BEFORE THE
WEST VIRGINIA PUBLIC SERVICE COMMISSION

IN THE MATTER OF WEST VIRGINIA TASK FORCE TO ASSURE DEPENDABLE AND AFFORDABLE ELECTRIC SUPPLY

PUBLIC COMMENTS OF RMI

April 27, 2023
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Summary

In April 2022, the West Virginia coal association (WVCA) requested to initiate a task force to examine issues related to fuel supply that are preventing the state's regulated electric utilities (Appalachian Power Company, Wheeling Power, Monongahela Power Company, and the Potomac Edison Company) from complying with the commission directive to operate the coal fleet at a 69 percent capacity factor. The commission believes that operating in-state coal plants at a minimum 69 percent capacity factor provides the most benefit to ratepayers. On June 16, 2022, in response to the WVCA request, the commission approved the formation of a task force of stakeholders to “investigate ways to decrease energy costs for West Virginia electric utility customers,” currently referred to as “the task force to assure dependable and affordable electric supply.”

The unprecedented economic realities of the past few years, driven in part by the global coronavirus pandemic and Russia’s invasion of Ukraine, have undoubtedly put pressure on electric utilities and fuel suppliers to ensure that they procure safe, affordable, and dependable power for ratepayers, as evidenced by the numerous proceedings in front of this commission. Indeed, energy affordability is a key challenge in West Virginia that requires new solutions.

However, increasing utilization of the state's coal plants is only likely to result in additional cost and risk for burdened ratepayers. Our analysis offered in these comments

1 See generally West Virginia Public Service Commission Case No. 21-0658-E-ENEC and Case No. 21-0339-E-ENEC.
demonstrates that enforcing a directive to operate the West Virginian coal plants at a minimum 69 percent capacity factor and changing long-term fuel procurement strategies from West Virginia utilities to achieve that directive, can only be accomplished by locking into high price coal contracts and through uneconomic self-scheduling of coal plants into the PJM market. Historically, the utilities' regulated coal fleet has not been able to economically operate at 69 percent factors consistently. Mandating a specific capacity factor that various coal-fired generators would be required to meet regardless of economics exposes West Virginia ratepayers to the operating losses that will inevitably occur and deprives them of the cost saving benefits that result from committing and dispatching generation resources based on economics. Requiring utilities to operate at uneconomic levels in the future will not only place a direct undue burden on utilities and ratepayers, but it will also lead to reduced grid reliability and inhibit future energy development in the state.

This task force is officially charged with evaluating ways to make energy more affordable for customers. The WVCA's suggested solutions are not supported by a more complete analysis of data over the last few years, rather than the small subset of cherry-picked data from 2021 that WVCA offered as evidence. The commission should not make a decision that could lock ratepayers into costly change to fuel procurement and generation strategies without carefully considering this. Doing so has the potential to create serious long-lasting consequences for ratepayers and for the grid – consequences that work in opposition to the commission's goal of assuring a dependable and affordable electricity supply.
Before any long-term changes are implemented to the fuel procurement and operation strategy of electric utilities, the commission should thoroughly analyze the consequences that such changes will have on ratepayer bills and electric system reliability. The commission should further consider the message that such fuel and power procurement changes will send regarding long-term energy development in the state—development that could otherwise meaningfully reduce residential energy bills. Those consequences should be weighed against any specious benefits of increased generation at local coal plants with restrictive and expensive long-term fuel contracts, as favored by WVCA.

West Virginians need fresh solutions to address affordability

In creating this task force, the Commission has shown a commendable focus on affordability. There is an energy affordability crisis across the United States, and this crisis is particularly acute in West Virginia. There was an affordability crisis in West Virginia prior to the past few years, and that crisis has been exacerbated with recent coal and gas prices producing huge spikes in electricity prices.

Current state of energy affordability in West Virginia

Hundreds of thousands of families across West Virginia spend a higher-than-normal share of their income on their energy.2 In 2021, the average monthly electric bill for a

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residential customer in West Virginia was $129.61, which is $8.60 higher than the national average ($121.01 per month). Energy burden, the percent of a family's income spent on energy, in West Virginia is on average 6.46 percent, which is higher than the national average of 5.2 percent.

The start inequities of energy burden are starker when broken down by income bracket (summarized in Table 1). Households classified as *extremely low-income* (with a household income between zero and 100 percent of the federal poverty level) in West Virginia have an average energy burden of 19 percent. 118,380 out of nearly 730,000 households in West Virginia hold this extremely low-income classification. Households identified as *very low-income* (with a household income between 100 percent and 200 percent of the federal poverty level) in West Virginia have an average energy burden of 7.6 percent. Energy affordability researchers have found that households with an energy burden between 4 percent and -7 percent as are categorized as *energy stressed*, between 7 percent and 10 percent as *energy burdened*, and burden over 10 percent as *energy impoverished*. Given these definitions, at least 279,220 households in West Virginia are already energy burdened or energy impoverished.

