BEFORE THE NORTH CAROLINA UTILITES COMMISSION

DOCKET NO. E-2, SUB 1272

IN THE MATTER OF	)	
APPLICATION OF DUKE ENERGY	)	
PROGRESS, LLC PURSUANT TO	)	**DIRECT TESTIMONY OF**
N.C.G.S. § 62-133.2 AND	)	**DEVI GLICK ON BEHALF OF**
COMMISSION RULE R8-5	)	**THE SIERRA CLUB**
RELATING TO FUEL AND FUEL-	)	
RELATED CHARGE ADJUSTMENTS	)	
FOR ELECTRIC UTILITIES	)	

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Principal Associate at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power. Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, utility resource planning practices, valuation of distributed energy resources, and utility handling of coal combustion residuals waste. I have submitted expert testimony on unit-commitment practices, plant economics, utility resource needs, and solar valuation before state utility regulators in North Carolina, Arizona, Connecticut, Florida, Indiana, Michigan, Nevada, New Mexico, South Carolina, Texas, Wisconsin, and Virginia. In the course of my work, I develop in-house electricity system models and perform analysis using industry-standard electricity system models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than eight years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit DG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of the Sierra Club.

Q Have you testified previously before the North Carolina Utilities Commission ("Commission")?

A Yes, I submitted testimony in Docket No. E-7, Sub 1250, the most recent Duke Energy Carolinas fuel cost adjustment proceeding. I also submitted testimony in Docket No. E-100, Sub 158, the 2018 biennial proceeding regarding avoided cost rates.

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

A My testimony addresses the analysis and decision-making processes Duke Energy Progress ("DEP" or the "Company") uses to commit (turn on, keep on, or turn off) and dispatch (turn up or down once a unit is committed) its coal-fired power plants at Mayo and Roxboro. In particular, I evaluate the fuel costs included in the subset of production costs that DEP used to make its unit-commitment decisions in the test-year period of April 1, 2020 through March 31, 2021 (i.e., the marginal production cost). I compare those to the fuel costs included in the average or full cost of production, which represent the fuel costs that the Company seeks to recover from ratepayers in this docket. I explain how the significant discrepancy between the marginal and average cost of production is driving DEP's uneconomic commitment of its coal plants and evaluate the impact DEP's underrepresentation of its actual or average unit costs had on ratepayers in the test-year period. Finally, I outline recommendations for improving the transparency and functioning of the Company's unit-commitment process to better serve ratepayers.

Q Why is the issue of unit commitment relevant to this fuel clause adjustment proceeding?

A North Carolina law says that the utility can recover the "reasonable costs of fuel and fuel-related costs prudently incurred during the test period."[1] DEP's incurred fuel costs, along with its other variable costs, are inputs into the Company's unit-commitment process, and therefore they are directly tied to the utility's decision to operate each of its units. Comparing the level of fuel and other variable costs incurred at its coal plants to the cost to operate other units on the system in turn informs the Commission's determination of whether fuel costs at DEP's coal plants were reasonable and prudently incurred.

In the past, utilities operated their coal-fired plants as baseload resources where they were not regularly turned on or off. But, in recent years low gas prices and nearly-zero-variable-cost renewables have pushed coal generation to become marginal on many systems and therefore more costly than other resources available during many hours of the year. The practice of committing coal plants to run when there are lower-cost resources on a Company's system saddles ratepayers with avoidable excess fuel costs, should they be recovered in dockets like this one. This practice thereby allows utilities to continue operating aging and

[1] N.C. Gen. Stat.§ 133-2(d).

costly coal plants when there are lower-cost alternatives that can meet customers' needs.

Q How is the remainder of your testimony structured?

A The remainder of my testimony is structured as follows:

In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I define the terms "unit commitment" and "dispatch" and describe how electric utilities such as DEP make daily operational decisions at coal-fired power plants. I explain the practice of uneconomic unit commitment and outline reasons why utilities may utilize this practice.

In Section 4, I review the marginal production costs DEP uses to make its unit-commitment decisions at its coal units and I quantify the excess fuel costs resulting from DEP's decisions to uneconomically commit each of its coal plants during the test year. I discuss how these costs will be imposed on DEP ratepayers if approved for recovery in this proceeding.

