-service use of the coal plants.

Additionally, we conclude that the decisions taken, and the processes used by the personnel responsible did not include on a "known or should have known" basis the requirements established by the Commission, and therefore, are judged to be "imprudent" relative to meeting these Commission requirements.

In reviewing the testimony previously given in both Cases No. 21-0339-E-ENEC & 22-0393-E-ENEC, CTC arrived at additional conclusions discussed below:

- **Fuel purchasing practices**

  Fuel procurement practices and strategies could have been modified to provide the opportunity to obtain coal at better competitive prices than the spot market, given the market clout that the Companies have had over many years. Some of these negotiations could have been welcomed by the coal suppliers, since longer term sales of coal could provide them a better outlook in Wall Street. No clear attempt by the Companies was detected in reviewing this potential area of lower costs to make the plants more competitive and obtain higher dispatching than they obtained.

  In addition, CTC did not see that the excess coal which was negotiated out of the contracts in early 2021 were re-scheduled to be supplied later in 2021 or into 2022 when the coal supplies were needed to support higher capacity factors.

- **Power plant utilization**

  While CTC has indicated that the plants were found to be in adequate condition to operate at higher capacity factors, CTC did not see any steps had been taken by the Companies to study what could be done to make the plants less costly to operate and develop higher dispatching within PJM. As a result of this failure, the plants effectively were destined to be operational at lower capacity factors than that directed by the Commission of 69%. Technical concepts which could have been considered unit by unit with an appropriate cost/benefit evaluation to improve plant efficiency and lower CO2 emissions could include:

- o Combustion system optimization and boiler upgrades including increasing air heater surface
- o Use of variable frequency drive upgrades
- o Optimizing condensers
- o Flue gas heat and moisture recovery
- o Improvement of process controls
- o Refurbish of steam turbines

Other management concepts could involve

- Storing coal supplies at locations other than the power plants to back up the availability of coal for the plants. Good risk management principles apply here.
- Negotiating longer term contracts for the coal supply as soon as the decision was made to accomplish environmental retrofits for the coal plants (AEP news release of November 2020).
- Using the old PO for coal supply and, rather than suspending the deliveries, having the coal placed into an intermediate storage or on site at one of the plants and transported to the available coal units to burn the coal when it was needed.

- **Bidding strategy to sell generation into the PJM energy market.**

CTC did not see during its review of the documentation provided that any bidding processes were changed, enhanced, or modified to assist these plants during the time period to achieve higher dispatchability factors. No specific attempts to lower the variable costs of generation were seen by CTC. In fact, adders were placed on the bidding prices to assure that the plants available were not dispatched to avoid having them end up with no coal piles available to operate.

We conclude that there seems to be a reluctance to rely on the self-generation option using the coal power plants which are recovered through rates.

- **Extent to which generation from the Companies' plants failed to clear the PJM energy market during hours of PJM energy prices were more than the incremental variable costs of self-generation.**

  Based on the review of the table of capacity factors reported for the coal units, we find that no significant attempts were made to dispatch these units except to follow the standard procedures of fuel procurement and bidding which have been used for a long period of time by the Companies' personnel. In addition, the use of "adders" to the bidding price, were utilized to ensure these coal plants would not be dispatched by PJM and avoid "running out of coal at the sites".

  This approach while it may meet ESG goals, does not support the requirements of dispatchability and associated capacity factors which the Commission established.

- **Reliance on PJM energy relative to self-supply options.**

  It should be noted that the Companies' personnel seem to look at PJM as the ultimate supplier of choice for the power to be distributed by the Companies. The option to self-generate does not appear to have any higher priority even after the Commission issued the various Orders which result in the units being in-service through 2040 and with high-capacity factors as directed by the Commission.

  On an added note, almost all countries that have switched away from fossil fuels before having available reliable electric infrastructure of generation including fuel supply, transmission and distribution, and controls and communications are having major difficulties keeping reliable service to their customers.

  It is important that our nation, which has been very fortunate for its abundant and low-cost energy, not be caught in the same cycles as some of these nations have done, as they prematurely and in some cases without a detailed plan, eliminated fossil fuels. Recently, Germany and the UK have re-opened some of their shutdown coal plants to further generate electricity.