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Impacts to West Virginia households

Data also demonstrates how energy burden impacts West Virginia households. According to data from the US Census Bureau’s household pulse survey, thousands of households in West Virginia are being forced to make difficult decisions due to their high energy burdens. In the past year, 30 percent of households in the state reported reducing or forgoing expenses for basic household necessities, such as medicine or food, for at least one month in order to pay an energy bill. The health and safety risk this poses to families is further aggravated by how the energy burden can impact decision-making on internal heating and cooling. In West Virginia, 16 percent of households reported keeping their homes at a temperature that felt unsafe or unhealthy for at least one month in the past year. Lastly, nearly 331,000 households in West Virginia, about 24 percent of the entire state population, reported being unable to pay their energy bill or unable to pay the full bill.

Table 1. Average Energy Burden in West Virginia Across Income Levels

<table>
<thead>
<tr>
<th>Group</th>
<th>Average Energy Burden (%)</th>
<th>Number of households</th>
</tr>
</thead>
<tbody>
<tr>
<td>All households in West Virginia</td>
<td>6.46%</td>
<td>730,000</td>
</tr>
<tr>
<td>Extremely low-income (0-100% FPL)</td>
<td>19%</td>
<td>118,380</td>
</tr>
<tr>
<td>Very low-income (100-200% FPL)</td>
<td>7.6%</td>
<td></td>
</tr>
</tbody>
</table>

amount. Thus, almost a quarter of all households in the state are vulnerable to shutoffs and arrearages due to an inability to make energy bill payments.

For three out of the four regulated utilities in West Virginia (Appalachian Power Company, Wheeling Power, Monongahela Power Company), costs associated with coal-fired power plants make up the largest portion of customers’ energy bills. This reliance on coal makes energy bills sensitive to fluctuations in coal prices. Running and maintaining coal-fired power plants makes up a significant share of household energy expenditures, around 20-50 percent, see Table 2 for details. This reliance on coal means that as coal prices rise, as they have since 2019, the energy burden will also rise. Extremely low-income customers will be most impacted when prices rise – and extremely low-income customers served by all four regulated utilities are all considered energy impoverished as their energy burdens are all over 10 percent, with a state average at 19 percent (see Table 1 and Table 2). Table 2 summarizes both the state of energy burden and the role of coal in the energy bills of West Virginians in 2020 for each of the state’s four regulated electric utilities.7

7 RMI Utility Transition Hub, https://utilitytransitionhub.rmi.org/
Table 2. Table of regulated West Virginia utilities and energy burden

<table>
<thead>
<tr>
<th>Regulated utility</th>
<th>Average energy burden for all customers</th>
<th>Average energy burden for extremely low-income customers (0-30% area median income)</th>
<th>Percent of electric bill associated with costs of coal plants</th>
</tr>
</thead>
<tbody>
<tr>
<td>Appalachian Power Company</td>
<td>2.36%</td>
<td>13.8%</td>
<td>39.7%</td>
</tr>
<tr>
<td>Wheeling Power</td>
<td>2.36%</td>
<td>19.5%</td>
<td>48.0%</td>
</tr>
<tr>
<td>Monongahela Power Company</td>
<td>2.89%</td>
<td>16.5%</td>
<td>49.5%</td>
</tr>
<tr>
<td>The Potomac Edison Company</td>
<td>1.26%</td>
<td>11.6%</td>
<td>20.7%</td>
</tr>
</tbody>
</table>


The data presented here validate the need for this task force to prioritize delivering the most affordable energy to West Virginia customers.

A 69% minimum capacity factor would lead to increased energy costs.

Based on analysis of historical data, increasing coal capacity factors will not lead to more affordable energy for West Virginians. Coal units that operate at 69 percent capacity factors but cannot do so economically without displacing lower cost available resources, will be driving up the cost of electricity for ratepayers.

Economic dispatch limits uneconomic spending

The commission has asserted in its past orders that requiring West Virginia coal plants to operate at higher capacity factors will translate into consumer savings. This requirement would come into conflict with numerous energy market practices that ensure least-cost generation, most notably the practice of merit-order, or economic dispatch. In wholesale energy markets, including PJM where West Virginia coal plants operate,
resources are dispatched in order of lowest bid price, subject to grid constraints. Generation owners submit "cost offers" (bids) to provide energy to the grid in the day-ahead market, and grid operators then select the lowest-cost resources available to meet demand for every hour of the day, balancing fluctuations between predicted and actual demand with the real-time market (see Figure 1). The last-called resource is the resource that sets the market clearing price (in both the day-ahead and real-time markets), which is the price that all resources that generate get paid for generating.

Figure 1. Representational illustration of economic dispatch used by PJM.

Economic Dispatch

The bid that energy producers submit to grid operators in the energy market should reflect the short run, marginal cost (SRMC) of power production, which includes the cost of fuel and other operating expenses incurred while the plant is running (but excludes fixed
The auction structure motivates energy producers to submit bids that are true to the production cost of the plant. If a generator's bid into the market is higher than the true production cost, it runs the risk of not being called to operate, which creates no revenue for the generation owners. Conversely, if a generator's bid into the market is lower than the true production cost, it runs the risk of operating without recovering the full cost to operate, incurring losses that ultimately get passed through to ratepayers in the case of rate-regulated utilities, like those in West Virginia.