In Section 5, I evaluate the actual fuel and other production costs incurred by DEP (which, if determined to be reasonable and prudently incurred, would normally be passed on to ratepayers) to operate its coal-fired power plants during the test year. I evaluate the economic performance of DEP's coal units during the test period, and I compare the total average production cost of DEP units to those of other coal units around the country.

In Section 6, I discuss and evaluate the significant deviation between the total fuel cost incurred at each unit over the course of the test year (the average production cost) and the marginal cost of production used to make unit-commitment and dispatch decisions.

In Section 7, I outline recommended reporting requirements for future fuel charge adjustment dockets that will allow the Commission to evaluate whether the Company's unit-commitment practices are causing the Company to incur fuel costs unreasonably or imprudently. I recommend a disallowance of the $1.4 million in excess fuel costs incurred by DEP as a result of uneconomic commitment decisions.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. DEP regularly committed its coal units at Mayo and Roxboro at times when it would have been less costly to serve retail ratepayers with other resources, as explained in Section 4. In each instance, the Company incurred excess fuel costs (above what it would have paid to operate lower-cost units on its system) which it seeks to recover from ratepayers in this docket.

2. During the test period, DEP's coal units had some of the highest fuel costs among all coal units in the country, yet DEP continued to incur costs in operating and maintaining the units. As explained in Section 5, Mayo and Roxboro ranked in the top 82nd and 83rd percentile, respectively, for most expensive fuel costs in 2020 among all coal-fired power plants in the United States.
3. DEP's reported average cost of generation at Mayo and Roxboro exceeded the reported cost of the marginal unit on the Company's system (system lambda) during nearly every month of the test year, as explained in Section 5. In total, during the test year, DEP incurred $103.0 million in fuel and variable costs above what the Company should have had to pay to serve the last MWh of load on its system in every hour.
4. The marginal production costs that DEP used to make unit-commitment decisions omitted approximately half of the actual or average fuel and variable costs that the Company incurred to operate its coal units during the test year. As discussed in Section 6, this omitted portion amounted to $157.5 million worth of fuel and other variable costs, approximately $147.7 million of which is fuel costs. This omission resulted in DEP committing and dispatching its coal units significantly more often than if the Company had based its commitment decisions on the actual fuel and variable costs incurred to operate each unit.

5. Even with less than half the actual fuel and variable cost reflected in the marginal production cost that it used to make its unit-commitment decisions during the test year, DEP's unit-commitment practices at its coal plants caused the Company to knowingly incur over $1.4 million in excess fuel costs at Mayo and Roxboro, as discussed in Section 4. That represents the excess fuel costs that DEP incurred at Mayo and Roxboro during the months when DEP operated the units, despite its own data showing that doing so would incur excess fuel costs.
6. DEP did not adequately report and describe its fuel cost accounting and unit-commitment practices in its fuel charge adjustment application. The Company should have included documentation of its daily decision-making process and its reasoning for frequent uneconomic commitment, as discussed in Section 7.

Q Please summarize your recommendations.

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

1. I recommend that the Commission disallow $1.4 million in excess fuel costs incurred at Mayo and Roxboro as a result of imprudent commitment decisions. This represents the fuel costs incurred in excess of what the Company would have paid for fuel had it instead committed its lower-cost units that were available at the time.

2. DEP should be required to make its marginal and average production costs fully transparent to the Commission and parties. Specifically, DEP should provide a full breakdown of the following, accompanied by a detailed explanation of each and full work papers that show how each component was calculated:
    a. Full production cost of each unit that will be passed on to ratepayers in this docket, broken down into fixed and variable costs. Variable costs should further be broken down by fuel, reagents/by products, emissions, and variable operations and maintenance ("O&M").
    b. Marginal production cost of each unit used for making unit-commitment and dispatch decisions, broken down by the same components listed directly above. For any production costs excluded from DEP marginal production costs, the Company should provide a detailed justification for why these costs are not relevant for making unit-commitment decisions.
3. The Commission should require DEP to provide a detailed report describing its daily unit-commitment decisions and practices as part of future fuel clause adjustment proceedings. DEP should provide the following information as part of each fuel clause adjustment application, to inform the Commission's review of its unit-commitment practices and

determination whether DEP's fuel and fuel-related costs for those units were reasonably and prudently incurred:

a. All 7-day forecast sheets that show the cost data for every unit on the system that the Company used to develop the Company's daily unit-commitment decisions.

b. The reason for any deviation between the commitment decision suggested by the Company's forward-looking price-based analysis and the Company's actual commitment decision (e.g., where the Company's analysis suggests that a unit has a production cost above the marginal system cost during a given day, and the Company self-commits the unit anyway).

c. Hourly data sufficient for the Commission to calculate the actual costs incurred to operate each unit in each test-year period, including total unit generation, delivered fuel cost, marginal or "replacement" fuel cost, total variable O&M cost, system lambdas, day-ahead commitment status, and actual outages.