  Common sense dictates that no shutdowns of fossil fuels, nuclear and other base loaded power plants should be considered until the renewables and other forms of non-carbon generation are in service (not just planned), and the available and/or new transmission, distribution and controls needed for resilience, reliability and safety of generation and delivery of electricity to the customers are in place. This approach would allow the safe, stable and reliable switching to these new forms of energy as a result.

CTC perceives that the intent of the Commission is to see that reliable power service is provided using the present base loaded coal plants in rate base (paid by rate payers) until the renewables' generation and associated infrastructure are ready to work with them in an integrated basis.

CTC did not detect serious attempts by the Companies to get organized to implement actions to achieve the Commission established capacity factors during the period from September 2021 through September 2022 for these coal units/plants. CTC concludes that the decisions taken or not taken by the Companies are contrary to the prudency of addressing the Commission established capacity factor of 69% in using the rate-based coal power stations on a self-generation mode.

In Table 1, we computed that the achieved aggregate capacity factor for all reviewed plants from September 2021 through September 2022 to be 32.5% on an annualized basis.

Given the conclusions indicated above, CTC believes that the Companies have not complied with the Orders of the Commission relative to self-generation and capacity factors for their coal plants during the Prudency Period, and thus, should not be able to recover the full amount requested for the under – recovery payments during the period of the Prudency CTC just conducted.

CTC suggests the under-recovery of $ 350,507,771 be withheld until actions are taken by the Companies and confirmed independently, which clearly show compliance with these Orders. Once the Companies notify the Commission that they are complying, then a compliance due diligence audit should be conducted to ascertain this compliance.

Once the compliance is ascertained, then the Companies should be given credit for the capacity factors achieved on the basis of the average capacity factor in aggregate that they achieved until the compliance is confirmed. Thus, based on our understanding of their request of under-recovery of $ 350,507,771 and using the aggregate capacity factor achieved during the period of 32.5%, only 47.1 % should be granted or 32.5/69. This factor could be carried out similarly into other periods, if desired. This amount of under-recovery that should be denied is $ 165,089,160.

If this approach is used for the total under-recovery requested by the Companies through September 2022 of $430,484,411, then the amount to be denied would be (47.1%) or $202,758,157.

These costs do not include any penalties which the Commission could assess for failure to adhere to the Commission's Orders. Further, the disallowance factor of 52.9% (1-0.471) could also be utilized in future ENEC filings based on the higher priced coal contracts negotiated during the coal shortfall.

Summary of CTC Conclusions and Opinions

The facts are that the Companies did not meet the Commission orders to increase the capacity factors of these coal plants to the level of 69%. In addition, CTC did not see in the documentation provided by the Companies specific actions or programs which were set up to attempt to meet the Commission's requirements now or in the future.

Steps such as setting up technical task forces to evaluate how the plants could get to the level of capacity factors the Commission had established were not implemented.

CTC did not see that new creative concepts to obtain lower cost coal were utilized when the Companies made the decision to request the permission from the Commission to retrofit the units to meet the EPA requirements (last quarter of 2020) when the opportunity was there to take some actions.

In addition, while the Companies' intent may have been to keep these coal units operating through their end of life (2040), CTC did not see documentation about actions being discussed or taken to assure a competitive coal supply to these plants which is the critical ingredient for their dispatching by PJM. Without a competitive coal supply these plants would not be dispatched by PJM and therefore they would not run.

The above issues combined with the Companies' dependence on PJM and the underlying corporate support of ESG principles resulted in the scenario which ultimately developed: <u>the Companies did not have the coal from West Virginia for their coal plants in West Virginia.</u>

The conclusion which can be arrived at is the West Virginia ratepayer was paying for coal units which were not going to be dispatched, because of the cost of the fuel and its availability, while at the same time environmental retrofits have been approved and rates further increased to cover these costs.

CTC's opinion is that the Companies did not appear to exercise common sense and prudency in their decisions to fulfill "their obligation to serve their customers" with economic, safe, resilient and reliable electricity based on the use of the coal plants as established by the Commission.

It should be noted that by the coal plants not achieving the 69 percent capacity factor ordered by the Commission, the Commission has made it clear that the burden would be on the Companies to demonstrate that their actions that affected net ENEC costs were prudent and that the resulting net ENEC costs were reasonable and should be included in rates.