Grid operators use economic dispatch to ensure that the lowest-cost resources are being utilized to meet demand, and that utilities that follow economic dispatch are ensuring that ratepayers are paying for the lowest cost of available power. Resources that are available to operate, but that are not selected by the grid operator to run, are left offline because there are other less-expensive resources available to meet load. Market protocols also account for unit constraints like minimum up time, minimum down time, ramp rates, and long-lead time resources that take more than 24 hours to turn on. PJM, for example, conducts projections out beyond the 24-hour day-head market window and, if needed, will call on long-lead time resources (including coal) to turn on when conditions indicate they will be needed for reliability purposes.

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8 In PJM, the capacity market exists for generators to recover the fixed costs of their generating resources. Energy market revenues are primarily meant to be used to recover the variable operating expenses incurred through power production. While profits from the energy market can be used to pay off fixed costs, capacity market revenues in PJM are primarily designed for that purpose.

9 See PJM operating manuals 10 and 13.
like light switches. Power plants can be called on to run for hours — or even days — even when the market clearing price drops below the unit's cost offer. Economic dispatch of units still allows a power plant to run “uneconomically” for a few hours over the course of the day if that will keep overall system costs down. These units are also then available for “uplift” payments. Uplift payments are also known as “make whole” payments because they provide out of market payments to generate to make up any difference between operating costs and market revenues.

Power plant operators can effectively by-pass the merit order dispatch process through “self-scheduling.” Utilities that select to run their power plants when they are not needed for reliability and in place of less expensive available resources by self-scheduling their own resources are causing ratepayers to pay above market costs for their electricity, which ultimately raises ratepayers’ bills. “Self-scheduled” resources are not eligible for uplift payments and so if they operate at a loss, they must be made whole by captive customers.

Economics should be the driver of coal capacity factors

Our analysis using PJM data from 2019 through late 2021 shows that coal-fired power plants in West Virginia have not been economic to operate at a 69 percent capacity

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10 Economically committed units that are called on by the market to run but end up not recover their costs from Energy Market payments are eligible for “make whole payments” that pay power plants the difference between costs and market prices. Self-committed and self-scheduled resources are not eligible for make whole payments.

11 PJM defines a self-scheduled resource as “a generating resource that is turned on by the operating company and committed into the energy market by the operating company.”
factor on an annual basis. This result assumes the reported cost of coal that utilities paid during this period, and still holds true had utilities been able to procure additional coal at spot prices.

We defined a coal plant to be economic to operate when the SRMC per megawatt-hour of operating the plant was below the clearing price of the nearest market node. When the cost to operate the plant exceeded the revenue it earned from the energy market, it is considered uneconomic to operate. The SRMC is the sum of both fuel and variable operating and maintenance costs reported through EIA 923 and FERC Form 1, here compiled by S&P Global. The SRMC to operate the plant is what should set market cost offers. The cost of coal is typically the dominant contributor to variable operating costs and thus is a major factor that influences the bid generators submit for the day-ahead energy market. Typically, annualized coal fuel costs are reported to federal and state regulators, which we use here to determine the fuel portion of SRMC for each plant.

As an example of the results, figure 4 shows that the Harrison power plant has been persistently operating uneconomically by the above definition, beginning in early 2019 and through late 2021. Not only has this plant been unable consistently operate economically for 69% of each month on an hourly basis (thus unable to economically achieve a 69% capacity factor), it also was operating more than what was economically viable, based on its SRMC. Most egregiously, in April 2020 the plant operated during 63% of the month's hours, when based on its reported SRMC and market clearing prices, it was only economic to operate during 4% of the month's hours. In other words, in April 2020 it was cost-effective
and more economic to purchase power from the market for 96% of the month on an hourly basis, and yet the utility chose instead to operate this plant at some capacity in 63% of the month’s hours. The one period in which the Harrison power plant appeared to be operating less than what economic dispatch would suggest was during a short period of coal scarcity in 2021. This trend is true for most of the regulated coal-fired power plants in West Virginia (see appendix A for more details on the rest of the coal fleet).

*Figure 4. Historical economics of operating the Harrison power plant.*

<table>
<thead>
<tr>
<th>Harrison Power Plant Economics: 2019-2022</th>
</tr>
</thead>
<tbody>
<tr>
<td><img src="chart.png" alt="Chart showing economic operating hours" /></td>
</tr>
</tbody>
</table>

Values are the average fraction of hours per month that units at the plant were operated (weighted by unit capacity), and the fraction of hours per month that units at the plant were economic, based on both reported fuel costs and estimated fuel costs had utilities purchased coal at market prices.

Source: S&P Global

Beyond historically reported fuels costs, we estimated what the variable operating, and maintenance (VOM) costs each plant would have been if utilities had chosen—and been able—to procure additional coal at spot market prices in 2021 and 2022. From 2020 to 2021, annual average prompt quarter coal prices in the northern Appalachian and central Appalachian basins rose 29 and 16 percent, respectively. Furthermore, between June and December 2021, average prompt quarter coal prices in the northern Appalachian and
central Appalachian basins rose 43 and 27 percent, respectively, over average prompt quarter coal prices in the second half of 2020. These price increases are not necessarily reflected in fuel costs reported to federal and state regulators (specifically in EIA form 923 and FERC form 1) at each power plant because utilities chose not to procure additional fuel when prices rose.

