PUBLIC-REDACTED VERSION

STATE OF NORTH CAROLINA
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
	)	
Application of Duke Energy Progress, LLC Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	))))))	**DOCKET NO. E-2, SUB 1358**

PUBLIC-REDACTED DIRECT TESTIMONY AND EXHIBITS

OF

MICHAEL GOGGIN

AND ON BEHALF OF

THE SOUTHERN ALLIANCE FOR CLEAN ENERGY AND SIERRA CLUB

SEPTEMBER 2, 2025

PUBLIC-REDACTED VERSION

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EXHIBITS

I. Introduction and Qualifications

Q. PLEASE STATE YOUR NAME AND PROFESSIONAL POSITION.

A. My name is Michael Goggin, and I am a Vice President at Grid Strategies, LLC, which is incorporated in Bethesda, Maryland.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Southern Alliance for Clean Energy and Sierra Club (SACE, *et al.*), as represented by the Southern Environmental Law Center.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND WORK EXPERIENCE.

A. I have worked on electric utility regulatory issues for nearly twenty years. At Grid Strategies, LLC, I have served as an expert on utility regulatory topics for a range of clients interested in clean energy over the last seven years, including state utility regulators, consumer advocates, grid operators, and non-profit organizations. For the preceding ten years, I was employed by the American Wind Energy Association (AWEA), now known as the American Clean Power Association, where I provided technical analysis and advocacy on electricity market and transmission matters. This included directing AWEA's research and analysis team from 2014–2018. Prior to that, I was employed at a firm serving as a consultant to the U.S. Department of Energy, and at two environmental groups.

Over the course of my career, I have co-authored over one hundred filings to the Federal Energy Regulatory Commission (FERC); served as a technical reviewer for over a dozen national laboratory reports, academic articles, and renewable integration studies; and published academic articles and conference presentations on renewable energy, transmission, and electricity policy. I have also served as an elected member of the Standards, Planning, and Operating Committees of the North American Electric Reliability Corporation (NERC). I hold an undergraduate degree with honors from Harvard University. A copy of my resume is included as Exhibit MG-1.

Q. HAVE YOU SERVED AS AN EXPERT WITNESS BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes. I have testified dozens of times before state utility regulators, including in the states of Arizona, Colorado, Georgia, Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, South Carolina, Virginia, Washington, and Wisconsin, as well as before FERC.

Q. IN WHAT CASES HAVE YOU BEEN AN EXPERT WITNESS BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. I testified in Docket E-7, Sub 1276, Duke Energy Carolinas, LLC's general rate case and application for performance-based regulation; and Docket E-100, Sub 190, the 2023 Duke Energy Carbon Plan and Integrated Resource Plan (CPIRP) before the North Carolina Utilities Commission (the Commission or NCUC).

II. Testimony Overview

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony first provides background on how economic dispatch efficiently determines which power plant units operate by dispatching the lowest-cost resources first. That section also explains how uneconomic dispatch, either due to designating higher-cost generators as "must-run" resources or simply using inputs that excessively dispatch higher-cost resources, results in excessive costs for Duke Energy Progress (DEP or the Company) ratepayers.

The bulk of my testimony then presents analysis that identifies **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of ratepayer net losses during the test period at issue in this case, April 1, 2024, to March 31, 2025, due to uneconomic dispatch of the Mayo and 4-unit Roxboro coal power plants. These losses occurred because DEP either designated a unit as must-run or otherwise dispatched it uneconomically, even though DEP's own data show lower-cost resources were available on its system and on neighboring power systems. These total ratepayer losses over the year represent net losses, after factoring in startup costs and other costs in the counterfactual case wherein the unit was shut down and then restarted once power prices were high enough to economically justify its operation, instead of remaining online.

The next section of my testimony then reviews a variety of factors that could result in uneconomic dispatch, explains why each of these is an invalid justification for the resulting ratepayer costs, and recommends solutions to reduce or eliminate these causes of uneconomic dispatch. Finally, I review the costs and risks for ratepayers due to DEP increasing its dependence on gas generation.

Q. WHAT RECOMMENDATIONS DO YOU HAVE FOR THE COMMISSION?

A. I respectfully recommend that the Commission disallow recovery of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in net losses that occurred because of imprudent dispatch decisions for DEP's coal fleet. This will protect ratepayers from shouldering these imprudently incurred costs, and more importantly will incentivize DEP to avoid uneconomic dispatch going forward.