4. Given the low capacity factor at which DEP's coal fleet operated during the test period, the Company should evaluate moving some of its plants to seasonal operation and retiring some of its units.

3. VERTICALLY INTEGRATED UTILITIES IN NON-CENTRALIZED MARKETS, SUCH AS DEP, CONTROL AND COORDINATE THE COMMITMENT AND DISPATCH OF THEIR COAL-FIRED GENERATING UNITS

Q Please explain the terms "unit commitment" and "dispatch."

A Unit commitment is the process by which a utility decides if a long-lead-time generating unit, such as a coal-fired power plant, should be operational for the following day. Commitment is the decision to either keep the unit online, bring a unit online that is not currently generating, or bring offline ("de-commit") a unit that is currently online. Unit-commitment decisions are distinct from "dispatch" decisions, which are the decisions to incrementally increase or decrease a unit's generation. Fast-start units like combustion turbines or battery storage can generally be dispatched from idle (or "blackstart") and do not need to be committed ahead of time. However, large steam boilers require advanced commitment, and once committed to operate, must run at a minimum level of output.

Q How does the process of unit commitment occur?

A The process of unit commitment requires that the operator look forward to determine if a unit is likely to operate economically over the next few days. To make this determination, the operator will compare the costs of starting and operating a particular unit with the costs of all other units on its system to determine whether that unit should be online the next day. When a unit is committed economically, the unit's marginal cost of production is reasonably expected to be lower cost than the marginal cost of energy, called "system lambda," over the next day or days. When a unit is committed uneconomically, the operator has decided to operate that unit at its economic minimum (the lowest MW output that a unit can safely and efficiently maintain) even though that unit's marginal costs of production are projected to be higher than the system lambda. When the full production cost of a unit is higher than other available resource options, incurring that unit's fuel costs may not be reasonable or prudent.

Q Please describe how dispatchable power plants are generally committed and operated by electric utilities like DEP that operate outside of organized wholesale markets.

A In a non-centralized market, the utility is responsible for internally committing and dispatching its units and procuring energy through bilateral trades when needed. These utilities generally rely on internal processes that project the marginal production cost to operate each unit. Resources are committed based on marginal cost, with the lowest-cost resources coming online first, and progressively more expensive units being turned on until system load is met. The last unit needed to meet system load sets the system marginal cost (the system lambda). The unit-commitment and dispatch processes should be based on economics and should generally ensure customers are served by the lowest-cost resources while maintaining reliability.

Q In practice, are all power plants actually committed by electric utilities in that way?

A No. While some utilities do adhere closely to efficient dispatch and commitment, others do not and can exhibit a wide discrepancy between the cost of operation and operational decision, as is seen with DEP. Utilities may ignore marginal cost when making operational decisions or simply consider only a portion of the unit's actual cost in making commitment and dispatch decisions. The result is that units may be brought or kept online when they would otherwise not operate because lower-cost resources are available to serve load.

Q Should a utility always commit its units to minimize costs to ratepayers based purely on the basis of marginal costs?

A Not necessarily. There are limited circumstances in which a unit needs to be operated out of merit. For example, sometimes units need to be brought or kept online for testing purposes or in anticipation of a reliability need. These decisions may be made regardless of costs. Aside from these exceptions, utilities are expected to use accurate cost information and robust processes to make commitment decisions. But they are not expected to always be right when circumstances deviate from what they projected.

Given the inflexibility of coal units, it can sometimes make sense to leave a unit online for short periods of time, even when there are lower-cost resources available, in order to be available to provide electricity during hours of high demand. But even so, the unit must be projected to be economic overall across a multi-day or week period of time.