Overall, when the cost of procuring coal at exorbitantly high spot market prices is incorporated into each plant's SRMC, the frequency of hours in which West Virginia's coal fleet could operate economically plummets (see Figure 4 and Appendix A). This is most obvious in 2022, when coal prices reached as high as $200 per ton. Based on released operations data for 2022, some of the power plants responded to the market signals and reduced their capacity factors. However, as long as coal prices remain at their record high levels, it will be increasingly unlikely for West Virginia's coal plants to economically operate at the high-capacity factors prescribed by the Commission. Thus, market prices and economics have been the limiting factor for plant operations and not fuel supply, as has been suggested in this docket. AEP has shown that economic and operational limitations have rightfully limited how frequently it operates their coal-fired power plants, and it has repeatedly asked the commission for clarification on whether running coal-fired units out-

\[\text{See Appendix A}\]
of-merit to achieve a 69 percent capacity factor, which "may very well result in increased
costs to customers," is more important than economic dispatch.\textsuperscript{13}

The WVCA, in its initial filing, selected the few brief periods in time in late 2021 in
which utilities may have been able to operate coal-fired plants slightly more frequently and
economically, an example of which is highlighted below. This range is not indicative of the
longer-term picture and is insufficient for making the argument that utilities should
operate plants at higher capacity factors. The WVCA did not address the historically poor
economics of these plants outside of this period nor record high prices of coal that currently
dominate the market that make operating these plants increasingly expensive.\textsuperscript{14} Selecting a
few months-long favorable window, while ignoring the years prior and months since, is
quintessential cherry-picking.

\textsuperscript{13} See "Testimony Of Jason M. Stegall and John J. Scalzo On Behalf Of Appalachian Power Company And Wheeling
Power Company Before The Public Service Commission Of West Virginia On Reopening In Case No. 22-0393-E-ENEC" (April 19, 2022), "TESTIMONY OF JOHN J. SCALZO ON BEHALF OF APPALACHIAN POWER COMPANY AND WHEELING
POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA ON REOPENING IN CASE NO. 21-
0339-E-ENEC" (March 14, 2022), and "Post-hearing Comments Of Appalachian Power Company And Wheeling

\textsuperscript{14} See West Virginia Coal Association’s petition in Case No. 22-0352-E-P.
Signal versus noise: long-term trends pose risk to coal’s competitiveness

Statisticians often talk about separating the noise from the signal. Fuel price volatility (and by extension market price volatility) is the noise; the signal is the long-term trend in the electric power sector, include declining prices of renewables and reduced reliance on coal for electricity. While there was a narrow window of a few months in 2021 when coal plants could have operated more if they had access to coal supplies, that window was brief and the conditions that created that window are both rare and no longer true. For example, one of the key factors making coal more economic during those months was high gas prices, but gas prices have already dropped back below $3.00/MMBtu, bringing an end
to the most recent price spike event. Several long-term trends translate into a clear signal that coal's economic competitiveness will continue to decline. Downward pressure on energy prices that will result from the scheduled addition of lower-cost resources to the PJM system, lower gas prices, and increasing regulatory pressure on coal-fired power plants all present as headwinds for coal-fired power.

Planned additions of renewables will create downward pressure on energy prices. At the end of 2021, the PJM interconnection queue had over 250 GW of resources in the queue (overwhelmingly zero-marginal-cost resources), which is more capacity than is needed to meet the current and foreseeable future system peak. While not all of these resources will be built, adding even a fraction of these resources will lower system-wide energy prices and make the cost of operating the coal fleet at high capacity factors even more economically challenging than it is currently, resulting in fewer and fewer hours when it is economic to dispatch coal plants. Continuing to operate coal plants at high-capacity factors even as more zero-cost resources are added to the grid would prevent ratepayers from taking advantage of the lower-marginal-cost resources available to them through the PJM market. This would ensure that West Virginia ratepayers will be paying more for their energy than

the least-cost available in the market, and more than other customers within the PJM region.

Longer coal contracts increase cost and risk for ratepayers.

The commission has expressed interest in analyzing ways to ensure affordable electric supply for its ratepayers and has directed the task force to analyze ways to do so, including by discussing the terms of coal supply contracts. The WVCA assumes in its petition that procuring more coal and having larger and longer coal contracts benefits ratepayers because it would enable utilities to operate their coal plants more frequently in the wholesale market. This claim makes numerous assumptions that are not supported by historical observations or long-term forecasts.

Directing utilities to sign long-term contracts for coal at a time when coal prices are at a high will not reduce costs for ratepayers. Prompt quarter coal prices have increased exponentially since the beginning of 2021, across both the central Appalachian and northern Appalachian basins, with average prompt quarter prices across all suppliers roughly quadrupling from the start of 2021 to the end of 2022 (see Figure 3). Coal costs that are two to four times higher than ten-year averages will increase the cost of operating the West Virginian coal fleet; meanwhile, the cost of operating other existing

\[17\] See West Virginia Coal Association's petition in Case No. 22-0352-E-P.
resources continues to decline, and the addition of low-cost carbon-free resources continues at its projected pace.\textsuperscript{18}

The WVCA petition does not address the additional long-term ratepayer costs and risk associated with signing long-term coal contracts in today's market. If utilities sign long-term contracts for coal at the rates seen today, in the attempt to be able to save money through improved plant efficiency, they will lock ratepayers into paying for coal at inflated rates. This is why there has been a trend of shorter and shorter coal contracts.\textsuperscript{19}