Most importantly, the Commission should direct DEP to remove persistent biases in inputs into DEP's commitment and dispatch software that result in suboptimal dispatch. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

I further recommend that the Commission direct DEP to not use must-run designations or other forms of uneconomic dispatch for factors that are adequately accounted for in economically optimized commitment and dispatch, such as **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

I also recommend that the Commission direct DEP to not negotiate coal supply and transportation contracts that include penalties for failing to meet minimum fuel delivery requirements. As explained below, those contract terms can cause DEP to run those plants even when they are not economic, resulting in their excessive and costly operation. In future fuel factor cases, the Commission should also review new or extended fuel supply or transportation contracts to ensure they do not include penalties associated with minimum fuel delivery requirements

I also recommend that the Commission direct DEP to take all feasible and cost-effective steps to minimize costs associated with must-run designations for unit testing, such as scheduling generator testing that is not time-sensitive during months when power prices are typically high and, to the extent possible, conducting multiple types of testing in parallel to minimize the duration of must-run designations for testing.

Finally, I recommend that the Commission account for the risks of gas price volatility when weighing the prudence of DEP increasing its dependence on gas generation and require DEP to take steps to more effectively manage that risk through expanded use of contracts and hedges.

III. Background on Economic Dispatch

Q. HOW DO UTILITIES TYPICALLY CHOOSE WHICH POWER PLANTS TO OPERATE?

A. Utility generation dispatch is designed to ensure that a generating facility with the lowest incremental cost of producing an additional megawatt-hour (MWh) of electricity, also referred to as marginal cost or marginal production cost, is used first before a higher-cost resource like a coal plant is dispatched, which minimizes ratepayer costs. Incrementally more expensive generation is then dispatched until generation supply meets demand. A power plant's marginal production cost includes its fuel cost and other variable operations and maintenance (O&M) costs that increase in proportion to the MWh generated at the plant. Capital and other fixed costs do not factor into the decision about which power plants are selected because those sunk costs are incurred regardless of whether the power plant operates. As a result, wind and solar resources that have no fuel cost and minimal variable O&M costs are typically dispatched first, generally followed by other resources with low marginal production costs like hydropower and nuclear, with the grid operator progressing through the remaining available resources in order of increasing marginal production cost. While coal units are increasingly expensive to maintain and operate, whether a specific coal unit is the highest marginal cost resource in a given hour will depend upon the specific variable costs associated with running that unit relative to other resources' variable costs. As noted previously, the variable costs to dispatch a unit depend upon input costs like fuel, the price of which is driven by real-time supply and demand factors, and other dynamics specific to each unit, including its variable maintenance costs and its efficiency or heat rate where applicable. In addition, system dynamics such as whether the utility is experiencing a daily or seasonal peak will inform what resources are needed in that moment and in what quantities. Taken together, these factors ultimately inform the marginal cost of committed resources. Accordingly, some natural gas combined cycle generators have a lower marginal production cost than some coal plants, while gas combustion turbines are less efficient and therefore generally have a higher marginal production cost.

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]** This process "commits" units based on forecasts for electricity demand and other factors, which provides time for inflexible generators like coal plants to start up and gas generators to procure fuel. DEP then fine-tunes dispatch to match changes in supply and demand that occur after day-ahead commitment. As outlined below, my concern is that DEP deviating from those least-cost dispatch principles, which is increasing ratepayer costs.

[1] Company's Confidential Response to SACE, *et al.* DR 1.9.

Q. HOW DOES UNECONOMIC DISPATCH SPECIFICALLY HARM DEP CUSTOMERS?

A. My analysis indicates that many DEP coal units are routinely operating at a loss, reflecting that their marginal cost of producing electricity is greater than that of other resources that were available on DEP's system and on neighboring power systems. This indicates that the cost for the coal unit to produce that electricity is greater than the value of that electricity. Said another way, DEP ratepayers would have saved money if DEP replaced the coal generation with energy generated by another resource. This excess cost is passed on to DEP ratepayers through the fuel rider, which is determined in this proceeding. This uneconomic dispatch of coal also displaces generation from lower-cost resources like solar and hydropower, and in some cases from lower-cost gas combined cycle generation.