CTC did not see actions or steps that were taken by the Companies which would be a demonstration of their prudence in the decisions taken such as:

(1)maintaining adequate economical fuel supplies;
(2)keeping plants available for generation the maximum amount of time;
(3)maximum reduction, in accordance with good engineering and operating practices; of outage times related to maintenance, repairs, equipment modifications, site modifications, or other reasons; and
(4)effectively bidding to clear the PJM energy market considering the possibility of some negative hourly net margins that were necessary to maximize ensuing positive hourly net margins. This last step was not seen in the bidding processes presented by the Companies in the two Cases.

Appendix A -Timeline

Appalachian Power Company and Wheeling Power Company
Timeline of the Prudency Review
Case No. 20-1012-E-P
Case No. 20-1040-E-CN
Case No. 21-0339-E-ENEC
Case No. 22-0393-E-ENEC

November 5, 2020

- AEP News release.

December 14, 2020

- Case No. 20-1012-E-P New Case Filing Received.

December 23, 2020

- Case No. 20-1040-E-CN New Case Filing Received.

January 7, 2021

- Case No. 20-1040-E-CN Revised Testimony of Christian T. Beam and James F. Martin, filed by Counsel

March 26, 2021

- Case No. 20-1012-E-P Class Cost of Service Study and Supplemental Direct Testimony of Walsh, filed by APCo/WPCo

April 9, 2021

- Case No. 20-1012-E-P Revised Supplemental Direct Testimony of Walsh, filed by APCo/WPCo

April 16, 2021

- Case No. 21-0339-E-ENEC New Case Filing Received.

May 6, 2021

- Case No. 20-1012-E-P Direct Testimony WVEUG Staff Kanawha County Commission

- **Case No. 20-1040-E-CN Direct Testimony** WVCAG/SUN/EEWV (O'Leary) WVCAG/SUN/EEWV (Wilson) West Virginia Coal Association Sierra Club WVEUG Staff CAD

May 20, 2021
- **Case No. 20-1040-E-CN Rebuttal Testimony** CAG/SUN/EEWV (O'Leary) CAG/SUN/EEWV (Wilson) Sierra Club West Virginia Coal Association APCo/WPCo
- **Case No. 20-1040-E-CN** Supplemental Direct Testimony of Geoffery M. Cooke, filed by Staff

May 21, 2021
- **Case No. 20-1012-E-P Rebuttal Testimony** APCo/WPCo
- **Case No. 20-1012-E-P** Supplemental Direct Testimony of Geoffery M. Cooke, filed by Staff

June 3, 2021
- **Case No. 20-1012-E-P Evidentiary Hearing** Transcript Exhibits

June 8, 2021
- **Case No. 20-1040-E-CN Day One of Evidentiary Hearing** Transcript Exhibits

June 9, 2021
- **Case No. 20-1040-E-CN Day Two of Evidentiary Hearing** Transcript Exhibits (Part One) Exhibits (Part Two)

June 30, 2021
- **Case No. 20-1012-E-P** Commission Order conditionally approves a Modified Rate Base Cost Surcharge with future required updates and reviews.

July 7, 2021
- **Case No. 21-0339-E-ENEC Direct Testimony** CAD WVEUG Staff

July 21, 2021
- **Case No. 21-0339-E-ENEC Rebuttal Testimony** APCo/WPCo

July 30, 2021
- **Case No. 21-0339-E-ENEC Evidentiary Hearing** Transcript Exhibits

August 4, 2021

- **Case No. 20-1040-E-CN** Commission Final Order that Appalachian Power Company and Wheeling Power Company are granted a certificate of convenience and necessity to make the necessary compliance modifications to the Plants under Alternative 1 that will enable the three Plants to continue to generate electricity through 2040; that Appalachian Power Company and Wheeling Power Company are authorized to implement a surcharge effective for all service rendered on and after 09/1/2021; etc.

August 6, 2021

- **Case No. 20-1012-E-P** Commission Procedural Order that in addition to the exceptions set forth in the 6/30/2021 Commission Order, the prohibition on the filing of a base rate will be waived if: The Commission determines that the Companies' ability, on a combined basis, to meet their public service obligations is significantly impaired by events beyond their control.