Additionally, fuel contract structures used in larger and longer coal procurements can result in additional costs such as take-or-pay fees or sunk costs from over-procurement that add to ratepayer burden. Long-term fuel contracts typically have take-or-pay clauses that require off-takers to purchase a certain amount of fuel each month or pay a fee if fuel is not needed. When utilities sign long-term fuel contracts, they lock ratepayers in to paying for them at a contracted price for the duration of the contract (unless an exit clause is provided), even if the fuel is no longer needed. Signing larger and longer coal procurement contracts at today's rates creates substantial risk for ratepayers, putting them on the hook for higher-than-long-term average coal costs that they would pay even when coal from the contract may no longer be needed or in ratepayers' best interest.

Current coal prices and the inflexibility of long-term contract structures will increase the cost to operate the West Virginia coal fleet, prevent ratepayers from utilizing
lower-cost power from the market, and commit ratepayers to pick up the bill and bear the risk of these decisions. The WVCA’s proposal for stronger contract terms stands to benefit its members and coal suppliers at the expense of ratepayers and even West Virginia’s electric utilities. If utilities lock in contracts today, at historical high prices, coal producers stand to make windfall profits for decades while ratepayers bear the cost and risk through unaffordable electric bills.

Utility forecasting is not to blame for broader supply constraints

The WVCA attributes the inability of its coal suppliers to procure enough supply to meet demand when it was needed to utilities and their forecasting methods. While utility forecasting methods may have been challenged by recent unprecedented global events, including the coronavirus pandemic and Russia’s invasion of Ukraine, uncertainty around these unpredictable events alone is not indicative of systemic forecasting problems.

What the WVCA sees as inaccurate forecasting by utilities could also be considered prudent utility spending. Utilities should exert caution around spending additional ratepayer funds on fuel, especially during periods of elevated fuel prices and price uncertainty. Over-procurement of fuel is costly for ratepayers and creates the financial risk of a disallowance of those costs by the commission if they find such spending was imprudent. Hesitancy around spending of ratepayer funds should be encouraged, to ensure that the costs and risks of options are adequately considered. Increasing long-term fuel expenditures to solve an impermanent, short-term reality is likely not the least-cost, least-risk option for maintaining an affordable, adequate energy supply.
Broader challenges with domestic coal supply also contributed to supply limitations. The WVCA itself indicated in its initial filing with the commission that “available domestic coal supplies are constrained for a variety of reasons and production has not responded to increased demand,” admitting that when utilities did want to procure additional fuel supplies, it was “too late to secure the coal necessary” to supply their plants. These are constraints impacting fuel suppliers themselves, exacerbated over the past year by the coronavirus pandemic and international demand for coal exports. These constraints are beyond the scope of utility forecasting alone.

A 69% capacity factor mandate will reduce reliability.

Enforcing a minimum capacity factor for West Virginia coal plants could reduce system reliability. Forcing older steam units to run at higher frequency could cause additional wear and tear on the coal plants, potentially resulting in forced outages and increasing the risk of unexpected reliability events.

Increased risk of forced outages

Hitting the 69 percent capacity factor at a given plant could result in increased wear and tear on the boiler and associated parts of the power plant. This wear and tear will translate into increased maintenance costs and will also increase the risk that the power

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20 See West Virginia Coal Association's petition in Case No. 22-0352-E-P.
plant will have a forced outage. Forced outages are outage events (either full or partial) that cannot be reasonably delayed beyond 48 hours. According to PJM, fossil steam plants, which include all coal plants and a few gas and oil steam generators, have high forced outage rates. Fossil steam forced outage rates are four times larger than the forced outage rates of gas combined cycle power plants, roughly twice that of hydro power, and over ten times that of nuclear power plants. Large fossil steam plants have the second highest forced outage rate of any power plant type, behind very small combustion turbines. Large power plant outages are more challenging for grid operators to address than small power plant outage, because there is more energy and capacity that needs to be replaced (e.g. 50 MW for a small combustion turbine versus 500 mw for a large steam fossil plant).

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Table 3 PJM 2017 - 2021 Weighted Equivalent Forced Outage Rate (WEFOR) by fuel type

<table>
<thead>
<tr>
<th>Unit type</th>
<th>Rating (MW)</th>
<th>WEFOR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fossil - steam</td>
<td>All</td>
<td>13.6</td>
</tr>
<tr>
<td></td>
<td>0-199</td>
<td>13.3</td>
</tr>
<tr>
<td></td>
<td>200-799</td>
<td>12.8</td>
</tr>
<tr>
<td></td>
<td>800+</td>
<td>15.6</td>
</tr>
<tr>
<td>Nuclear</td>
<td>All</td>
<td>0.9</td>
</tr>
<tr>
<td>Combustion turbine</td>
<td>All</td>
<td>5.8</td>
</tr>
<tr>
<td></td>
<td>0-19</td>
<td>18.6</td>
</tr>
<tr>
<td></td>
<td>20-29</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>50 +</td>
<td>4.5</td>
</tr>
<tr>
<td>Cc</td>
<td>All</td>
<td>3.6</td>
</tr>
<tr>
<td>Hydro</td>
<td>All</td>
<td>7.4</td>
</tr>
<tr>
<td>Pumped hydro</td>
<td>All</td>
<td>4.1</td>
</tr>
</tbody>
</table>