The costs for ratepayers are particularly high when uneconomic dispatch results in the curtailment of renewable generation, replacing a non-emitting and zero-marginal-cost resource with costly coal generation. Depending on the terms of DEP's solar power purchase agreements, renewable curtailment can even result in DEP having to compensate renewable power producers for lost revenue, further increasing the cost of uneconomic dispatch to DEP ratepayers. By displacing lower-cost and lower-emitting generation, uneconomic coal dispatch also increases emissions of pollutants that harm public health and the environment.

Q. ARE VERTICALLY INTEGRATED UTILITIES LIKE DEP MORE LIKELY TO UNECONOMICALLY DISPATCH THEIR FOSSIL GENERATION?

A. Yes. In contrast to merchant generators whose profits are reduced by uneconomic generation, fuel costs do not affect the profits of vertically integrated utilities like DEP, which pass their fuel costs through to their ratepayers in proceedings such as this one. Many analysts have found that vertically integrated utilities are much more likely to uneconomically dispatch their coal plants than merchant plant owners because it does not affect their profits.[2] Vertically integrated utilities' economic indifference to fuel costs requires diligent regulation from state utility commissioners to protect ratepayers from imprudent dispatch decisions.

Q. WHAT IS A MUST-RUN DESIGNATION?

A. One form of uneconomic dispatch is a must-run designation. When a utility designates a unit as must-run, it elects to operate the unit regardless of economics. As a result, the unit will run even if it has a higher cost than the marginal resource that was selected through economic dispatch, which results in costs for ratepayers. There can be legitimate reasons for a plant owner to use a must-run designation, such as for generator testing that requires the plant to operate. However, as discussed in Section V, it

[2] *See* Catherine Morehouse, *MISO Integrated Utilities Lost $492M From 2016-2019 Via Uneconomic Coal Dispatch: Market Monitor*, UTILITY DIVE (Oct. 9, 2020), https://www.utilitydive.com/news/miso-integrated-utilities-lost-492m-from-2016-2019-via-uneconomic-coal-dis/586714/; JOE DANIEL ET AL., UNION OF CONCERNED SCIENTISTS, USED, BUT HOW USEFUL?: HOW ELECTRIC UTILITIES EXPLOIT LOOPHOLES, FORCING CUSTOMERS TO BAIL OUT UNECONOMIC COAL-FIRED POWER PLANTS (2020), https://www.ucsusa.org/sites/default/files/2020-05/Used%20but%20How%20Useful%20May%202020.pdf; RMI, *Economic Dispatch Dashboard*, UTILITY TRANSITION HUB, https://utilitytransitionhub.rmi.org/economic-dispatch/ (last visited July 15, 2025).

appears that in at least some cases, DEP's use of must-run designations was imprudent or the cost impact to ratepayers could have been reduced.

IV. Method of Analysis and Results

Q. WHAT WAS YOUR METHOD OF ANALYSIS?

A. For each hour in the test period of April 2024-March 2025, I assessed whether the marginal production cost of an operating coal unit[3] exceeded DEP's system-wide marginal production cost, a metric that is also known as system "lambda."[4] System lambda measures the marginal cost of incremental generation from the highest cost unit dispatched across DEP's system to meet electricity demand in that hour. In conducting this analysis, I used the hourly system lambdas that DEP provided through discovery, which varied depending on the incremental fuel costs and other incremental variable costs of the resources DEP dispatched during those specific hours. If an operating coal unit's marginal production cost exceeded the system lambda, this indicates that the unit was uneconomic relative to other available resources, and thus DEP incurred a loss by operating the unit in that hour. To calculate the net cost of DEP keeping a coal unit online, for each must-run event, I also factored in the startup and shutdown costs for the unit to calculate the cost of the alternative or counterfactual of the unit shutting down and then restarting once power

[3] *See* Company's Confidential Response, including CONFIDENTIAL 2025 SACE DR 1.4.1-1.4.4 DEP Coal Unit Fuel Detail and DEP NC SACE DR 1.4.5. attachments, to SACE, *et al*. DR 1.4 (providing hourly components of marginal production costs for the coal units).
[4] *See* Company's Confidential Response, including SACE DR 1.3.1 DEC System Lambda Hourly Detail for the Period 4/1/2024-3/31/2025 attachment, to SACE, *et al.* DR 1.3.1.