August 30, 2021

- **Case No. 20-1012-E-P** Commission Final Order that because the Companies satisfied the condition for approval by agreeing not to file a base rate case until at least 06/30/2024, the MRBC tracker surcharge of $44,160,256, as discussed in the June 30 and August 6, 2021 Commission Orders, is approved and the rates approved in those orders go into effect for services rendered on or after 09/01/2021. Case Final.

September 1, 2021

- **Case No. 20-1012-E-P** Modified Rate Base Cost Surcharge (MRBCS) takes effect.
- **Case No. 20-1040-E-CN** Environmental Compliance Surcharge (ECS) takes effect

CRITICAL TECHNOLOGIES CONSULTING

September 2, 2021

- Case No. 21-0339-E-ENEC Commission Final Order that the rates approved in this Order for ENEC under-recovery and COVID-19 pandemic deferred expenses will be in effect for all services rendered on and after September 2, 2021; that Appalachian Power Company and Wheeling Power Company shall file monthly reports as closed entries in this case reporting net generation from all APCo and WPCo power plants by month, retail and wholesale energy load by month, and purchased power energy purchases by month and supplier. The reports shall also report purchased power demand and energy costs by month and supplier. Case Final.
- Case No. 21-0339-E-ENEC New ENEC rates take effect

September 2, 2021, Case No. 21-0339-E-ENEC Commission Final Order that the rates approved in this Order for ENEC under-recovery and COVID-19 pandemic deferred expenses will be in effect for all services rendered on and after September 2, 2021; that Appalachian Power Company and Wheeling Power Company shall file monthly reports as closed entries in this case reporting net generation from all APCo and WPCo power plants by month, retail and wholesale energy load by month, and purchased power energy purchases by month and supplier. The reports shall also report purchased power demand and energy costs by month and supplier. Case Final, and Case No. 21-0339-E-ENEC New ENEC rates take effect.

In the Conclusions of Law section of this order, it clearly points out the requirements of the WVPSC:

"CONCLUSIONS OF LAW"

- The Commission should allow the Companies to recover their proposed ENEC under-recovery balance as requested in this case, less $221,318.
- The Companies should be allowed to collect an additional $2,299,383 in deferred COVID-19 expenses in this case. If cost-savings are realized to offset these expenses, those cost-savings should be addressed in a future rate proceeding.
- The Companies should not be allowed to change, in this case, the rate development for certain Special Contract Customers, as identified above.

- Because projected ENEC costs include a utilization of West Virginia power plants at capacity factors of 49.6 percent for Amos, 57.3 percent for Mountaineer, and 34.7 percent for Mitchell and total purchased power is projected to be $35.44 per megawatt hour, the Companies' capacity factor projections are too low. The capacity factor for the three plants should be 69 percent in this case with the potential for an increased capacity factor as described in this Order.

- Based on the adjusted projected ENEC costs as described in this Order, the Companies' projected West Virginia jurisdictional ENEC is reduced by $66,681,445.

- The confidential information filed in Cos. Exhs. JCD-D1, JCD-D3, and MJZ-D1 and the confidential testimony of CAD witness Emily S. Medine should remain under seal for a period of five years."

September 8, 2021
- Case No. 20-1040-E-CN Petition to Reopen and Take Further Action; and Supplemental Direct Testimonies of Randall R. Short and Gary O. Spitznogle, filed by Counsel for APCo and WPCo

September 9, 2021
- Case No. 20-1040-E-CN Commission Procedural Order Reopening Case and Establishing Procedural Schedule

September 24, 2021
- Case No. 20-1040-E-CN Evidentiary Hearing Transcript Exhibits

October 12, 2021
- Case No. 20-1040-E-CN Commission Final Order granting Appalachian Power Company and Wheeling Power Company a certificate of convenience and necessity; that the Companies proceed with construction and take whatever steps are necessary to alert the EPA and WVDEP that it will proceed with environmental compliance work; that the Companies proceed with the ELG projects at all three plants, including the Mitchell Plant

March 2, 2022

- **Case No. 21-0339-E-ENEC** Commission Procedural Order that this proceeding is reopened for further review of information and possible further rate modifications as described herein; that the Companies will file the information described in this Order on or before March 14, 2022; that all parties to this proceeding may file comments on the information provided by the Companies on or before March 21, 2022; that the ENEC revenue requirement for the Companies will increase by $31.4 million to reflect a recalculation by the Commission of WPCo's reduced purchased power costs and additional fuel handling costs
- **Case No. 21-0339-E-ENEC** Commission-modified ENEC rates take effect