Additionally, if system demand or the availability (or cost) of alternative energy opportunities differs significantly from what the utility projected, the utility's commitment decisions may not minimize costs to ratepayers during a multi-day period. If the utility's own contemporaneous analysis indicated that operating the unit would minimize costs, it is not necessarily an imprudent decision. But, if the high costs are part of a pattern in which the utility's forecast is consistently and systematically wrong and the utility has neglected to modify its decision-making process, the entire process may not be robust or prudent. The accuracy of the utility's daily unit-commitment decision-making process should itself be fed back into its decision-making process, with modifications incorporated when the current process is falling short.

Q What does it mean to operate a unit "out of merit" or "uneconomically"?

A When a utility operates a unit without regard for the unit's marginal cost, the unit is said to be committed "out of merit" order. This is generally done by the utility applying a "must-run" status to the unit, thereby forcing the unit to operate with a power output no less than its minimum operating level no matter how the unit's operating economics compare to that of other units on the utility's system.

Ratepayers incur the fuel and variable costs to operate the unit, regardless of whether there were lower-cost resource options available to meet system needs.

This practice is common among investor-owned utilities such as DEP that are able to pass fuel costs directly on to ratepayers. It is much less common among merchant plants or independent power producers that operate within organized wholesale markets.[2] These operators rely entirely on market revenues to cover their units' operating and fixed costs. This provides a strong incentive to them to only commit their units when the market will cover the units' operating costs.

Q Please explain why investor-owned utilities would ignore or underrepresent unit costs when making commitment or dispatch decisions.

A First, for inflexible units with long start-up and shut-down times, such as coal-fired power plants, utilities regularly force units to stay online in order to avoid unit cycling costs. Doing so can decrease wear-and-tear and resulting maintenance costs,[3] but it also generally results in the incurrence of unnecessary

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[2] *See, for example,* Playing with Other People's Money. Sierra Club, October 2019. Accessible at https://www.sierraclub.org/sites/www.sierraclub.org/files/Other%20Peoples%20Money%20Non-Economic%20Dispatch%20Paper%20Oct%202019.pdf.

[3] *See* Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices. NARUC, January 2020. Accessible at https://pubs.naruc.org/pub/7B762FE1-A71B-E947-04FB-D2154DE77D45.

operational costs well in excess of the cycling costs being avoided. But this practice is unnecessary because cycling times and costs can be, and in fact are, incorporated into utilities' multi-day unit commitment decision-making processes (as DEP does).[4]

Second, in order to address fuel over-supply issues, utilities may artificially lower the marginal cost of a unit for the purposes of keeping a unit online to burn excess fuel. This is generally done when it is cheaper to burn the coal at a loss than to store the coal or cancel a fuel contract. Duke Energy Indiana refers to this process as a "coal price decrement."[5]

Third, fuel or transportation contract structure and utility judgement about incurrence of O&M costs drive the categorization of utility costs as either fixed or variable. Utilities generally exclude costs associated with fixed transportation contracts (as DEP is doing here), fixed tonnage requirements, or must-take provisions of fuel contracts from unit dispatch and commitment decisions. This practice effectively locks ratepayers into paying a portion of fuel costs, often without any formal approval from the regulatory commission. Utility judgement

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[4] Duke Energy Progress Response to Sierra Club Request 1-9 (d).

[5] Direct Testimony of John Swez, IURC Cause No. 38707-FAC 125. Accessible at https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/d333ff64-9cd5-ea11-a813-001dd8018921/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=38707%20FAC%20125%20DEI%20Direct%20Testimony%20of%20John%20D%20Swez.pdf.

of which O&M costs are truly variable and predictable based on unit operations and which are truly fixed also varies widely.

Q Are there any reasons why a utility might be incentivized to operate a unit more often than it should be from a cost perspective?

A Yes. A utility that receives a return of and on assets in the rate base may have an incentive to show that aging units are still "used and useful" despite the substantial capital and fixed expense required to keep them online. A unit that is not economic over the long run (relative to replacement options) and does not provide economic service on a short-term basis may be perceived as not used or useful and at risk for disallowance. As noted by the U.S. Energy Information Administration ("EIA"), coal units that move to very low utilizations are often retired shortly thereafter because the justification for their operational costs evaporates.[6]

4. DEP INCURRED $1.4 MILLION IN AVOIDABLE FUEL COSTS AT ITS COAL PLANTS AS A RESULT OF UNECONOMIC UNIT-COMMITMENT DECISIONS DURING THE TEST YEAR

Q Please summarize this section.