prices were high enough for it to profitably operate.[5] Put simply, this counterfactual was intended to assess whether the costs associated with shutting off and restarting a high marginal cost coal unit would outweigh the savings from using a lower marginal cost alternative resource. As a result, time periods in which a coal unit was unprofitable, but shutting it down and restarting it would have resulted in higher net costs to ratepayers, were not counted in our analysis as they did not impose a net cost on ratepayers. Because my analysis accounts for net costs over a multi-day period relative to alternative dispatch decisions, it addresses concerns raised in past fuel adjustment clause proceedings[6] that coal dispatch decisions should be evaluated on a multi-day basis and not instantaneous basis. I also incorporated DEP's reported coal unit operating constraints, including startup time, minimum uptime, and minimum downtime when designing this counterfactual.[7] Accounting for these start up and shutdown costs and other operating constraints reduced the number of periods that resulted in a net cost for purposes of this case, as those dispatch decisions were arguably prudent for DEP's existing generating fleet. However, transitioning to a fleet with more flexible resources, like battery storage, will reduce the need to unprofitably operate inflexible coal resources.

[5] *See* Company's Confidential Responses, including CONFIDENTIAL DEP NC SACE DR 1.12 attachment, to SACE, *et al.* DRs 1.12.6 and 1.12.10.
[6] *See, e.g.*, Order Approving Fuel Charge Adjustment, *In the Matter of Application of Duke Energy Carolinas, LLC, Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities*, Docket No. E-7, Sub 1250, at 13-14 (N.C.U.C. Aug. 17, 2021) (2021 DEC Fuel Rider Order).
[7] *See* Company's Confidential Responses to SACE, *et al.* DRs 1.12.3, 1.12.4, and 1.12.11.

Q. WHY DID YOU COMPARE THE COAL UNITS' COST(S) AGAINST SYSTEM LAMBDA?

A. Because system lambda reflects the incremental cost of generation from the highest cost unit dispatched across DEP's system to meet electricity demand in that hour, it is a metric of the marginal cost of producing electricity in that hour. If the coal unit's cost is higher than system lambda, this indicates that the lower-cost generator setting the system-wide lambda, and in many cases other resources as well, could have more economically provided that generation than the coal unit. Operating coal units can have a higher cost than system lambda because they are relatively inflexible, are typically committed day-ahead, and often cannot quickly change their level of output to provide incremental generation that is factored into setting system lambda.

To validate these results, I also compared the cost of operating each coal unit against the price in the Day-Ahead market at the nearest pricing hub in PJM Interconnection, LLC (PJM), as explained in more detail further below. Because these market prices were set at the day-ahead timeframe when DEP made decisions about which units to commit to operate the next day, they validate whether those commitment decisions were prudent given the information available to DEP at the time. Day-ahead unit commitment is the typical utility practice of deciding which power plants will operate the next day, so that resource operators can make any necessary preparations, like starting up their units or procuring fuel. This validation using Day-Ahead prices addresses concerns raised in previous proceedings[8] that system lambda is a real-time measurement that can differ from the information available to DEP in the day-ahead timeframe when it made decisions about which generators to commit to operate.

Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS BASED ON SYSTEM LAMBDA?

A. The charts and table below report the net ratepayer cost for all uneconomic dispatch events that resulted in a net cost. Figure 1 sums the total net cost of uneconomic dispatch by unit, breaking out the share of uneconomic dispatch costs that occurred in periods with must-run designations versus other factors, while Table 1 reports the same information in tabular form. As noted above, these net costs total **[BEGIN CONFIDENTIAL]** [redacted]

[8] *See, e.g.*, 2021 DEC Fuel Rider Order at 13.

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[END CONFIDENTIAL]

Q. WHAT FACTORS CAN CAUSE UNECONOMIC DISPATCH?

A. As shown in Table 1 above, factors that cause uneconomic dispatch can generally be grouped into a utility designating a unit as must-run, and other factors that result in a flawed and uneconomic dispatch outcome. These other factors can include systemic biases in the inputs into the economically optimized generator dispatch, as discussed below.