In order to achieve the 69% capacity factor target, utilities might have to (a) leave coal plants on for longer periods of time and cycle the output up and down to meet demand; or (b) turn the coal plant on and off more frequently to capture times when it makes most economic sense to run the coal plant. Both will result in “cycling costs” and additional wear and tear to the power plant parts. NREL has found:

Cycling refers to the operation of electric generating units at varying load levels, including on/off, load following, and minimum load operation, in response to changes in system load requirements. Every time a power plant is turned off and on, the boiler, steam lines, turbine, and auxiliary components go through unavoidably large thermal and pressure stresses, which cause damage... while cycling-related increases in failure rates may not be noted immediately, critical components will eventually start to fail. Shorter component life expectancies will result in higher plant equivalent forced outage rates (EFOR) and/or higher capital and maintenance costs to replace...
components at or near the end of their service lives. In addition, it may result in reduced overall plant life.\textsuperscript{24}

Market observers in Texas have identified and tracked data to validate this risk of increased forced outages. In an attempt to increase reliability, policy makers approved a new process for Reliability Unit Commitment (RUC). Unfortunately, this has proved to be an expensive endeavor with a number of unintended consequences.\textsuperscript{25} The companies operating these power plants have raised concerns that the new procedures forcing higher capacity factors are causing accelerated wear and tear on steam power plants. These owners predicted the RUC process would result in unexpected outages.\textsuperscript{26} Unfortunately, those predications came to fruition; Texas has experienced increased forced outages of thermal units, particularly coal and gas steam units as a result of the RUC process.\textsuperscript{27} According to the ERCOT market monitor, “Short-term forced outages and deratings spiked in February during Winter Storm Uri which led to more long-term outages in the following months to perform repairs.”\textsuperscript{28}

A greater probability of forced outages at large steam fossil plants creates more risk for grid operators. Fossil fuel resources, in contrast with renewable resources that are

\begin{itemize}
\item \textsuperscript{25}https://rmi.org/the-solution-to-grid-reliability-go-bigger-and-bolder-on-renewables-and-energy-storage/
\item \textsuperscript{26}https://www.houstonchronicle.com/business/energy/article/ERCOT-shift-in-operations-may-mean-rise-in-prices-17281676.php?utm_medium=email
\end{itemize}
predictably variable (e.g. a grid operator can plan for the sun to set at a specific time), often have *unexpected* outages, which pose a greater risk to the grid because it is very difficult to predict when a critical component might break at a gas or coal power plant. Preparing for an unexpected, forced outage is much more of a challenge.

The impact of increasing forced outages can be severe. The impact of increasing forced outages can be severe. In Texas in 2021 and in California in 2020, fossil fuel infrastructure forced outages were the proximal cause of major customer power outages, resulting from cold- and heat-related failures. In Texas, 40 percent of coal and gas plants were offline due to equipment failures or fuel supply issues, i.e., forced outages, at the height of the crisis. In the mid-Atlantic, a study recently showed that PJM’s current methods put it at risk of overestimating the share of fossil power that will be available in extreme conditions by as much as 20 percent.

The unpredictability of fossil fuel power assets stands in stark contrast to more predictable renewables like wind and solar, as well as the emerging capabilities of battery storage and other advanced technologies. Australia is a leader in using renewables, storage,
and technologies like demand flexibility to support system reliability. The grid operator in Australia has been successfully using batteries to store solar power during the day and provide valuable energy as the sun sets but temperatures remain high, avoiding blackouts even as demand soars. Batteries in Australia not only provide energy and capacity during acute reliability events, but they also provide a range of ancillary services that keep the grid stable during all hours of the year.

A 69% capacity factor mandate could hinder development of other energy projects. Choosing to uneconomically dispatch in-state coal generators into the wholesale market (via self-commitment of owned resources) negatively impacts market prices and local energy development.

Self-commitment of resources that would not otherwise be economically dispatched into the wholesale market has been shown to suppress wholesale energy market prices in RTOs without passing along the benefits of lower wholesale prices. The practices results in reducing and sometimes eliminating the revenue other dispatched generators earn (figure 5). As higher-cost resources self-commit and operate in place of lower-cost resources, the ultimate market clearing price ends up being lower than what it would be if each resource was dispatched economically. The price suppression effect that results from uneconomically

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self-scheduling resources has been observed in wholesale markets across the country, with rates of price suppression ranging from 2.4 percent to as high as 30 percent.\textsuperscript{35}

Price suppression erodes revenues for lower-cost generation. When higher-cost marginal resources self-commit they skip to the front of the line and displace lower cost resources, which means that they won't earn revenue.