March 14, 2022

- **Case No. 21-0339-E-ENEC** APCo/WPCo Direct Testimony

March 21, 2022

- **Case No. 21-0339-E-ENEC Responses to Companies' March 14, 2022 Direct Testimony** CAD (Comments) CAD (Medine Supplemental Direct Testimony) WVEUG Staff

March 23, 2022

- **Case No. 21-0339-E-ENEC Evidentiary Hearing** Transcript

April 19, 2022

- **Case No. 22-0393-E-ENEC** New Case Filing Received.

May 13, 2022

- **Case No. 21-0339-E-ENEC** Commission Procedural Order that the rates approved in this Order will be effective for all services rendered on and after the date of this Order; that the Commission Staff shall conduct a review, as further described within the Order, of the Companies' generation plant availability and utilization and ENEC costs.
- **Case No. 21-0339-E-ENEC** ENEC rates take effect.

July 14, 2022

- **Case No. 20-1040-E-CN** Commission Final Order Denying Petitions for Reconsideration filed by CAD and CAG/SUN/EEWV

CRITICAL TECHNOLOGIES CONSULTING

August 1, 2022

- **Case No. 21-0339-E-ENEC** Final Order closing case.

August 31, 2022

- **Case No. 22-0393-E-ENEC** Supplemental Direct Testimony of John J. Scalzo, filed by APCo/WPCo

September 9, 2022

- **Case No. 22-0393-E-ENEC Direct Testimony** WVEUG Staff CAD (Smith) CAD (Medine)

September 23, 2022

- **Case No. 22-0393-E-ENEC Rebuttal Testimony** APCo/WPCo CAD (Smith) CAD (Medine)

October 4, 2022

- **Case No. 22-0393-E-ENEC Evidentiary Hearing Day One** Transcript Exhibits

October 5, 2022

- **Case No. 22-0393-E-ENEC Evidentiary Hearing Day Two** Transcript

February 3, 2023

- **Case No. 22-0393-E-ENEC** Final Order that the request of Appalachian Power Company and Wheeling Power Company to increase ENEC rates by $297 million is denied, etc.

PUBLIC VERSION

CRITICAL
TECHNOLOGIES
CONSULTING

Appalachian Power Company and Wheeling Power Company
Supplement to the Timeline of the Prudency Review
Case No. 20-1012-E-P
Case No. 20-1040-E-CN
Case No. 21-0339-E-ENEC
Case No. 22-0393-E-ENEC

Case No. 20-1012-E-P Petition for Implementation of an Experimental Infrastructure Investment Tracker and Surcharge

- Case Filing: December 14, 2020
- Direct Testimony: May 6, 2021
- Rebuttal Testimony: May 21, 2021
- Evidentiary Hearing: June 3, 2021
- Final Order: August 30, 2021
- Rates Effective: September 1, 2021

Case No. 20-1040-E-CN Application for a certificate of public convenience and necessity for the internal modifications at coal fired generating plants necessary to comply with federal environmental regulations

- Case Filing: December 23, 2020
- Direct Testimony: May 6, 2021
- Rebuttal Testimony: May 20, 2021
- Evidentiary Hearing: June 8 and 9, 2021
- Final Order: August 4, 2021
- Rates Effective: September 1, 2021
- Case Reopen: September 9, 2021
- Evidentiary Hearing upon Reopen: September 24, 2021
- Final Order upon Reopen: October 12, 2021
- Final Order denying Exceptions: July 14, 2022

Case No. 21-0339-E-ENEC Petition to initiate the annual review and to update the ENEC rates currently in effect.