Q. DID YOU VALIDATE SYSTEM LAMBDA AGAINST OTHER METRICS OF THE SYSTEM MARGINAL COST OF ENERGY?

A. Yes. I re-ran the analysis to compare the cost of operating a coal plant against the price of electricity in the Day-Ahead market at the PJM South trading hub that DEP provided, instead of DEP's reported system lambda.[9] PJM operates two different energy markets:

- The Day-Ahead market selects which resources are "committed" to operate in each hour of the next day, giving plant operators enough time to procure fuel and start up.
- The Real-Time market fine-tunes supply shortly before each 5-minute dispatch interval to match any changes in supply and demand that occur after the Day-Ahead market is run.

Coal plants sell the vast majority of their energy in the Day-Ahead market, at least in part due to their limited flexibility, so this comparison exclusively focused on prices in the Day-Ahead market. As a result, Day-Ahead market prices provide an important validation that DEP's system lambda accurately reflects the supply and demand balance and generator economics in the day-ahead timeframe when DEP decided which power plants to commit to operate so that long startup time coal units could be online by the next day. **[BEGIN CONFIDENTIAL]** [redacted]

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[9] *See* Company's Confidential Response, including CONFIDENTIAL 2025 SACE DR1.3.12 PJM South DA LMP attachment, to SACE, *et al.* DR 1.3.12.
[10] *See* Company's Confidential Response, including CONFIDENTIAL DEP NC SACE DR 1.12 attachment, to SACE, *et al.* DR 1.12

[redacted] **[END CONFIDENTIAL]** This data, and the comparison against the multi-day net costs of shutting a unit down and restarting it, therefore accurately indicate whether DEP's coal commitment and dispatch decisions were prudent.

Q. WHAT DID THIS VALIDATION SHOW?

A. The validation confirms that the results based on DEP's system lambda are reasonable. Specifically, the net costs of DEP's uneconomic dispatch total **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

V. <u>Dissecting the Factors That Drive Uneconomic Dispatch</u>

Q. WHAT FACTORS CAN CAUSE UNECONOMIC DISPATCH?

A. As outlined above, factors that cause uneconomic dispatch can generally be grouped into a utility designating a unit as must-run, and other factors that result in a flawed and uneconomic dispatch outcome. This section reviews those factors in more detail and develops recommendations for the Commission to address these problems.

Q. WHAT FACTORS CAUSED DEP TO USE MUST-RUN DESIGNATIONS DURING THE TEST PERIOD?

A. In response to discovery, DEP indicated days when each coal unit was designated as a must-run unit, as well as the Company's stated reason for making that designation.[11] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. HOW CAN DEP REDUCE THE RATEPAYER COST OF MUST-RUN DESIGNATIONS FOR TESTING?

A. For the types of testing that require the unit to be operating but are not time-sensitive, DEP should take all feasible steps to schedule that testing when higher loads and thus higher prices are expected, like the summer and winter seasons. In response to discovery, DEP indicates that it typically schedules generator testing during periods of low demand,[13] which indicates ratepayers could realize significant savings if DEP instead scheduled testing that requires a unit to run during periods when demand is expected to be high. In the course of updating its testing scheduling practices, DEP should also account for how the evolution of the

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[11] *See* Company's Confidential Response, including DEP NC SACE DR 1.4.5. attachment, to SACE, *et al.* DR 1.4.5.

[12] For public background provided by DEP regarding its stated reason for LROL reserves, *see* Michael Mazzola, Kat Sico, & Steven Whisenant, *Applying Flexible Resources to Store Excess Renewable Energy*, T&D WORLD (Jan. 28, 2019), https://www.tdworld.com/distributed-energy-resources/energy-storage/article/20972170/applying-flexible-resources-to-store-excess-renewable-energy. For additional information, *see* Company's Confidential Response to SACE DR 3.3.

[13] *See* Company's Response to SACE, *et al.* DR 2.3.1.

generation mix is changing seasonal price patterns, such as moving testing from summer to winter as increased solar and battery generation reduces prices during the summer and increased dependence on volatilely priced gas generation increases prices during winter peak demand periods.

To the extent practical, DEP should also expand its efforts to concurrently schedule unit testing that can be done in parallel. This will minimize the number of hours and thus the potential cost from must-run designations for testing.