The suppressed wholesale prices, however, do not translate into retail cost savings. This is because the coal generators and fuel have been approved for cost recovery, West Virginia ratepayers still pay the full costs to run the coal plants in their bills. So, if a coal plant displaces a cheaper resource in the bid stack, wholesale prices decrease but counterintuitively retail prices increase.\textsuperscript{36}


Price suppression could chill financial prospects of building new energy resources in West Virginia. Developers looking to build lower-cost energy resources are less inclined to do so in locations where they are unlikely to operate or market prices, and corresponding
project revenues, are artificially suppressed. As a result, self-commitment of coal resources to achieve the 69 percent target has the potential to dissuade the development of new, cheaper energy resources in West Virginia that could deliver long term savings for ratepayers. Dissuading new development means missing out on local benefits of new projects in addition to long-term ratepayer savings—such as opportunities for local economic development, additional tax revenue, and reliability benefits from having diverse energy resources on the grid.

There are better alternatives to assure dependable and affordable electric supply

In order to achieve its objective, the task force should look at alternatives to increased reliance on coal to support energy affordability in West Virginia. These alternatives include increased reliance on the market to deliver the lowest cost energy possible, increasing fuel diversity by procuring wind and solar, and increasing funding to energy efficiency that can directly reduce energy consumption and customers’ electric bills.

Economic commitment and dispatch

The easiest way for utilities in West Virginia to deliver safe, reliable, and least cost energy to customers is for coal plants to operate according to economic commitment and dispatch within the PJM market. PJM’s centralized commitment and dispatch market rules and protocols are designed to deliver energy at least cost from any resource—including coal, gas, nuclear, solar, wind, batteries or demand response—while still keeping the lights on. PJM’s diverse set of resources and geographic footprint is also acts as a hedge that can protect customers from price volatility from any single fuel resource. However, this hedge
can be somewhat muted if the two dominate fuels (coal and gas) both spike at the same time, as they did in 2021 and 2022.

Energy efficiency

One of the best ways to address energy affordability is through energy efficiency and behind the meter resources that can directly lower the bills of low-income families.\textsuperscript{37} As noted above, low-income households endure higher levels of energy burden. This task force, with its focus on affordability, should seek to identify solutions such as increasing deployment of energy efficiency programs that have potential to benefit West Virginia households that suffer a disproportionate energy burden.\textsuperscript{38}

Incremental procurement of renewables

Building new local wind and solar is now cheaper than operating any coal plant in West Virginia.\textsuperscript{39} West Virginia utilities should ramp up procurement of renewable energy, taking advantage of recent federal incentives made available through the Inflation Reduction Act (IRA).\textsuperscript{40} Notably, the IRA not only improves upon and expands tax credits for

\begin{footnotesize}
\begin{enumerate}
\item EEFA. ND. “Reducing Energy Burdens.”
https://assets.ctfassets.net/ntcn17ss1ow9/7JPAB12O4ZLFedOvCr2jeU/bf80310e1583d9ef58a45670f6ea85c6/EEFA_Reducing_FS_02.pdf
https://crsreports.congress.gov/product/pdf/R/R47202
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\end{footnotesize}
renewable energy resources, but it also provides billions in low-cost financing through the energy infrastructure reinvestment program (EIRP) that can be used to reinvest in communities and assist utilities as they transition to cleaner energy. IRA tax credits are creating significant cost reductions for carbon-free sources of electricity including wind and solar – increasing the potential savings that building these types of generation could provide customers.

Incremental procurement could be achieved by issuing competitive requests for proposals (RFPs) from renewable energy developers. If the responses to the RFPs come in at prices lower than the operating costs of coal plants, then the utility companies can procure some or all of the available renewable energy at a cost savings. Using this approach annually or semi-annually, would enable the utilities to continue to test the market and identify opportunities to reduce costs by procuring incremental renewables.

Battery storage, in particular, is an essential tool in the quest for a more reliable electric grid, with the potential to revolutionize the grid the same way refrigeration revolutionized the food industry — moving from a just-in-time delivery system for low-cost energy to a system that can flexibly store and release power when needed. IRA tax credits for stand-alone storage strengthen the economic case for storage deployment.

Conclusion

The commission is rightfully focused on energy burden and affordability in West Virginia. The energy burden falls particularly hard on the state’s lowest income families. Families in West Virginia living at or below the poverty line that are served by any of the
four regulated utilities are all considered energy impoverished as their energy burdens are all over 10 percent, with a state average at 19 percent.

Data presented in these comments shows that there have been very few situations in the past four years when coal plants in the state could have economically run more. The majority of this period, coal plants could have run less at a savings to customers. Proposals that set artificial mandates for minimum capacity factors would increase costs to customers, supported by comments from AEP stating that running coal-fired units out-of-merit to achieve a 69 percent capacity factor, “may very well result in increased costs to customers.”

Moreover, setting long term policy at the commission based on a narrow window of data whose conditions have already begun to fade may also impact economic development opportunities. Requiring regulated companies in the state to flood the power markets with power will make for a less inviting environment for new energy technologies to be developed in the state.

In addition to the economic consequences, there is also the possibility of grid reliability impacts. If, in an attempt to hit capacity factor targets, coal plants are run when

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they aren’t needed, they may end up breaking down and not be available when they are needed. This risk was validated by ERCOT’s experience and West Virginia should be careful to avoid these same reliability issues.

Luckily, West Virginia ratepayers can benefit from low cost, reliable energy alternatives. Energy efficiency can alleviate energy burden, particularly when targeted and deployed at low-income families. Meanwhile, competitive procurement of renewable energy like wind and solar can help avoid utilities from having to purchase high-priced and volatile fossil fuels. The reliability benefits of renewables can be strengthened by pairing with batteries, and can be procured incrementally to take advantage of any current federal incentives (like those in the IRA) while also benefiting from any future cost.