A In this section I review the marginal cost of production that DEP uses for the purposes of making unit-commitment and dispatch decisions. DEP's reported marginal cost of production at its coal plants is far lower than its average cost of

[6] U.S. Energy Information Administration. 2020. "As U.S. coal-fired capacity and utilization decline, operators consider seasonal operation." *Today in Energy*. September 1, 2020. Accessible at https://www.eia.gov/todayinenergy/detail.php?id=44976.

production as a result of the Company inappropriately excluding certain variable costs. Nonetheless, I found that the Company incurred over $1.5 million in avoidable variable costs at its coal plants as a result of its uneconomic unit-commitment practices during the test year, $1.4 million of which were fuel costs. In other words, even accepting the Company's erroneous characterization of its marginal cost of production, DEP is still incurring avoidable fuel costs that it seeks to pass on to ratepayers.

Q Describe DEP's coal-fired power stations.

A The Company has two coal-fired power stations: Mayo and Roxboro. Mayo consists of a single unit and has a total capacity rating of 738 MW. Roxboro consists of four units (Units 1-4) and has a total capacity rating of 2,462 MW.[7]

Q Please describe the different categories of costs incurred at DEP's coal plants, what costs are included in each category, and which costs are recovered in the annual fuel clause adjustment proceedings such as the current docket.

A Table 1 provides a breakdown of all the major categories of forward-looking costs incurred by DEP at its coal plants and indicates which DEP requested to be recovered in this docket. The marginal cost of production—that is, the incremental cost of operating the unit—is composed of a subset of variable costs:

[7] DEP, Application in the Fuel Charge Adjustment Proceeding. Exhibit 6.

the replacement cost of fuel, which is the "market price of fuel plus variable transportation costs,"[8] and the cost of reagents/byproducts, emissions, and variable O&M. DEP utilizes the marginal cost of production when making a unit-commitment decision. I discuss the marginal cost of production in this section.

Importantly, the marginal cost of production does not represent the actual or average production costs passed on to ratepayers. The actual cost of production is composed of fixed costs, which are incurred regardless of whether and how a unit is operated, and variable costs, which are incurred based on usage. Variable costs include the cost of the fuel that was actually burned (or paid out) and all associated transportation costs, regardless of contract structure. Reagent / byproduct, emissions, and variable O&M costs are also included. The average production cost provided by the Company in this docket is calculated by adding up all fuel and other variable costs incurred to operate each unit and spreading them out over the unit's total MW output.

[8] Duke Energy Progress Response to Sierra Club Request 1-9.

Table 1: Categories of coal plant costs used for unit commitment, included in actual / average production cost, and recovered in current docket

Item	Cost used in Duke's unit-commitment process (marginal production cost)	Cost included in actual / average production cost	Cost for recovery in current fuel docket
Fuel			
Fuel	Market / replacement cost of fuel	Cost of actual fuel inventory	Cost of actual fuel inventory
Fuel Transportation			
Barge transport for coal	Full cost	Full cost	Full cost
Rail transport for coal	Only variable component	Full cost (fixed and variable)	Full cost (fixed and variable)
Non-operations and maintenance variable costs			
Reagents/byproduct	Full cost	Full cost	Full cost
Emissions	Full cost	Full cost	Full cost
Operations and Maintenance (O&M)			
Variable O&M	Full cost	Full cost	None
Fixed O&M	None	None	None
Other forward-looking fixed costs			
Sustaining capital expenses	None	None	None
Taxes	None	None	None
Other fixed plant costs	None	None	None

Q How does DEP operate its system?

A DEP operates its system with Duke Energy Carolinas based on the terms of a Joint Dispatch Agreement.[9] The Fuels and Systems Optimization Portfolio Management group is responsible for developing a unit-commitment plan (that is

[9] DEP Response to Sierra Club Request 1-32, Attachment SC 1.32 Joint Dispatch Agreement.

deciding which units to turn on or keep online). The Energy Control Center is responsible for operating and economically dispatching the Company's generation resources.[10] In deciding which units to commit and dispatch, the Company calculates the marginal production cost for each unit based on the market replacement cost of fuel, reagents/byproduct costs, emissions, and other variable O&M costs incurred at that particular unit.[11]

Q What tools does DEP have to inform its unit-commitment decisions?