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[END CONFIDENTIAL]

Q. CAN OTHER FACTORS CAUSE THE USE OF MUST-RUN DESIGNATIONS?

A. As DEP notes,[14] another reason that coal plants can operate uneconomically, either by a utility using a must-run designation or an artificially low fuel cost in the economic dispatch model, is to use up surplus coal supplies to avoid penalties associated with minimum delivery requirements in coal supply or transportation contracts. While this does not appear to have occurred during the test period based on the data provided by DEP, the Commission can take steps now to ensure that this type of uneconomic dispatch does not occur in the future by requiring DEP to move to more efficiently structured contracts for coal supply and delivery that do not include such penalties as new fuel contracts are signed or existing contracts come up for renewal.

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[14] *See* Company's Response to SACE, *et al.* DR 1.5.

Q. WHAT DOES AN ECONOMICALLY EFFICIENT FUEL CONTRACT USE INSTEAD OF MINIMUM DELIVERY PENALTIES?

A. In an economically efficient contract, the price DEP would pay for each ton of coal delivered would only include the marginal cost of extracting and delivering that fuel. While a coal mine operator or railroad does have fixed costs associated with building and operating the infrastructure necessary to produce and deliver coal, those fixed costs should be recovered separately from the variable per-unit price of the fuel. Capital and other fixed costs associated with that infrastructure should be recovered as fixed costs in the fuel supply contract, such as through a one-time payment or a fixed cost per year. Fuel contracts that use minimum delivery requirements and penalties to recover fixed costs are inherently inefficient as these fixed costs should not affect the marginal cost of the fuel.

Q. ASIDE FROM MUST-RUN DESIGNATIONS, WHAT OTHER FACTORS CAUSE UNECONOMIC DISPATCH?

A. Biases or other flaws in the inputs into the economically optimized generator commitment and dispatch process can result in suboptimal dispatch that increases ratepayer costs. In response to discovery, DEP provided[15] **[BEGIN CONFIDENTIAL]** [redacted]

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[15] *See* Company's Confidential Response, including 2025 SACE DR1.3.3 DEC & DEP System Load and DEC & DEP Unit Loading Reports attachments, to SACE, *et al.* DRs 1.3.3 and 1.3.4.

[redacted] **[END CONFIDENTIAL]** A statistical t-test[16] confirms that an over-forecasting bias of this size exceeds the deviation expected due to normal forecast error by many orders of magnitude. This persistent and significant load over-forecasting bias can result in the overcommitment of coal units to meet forecasted demand that in many cases does not materialize, which results in uneconomic dispatch of those coal units to the detriment of ratepayers.

VI. Gas Price Risk

Q. WHAT ARE THE LENGTHS OF THE GAS SUPPLY CONTRACTS THAT DEP USES TO FUEL ITS GAS GENERATORS?

A. In response to discovery, DEP broke down the contract tenor of its gas purchases over the test period.[17] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** As a result, gas price increases over those time periods will directly increase ratepayer costs.

Q. IS GAS PRICE VOLATILITY A MAJOR RISK FOR DEP RATEPAYERS?

A. Yes. While gas prices were relatively low during the test period, there is a major risk that they will increase in the future. Gas prices are highly

[16] A statistical t-test compares the averages between two sampled groups to determine whether the variance in those averages is statistically significant.
[17] *See* Company's Confidential Response, including CONFIDENTIAL 2025 SACE DR1-14-Natural Gas Spot and Non-Spot Purchases attachment, to SACE, *et al.* DR 1.14.

volatile on both a day-to-day basis due to weather, and on a year-to-year basis due to economic and geopolitical factors.

Driving long-term uncertainty, increased U.S. exports of liquefied natural gas have increasingly tethered domestic gas prices to the global price for gas, which is higher and heavily affected by geopolitical volatility that seems likely to persist or even increase. Domestic natural gas prices may also experience greater volatility as more gas is used domestically for electricity generation, and extreme weather events that affect both gas and electricity demand increase in magnitude and frequency. Moreover, ongoing consolidation in the gas supply and transportation industries may result in higher and more volatile gas prices. Ernst and Young reports that oil and gas industry "[m]erger and acquisition expenditures increased 331% in 2024, from US$47.9 billion in 2023, to US$206.6 billion in 2024."[18] For example, the largest gas producer in the Appalachian basin has recently completed acquisitions and announced plans to increase prices by reducing production.[19]

[18] ERNST AND YOUNG, US OIL AND GAS RESERVES, PRODUCTION AND ESG BENCHMARKING STUDY 6 (2025), https://www.ey.com/content/dam/ey-unified-site/ey-com/en-us/industries/oil-gas/documents/ey-us-oil-and-gas-reserves-production-esg-study-2025-final.pdf.