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Appendix A: economics of regulated West Virginian power plants

To determine how economically West Virginian utilities have been operating regulated coal-fired power plants in PJM's day-ahead energy market, we compared the number of hours that these plants actually were operated each month to the number of hours that these plants should have operated if the decision to operate in the wholesale market were based entirely on economic dispatch. To achieve economic dispatch, grid operators dispatch the lowest-cost resources to meet demand, subject to grid constraints, and the last-called resource to operate sets the price that all operating generators get paid. A plant is economic to operate if its SRMC (reflected in the plant's bid into the energy market) does not exceed the locational marginal price of the nearest market node. In other words, a plant is economic to operate when its SRMC (fuel and VOM) do not exceed its energy market revenues (set by the locational market clearing price). In contrast, when the SRMC of a plant does exceed its energy market revenues, that plant is considered to be operating uneconomically.

Using plant-level fuel and VOM costs, we can determine the cost to generate at each of West Virginia's coal plants. Counting how frequently hourly market prices exceed expected reported operating costs shows how often each coal plant historically could have operated economically in the PJM energy market. When actual operating hours exceed that threshold, utilities are undoubtedly operating their coal plants uneconomically.

The following figures display the fraction of hours per month that each plant was operating, along with the fraction of hours that each plant should have been operating
based on reported fuel costs, with an additional coal price sensitivity.\textsuperscript{42} We included an additional coal-price sensitivity that estimates how frequently utilities would have been able to operate their coal plants economically had utilities been able to procure additional fuel at average spot prices during 2021 and 2022, spot prices which were unprecedentedly high and undoubtedly higher than the contract prices reported by utilities. In this sensitivity, the fuel cost of the plant is set by the estimated marginal cost of procuring fuel at spot market prices.

Highlighted in each chart is the period in which fuel shortages may have been a limiting factor in achieving economic dispatch (preceding winter 2021-2022). Over the past three years, the only period in which it appears as though fuel shortages may have been a limiting factor in achieving economic dispatch is the period preceding winter 2021-2022. In nearly every other period, the West Virginia coal fleet was operating much more frequently than economics would dictate, which comes at a cost to ratepayers. However, while this winter period appears anomalous over recent history, it does not incorporate other factors the utilities have stated for not running their coal plants as frequently as economics alone would suggest, including the need for maintenance.

\textsuperscript{42} The fraction of hours per month that each was operating is the average fraction of hours per month that each \textit{unit} at the plant was operating, weighted by the capacity of each unit.
Fort Martin Power Plant Economics: 2019-2022

- Fraction of hours operated (capacity weighted)
- Fraction of hours economic
- Fraction of hours economic with marginal cost of fuel

Values are the average fraction of hours per month that units at the plant were operated (weighted by unit capacity), and the fraction of hours per month that units at the plant were economic, based on both reported fuel costs and estimated fuel costs had utilities purchased coal at market prices.

Source: S&P Global

Harrison Power Plant Economics: 2019-2022

- Fraction of hours operated (capacity weighted)
- Fraction of hours economic
- Fraction of hours economic with marginal cost of fuel

Values are the average fraction of hours per month that units at the plant were operated (weighted by unit capacity), and the fraction of hours per month that units at the plant were economic, based on both reported fuel costs and estimated fuel costs had utilities purchased coal at market prices.

Source: S&P Global
John E Amos Power Plant Economics: 2019-2022

- Fraction of hours operated (capacity weighted)
- Fraction of hours economic
- Fraction of hours economic with marginal cost of fuel

Values are the average fraction of hours per month that units at the plant were operated (weighted by unit capacity), and the fraction of hours per month that units at the plant were economic, based on both reported fuel costs and estimated fuel costs that utilities purchased coal at market prices.

Source: S&P Global

Mitchell Power Plant Economics: 2019-2022

- Fraction of hours operated (capacity weighted)
- Fraction of hours economic
- Fraction of hours economic with marginal cost of fuel

Values are the average fraction of hours per month that units at the plant were operated (weighted by unit capacity), and the fraction of hours per month that units at the plant were economic, based on both reported fuel costs and estimated fuel costs that utilities purchased coal at market prices.

Source: S&P Global
Mount Storm Power Plant Economics: 2019-2022

- Fraction of hours operated (capacity weighted)
- Fraction of hours economic
- Fraction of hours economic with marginal cost of fuel

Values are the average fraction of hours per month that units at the plant were operated (weighted by unit capacity), and the fraction of hours per month that units at the plant were economic, based on both reported fuel costs and estimated fuel costs that utilities purchased coal at market prices.

Source: S&P Global

Mountaineer Power Plant Economics: 2019-2022

- Fraction of hours operated (capacity weighted)
- Fraction of hours economic
- Fraction of hours economic with marginal cost of fuel

Values are the average fraction of hours per month that units at the plant were operated (weighted by unit capacity), and the fraction of hours per month that units at the plant were economic, based on both reported fuel costs and estimated fuel costs that utilities purchased coal at market prices.

Source: S&P Global