- Case Filing: April 16, 2021
- Direct Testimony: July 7, 2021
- Rebuttal Testimony: July 21, 2021
- Evidentiary Hearing: July 30, 2021
- Final Order: September 2, 2021

- Rates Effective: September 2, 2021
- Case Reopen: March 2, 2022
- Interim Rates Effective: March 2, 2022
- Company Direct Testimony upon Reopen: March 14, 2022
- Responses to Company Direct Testimony: March 22, 2022
- Evidentiary Hearing upon Reopen: March 23, 2022
- Order Approving Rates and Prudency Review: May 13, 2022
- Rates Effective: May 13, 2022
- Final Order: August 1, 2022

Case No. 22-0393-E-ENEC Petition to Initiate the Annual Review and to Update the ENEC Rates Currently in Effect

- Case Filing: April 19, 2022
- Direct Testimony: September 9, 2022
- Rebuttal Testimony: September 23, 2022
- Evidentiary Hearing: October 4 and 5, 2022
- Final Order: February 3, 2023

CERTIFICATE OF SERVICE

CASE NO. 21-0339-E-ENEC

CASE NO. 22-0393-E-ENEC

**PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON**

**CASE NO. 21-0339-E-ENEC
APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY**

**CASE NO. 22-0393-E-ENEC
APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY**

CERTIFICATE OF SERVICE

I, LUCAS R. HEAD, Counsel for the Public Service Commission of West Virginia, do hereby certify that a copy of the foregoing report has been served upon the following parties of record by electronic mail this 28th day of April, 2023.

William C. Porth, Esq.
Counsel, Appalachian Power Company
Robinson & McElwee PLLC
PO Box 1791
Charleston, WV 25326
wcp@ramlaw.com

Anne C. Blankenship, Esq.
Counsel, Appalachian Power Company
Robinson & McElwee
PO Box 1791
Charleston, WV 25326
acb@ramlaw.com

Heather B. Osborn, Esq.
Consumer Advocate Division
300 Capitol Street
Suite 810
Charleston, WV 25301
hosborn@cad.state.wv.us

Robert F. Williams, Esq.
Director
Consumer Advocate Division
300 Capitol Street, Ste. 810
Charleston, WV 25301
rwilliams@cad.state.wv.us

John Auville, Esq.
Consumer Advocate Division
300 Capitol Street, Ste. 810
Charleston, WV 25301
jauville@cad.state.wv.us

Derrick P. Williamson, Esq.
Counsel, WVEUG
Spilman Thomas & Battle, PLLC
1100 Bent Creek Blvd., Suite 101
Mechanicsburg, PA 17050
dwilliamson@spilmanlaw.com

Barry A. Naum, Esq.
Counsel, WVEUG
Spilman Thomas & Battle, PLLC
1100 Bent Creek Boulevard, Suite 101
Mechanicsburg, PA 17050
bnaum@spilmanlaw.com

Susan J. Riggs, Esq.
Counsel, WVEUG
Spilman Thomas & Battle
PO Box 273
Charleston, WV 25321-0273
sriggs@spilmanlaw.com

Keith D. Fisher, Esq.
Senior Counsel
Appalachian Power Company
500 Lee Street East, Suite 800
Charleston, WV 25301
kdfisher@aep.com

Steven W. Lee, Esq.
Counsel, WVEUG
Spilman Thomas & Battle, PLLC
1100 Bent Creek Boulevard, Suite 101
Mechanicsburg, PA 17050
slee@spilmanlaw.com

H. Brann Altmeyer, Esq.
Counsel, for West Virginia Coal Association, Inc.
61 Fourteenth Street
Wheeling, WV 26003
brannaltmeyer@pgka.com

Jacob C. Altmeyer, Esq.
Counsel, for West Virginia Coal Association, Inc.
61 Fourteenth Street
Wheeling, WV 26003
jacobaltmeyer@pgka.com

Charles K. Gould, Esq.
Counsel, Steel of West Virginia, Inc.
Jenkins Fenstermaker PLLC
325 8th Street, 2nd floor
Huntington, WV 25701
ckg@jenkinsfenstermaker.com

Thomas E. Scarr, Esq.
Counsel, Steel of West Virginia, Inc.
Jenkins Fenstermaker PLLC
325 8th Street, 2nd floor
Huntington, WV 25701
tes@jenkinsfenstermaker.com

Al Ferrer
Consultant, Staff
Critical Technologies Consulting
al.ferrer@crittech.com

Benson Hill
Consultant, Staff
Critical Technologies Consulting
Ben.Hill@crittech.com

Lucas R. Head
Staff Attorney
WV State Bar I.D. No. 11146