[19] *See, e.g.*, *EQT Announces Strategic Production Curtailment*, EQT (Mar. 4, 2024), https://ir.eqt.com/investor-relations/news/news-release-details/2024/EQT-Announces-Strategic-Production-Curtailment/default.aspx; Narciso Cano, *EQT's Q2 Call Highlights Strategic Shift Toward Demand-Linked Growth*, AEGIS HEDGING (July 25 2025), https://aegis-hedging.com/insights/eqts-q2-call-highlights-strategic-shift-toward-demand-linked-growth; *EQT to buy Olympus Energy assets for $1.8 bln to boost Marcellus presence,* REUTERS (Apr. 22, 2025), https://www.reuters.com/business/energy/eqt-acquire-upstream-midstream-assets-olympus-energy-18-billion-2025-04-22/.

Gas prices also show major volatility on a daily basis. While an extreme weather event like 2022's Winter Storm Elliott did not occur during the test period, DEP should not rest on its laurels based on that good fortune.

Q. HOW CAN THE COMMISSION REDUCE THAT RISK AND RATEPAYERS' EXPOSURE TO THAT RISK?

A. As an initial step, the Commission should require DEP to more effectively manage that gas price risk by expanding long-term contracts and hedges. In line with the proposal(s) set forth in the North Carolina Sustainable Energy Association's expert witness testimony in this proceeding, which I have reviewed and endorse, the Commission should require DEP to adopt a fuel cost sharing mechanism. Fuel cost sharing mechanisms are particularly effective tools to help reduce ratepayers' exposure to gas price risk and incentivize utilities to adopt additional strategies to reduce their overall exposure to gas price volatility. More importantly, in other proceedings, the Commission should thoroughly weigh the economic and reliability risks for ratepayers from DEP increasing its dependence on gas generation, as well as the limits to even the best contractual mechanisms for hedging that risk. For example, widespread regional interruptions to gas supply or pipeline *force majeure* events can threaten gas delivered even under firm transportation contracts. The freezing of gas wells in the Marcellus and Utica shale gas formations played a major role in causing widespread correlated gas generator outages during Winter Storm Elliott that resulted in rolling blackouts and other reliability problems,[20] and a similar freezing of gas wells in the Permian Basin precipitated the prolonged power outages Texas customers experienced during Winter Storm Uri.[21] Gas generators accounted for 63% of unplanned outages and derates during Winter Storm Elliott,[22] and 55% during Winter Storm Uri[23] and the 2014 Polar Vortex.[24] The most resilient solution to reducing gas price risk is diversifying DEP's fuel mix by adding resources that do not rely on fuel deliveries, like renewable and battery resources.

VII. Conclusion

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I respectfully recommend that the Commission disallow recovery of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in net ratepayer losses that occurred as a result of uneconomic coal unit dispatch. This will protect ratepayers from shouldering these imprudently incurred costs, and more importantly will incentivize DEP to not imprudently use must-run designations going forward.

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[20] FERC AND NERC, INQUIRY INTO BULK-POWER SYSTEM OPERATIONS DURING DECEMBER 2022 WINTER STORM ELLIOTT 9 (2023) https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.

[21] FERC AND NERC, THE FEBRUARY 2021 COLD WEATHER OUTAGES IN TEXAS AND THE SOUTH CENTRAL UNITED STATES 83 (2021) https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[22] FERC AND NERC, DECEMBER 2022 WINTER STORM ELLIOTT GRID OPERATIONS: KEY FINDINGS AND RECOMMENDATIONS 5 (2023), https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott.

[23] FERC AND NERC, THE FEBRUARY 2021 COLD WEATHER OUTAGES IN TEXAS AND THE SOUTH CENTRAL UNITED STATES 16 (2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[24] NERC, POLAR VORTEX REVIEW 13 (2014), https://www.nerc.com/pa/rrm/ea/Documents/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

To that end, I further recommend that the Commission direct DEP to take prudent and cost-effective steps to minimize or eliminate uneconomic dispatch going forward. Specifically, the Commission should direct DEP to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and other flaws in the inputs into the economically optimized generator commitment and dispatch process that result in suboptimal dispatch that increases ratepayer costs.

Finally, the Commission should require DEP to more effectively manage gas price risk through contracts and more efficient hedges. In other proceedings, the Commission should thoroughly weigh the economic and reliability risks for ratepayers from DEP increasing its dependence on gas generation relative to renewable and battery resources that are not subject to volatile fuel prices.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes

PUBLIC-REDACTED VERSION

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Michael Goggin on behalf of the Southern Alliance for Clean Energy and Sierra Club either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 2nd day of September, 2025.

s/ Munashe Magarira

Munashe Magarira

Michael Goggin

Education:

Harvard University class of 2004, B.A. *cum laude* in Social Studies

- Wrote thesis "Is it Time for a Change? Science, Policy, and Climate Change"

Experience:

Grid Strategies — Vice President — February 2018-present

- Serve as an expert consultant on electricity transmission, grid integration, reliability, market, and policy issues for non-profit, grid operator, state regulator, and industry clients
- Have testified before FERC and in dozens of state regulatory commission cases
- Actively engaged in NERC Standards development processes related to renewable and storage resources

AWEA — Senior Director of Research, other titles — February 2008-February 2018

- Led team responsible for all American Wind Energy Association analysis
- Served as primary technical and economic expert on market design, transmission, grid integration, carbon policy, and other topics
- Authored regulatory filings at state (IRP and transmission siting cases), regional (RTO transmission and market design), and federal levels (FERC transmission, interconnection standard, grid integration, and market design cases; EPA carbon policy)
- Directed economic and power sector modeling to inform AWEA's policy strategy and support advocacy positions
- Communicated with the press and policy makers about wind energy
- Other titles included Electric Industry Analyst, Senior Analyst, Manager of Transmission Policy, Director of Research

Sentech, Inc. — Research Analyst — October 2005-February 2008

- Conducted economic analyses of solar, wind, geothermal, hydrogen, and energy storage technologies for U.S. Department of Energy officials
- Provided analytical support for DOE's renewable energy R&D funding decisions

Union of Concerned Scientists — Clean Energy Intern — May 2005-October 2005

- Worked with the legislative and field staff to promote the inclusion of pro-renewable energy measures in the Energy Policy Act of 2005

State Public Interest Research Groups — Policy Analyst — August 2004-May 2005

- Analyzed and advocated for clean energy policies at the state and federal level

Publications available at https://gridstrategiesllc.com/reports/

SACE
Docket No. E-2, Sub 1358
2025 DEP Fuel
SACE Data Request No. 2
Item No. 2-3
Page 1 of 1

DUKE ENERGY PROGRESS, LLC

Request:

Please see the Company's response to SACE DR 1-11. When scheduling generator testing that requires a unit to operate, please explain if and how the Company:

> 2.3.1 Schedules that testing for seasons when electricity demand is typically high. If the Company does not do this, please explain why.
>
> 2.3.2 To the extent feasible, schedules multiple types of testing to occur concurrently. If the Company does not do this, please explain why.

Response:

To the extent the term "generator testing" refers to testing performed on a generating unit, the Company responds as follows:

2.3.1 - Generating facility required testing is typically managed within the Company's work management system. Testing work orders are generated in advance of the planned testing and with enough lead time to allow for flexibility in scheduling based on station and system conditions.

Once testing work orders are generated, the station utilizes the Company's Constrained Operation Application (COA) tool to request the expected durations and conditions needed to support testing.

Transmission Operations, the Energy Control Center, and Plant Operations then use the information from the COA tool to coordinate closely to best maximize the timing and need for unit testing to minimize the impact to system reliability. Where possible, testing is scheduled for periods with the least impact to the system, including during seasons when electricity demand is typically low.

2.3.2 - See response to 2.3.1. Additionally, to the extent possible, the Company will work to schedule unit testing that can be performed utilizing similar unit conditions concurrently while minimizing system impacts.

Responder: Israel Cortes, Developmental Assignment