A DEP conducts cost-based forward-looking analysis every day using unit-commitment modeling software called GenTrader.[12] Forecasted customer demand, fuel and emission market prices, contractual obligations, unit costs and parameters, and planned unit outage information are all input into the model. The model outputs "a unit commitment plan that is utilized to dispatch the generation fleet to minimize production costs while ensuring reliability over the 7-day forecast period."[13] The Company adjusts the analysis throughout the day as needed. I will refer to this analysis as the "7-day forecast."[14]

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[10] DEP Response to Sierra Club Request 1-6.
[11] DEP Response to Sierra Club Request 1-9 and 1-10.
[12] DEP Response to Sierra Club Request 1-10.
[13] *Ibid.*
[14] In Indiana, Duke Energy produces a 7-day forecast known as the P&L or Profit and Loss Analysis.

Q How should DEP be using the results of its cost-based analysis to inform unit-commitment decisions?

A Except in the case of unit testing or other extenuating circumstances, DEP should elect to commit its units only if it expects the unit to operate at below system lambda over a reasonable near-term time period (the Company's 7-day forecast period would be a reasonable time-period), incorporating consideration of reliability as well as start-up and shut-down costs and times. Conversely, the Company should take a unit offline if the Company projects it will operate at a cost that exceeds system lambda. Operating the units above system lambda would predictably result in higher costs that could have been avoided. Therefore, the Company should document any deviations between its final commitment decision and the commitment plan based on its 7-day forecast.

Q Is there evidence that DEP is committing its coal units uneconomically?

A Yes. The Company's data from GenTrader provided in discovery[15] shows that the Company operated its units during many sustained periods of time when its own data showed that it would be less expensive to operate other units on a marginal

[15] DEP Response to Sierra Club Request 1-3a, Attachment 2021 DEP SC DR 1.3a_d_e_j CONFIDENTIAL DEP Coal Unit Fuel Detail; DEP Response to Sierra Club 1-3b, Attachment 2021 DEP SC DR 1.3b CONFIDENTIAL DEP INCDEC_System Lambda Prices by day by hour.

production cost basis. In these hours, the Company incurred excess costs that it now seeks to pass on to ratepayers.

Q Why is it concerning that DEP is committing its coal units out of merit order so frequently during the test-year period?

A Operating units out of merit order incurs unnecessary fuel and variable operational costs that are passed on to ratepayers. It is understandable that DEP may incur operational costs in excess of system marginal costs on a daily or even weekly basis and incur excess costs in a few hours of the day or week in order to be online during peak hours. But it is not reasonable or prudent for DEP to operate a unit at a cost that exceeds the system marginal cost over a sustained period of time. Excess costs incurred as a result of this operational decision are avoidable through better unit-commitment decisions and indicate that DEP is either (1) not using robust and complete input data to inform its unit-commitment decisions, or (2) ignoring the results of its unit-commitment analysis. These costs were likely avoidable if the units were instead committed and dispatched based on economics.

In addition, when a unit is committed out of merit, it shows up on the supply curve as a zero- or low-cost resource, but ratepayers still incur the full cost to operate the resources. By showing up as a zero- or low-cost resource, these out of merit coal units cut the line and displace lower-cost resources that were previously below the margin. This has a price suppressive effect and results in a system lambda that is below the marginal cost of energy on DEP's system. The coal unit is still operating above system lambda and those full unit costs are being passed on to ratepayers. Beyond the direct ratepayer impact, this has important implications for how avoided costs are calculated.

Q Did you identify avoidable excess costs based on your analysis?

A Yes, as shown in Table 2, I find that during the test year, DEP could have avoided at least $1.5 million in excess costs at its coal plants if the Company had made better unit-commitment decisions based on just the marginal cost it uses for the purposes of unit commitment and dispatch. Specifically, these are the costs that were avoidable if DEP had turned its coal units off in the months during which each unit's production costs exceeded the system's marginal cost and instead used its lower-cost resources to meet system needs. Of the excess $1.5 million in costs, $1.4 million represents excess fuel costs.[16]

[16] DEP Response to Sierra Club Request 1-3(a), 2021 SC DR 1.3a_d_e_j CONFIDENTIAL DEP Coal Unit Fuel Detail; DEP Response to Sierra Club request 1-3(b), 2021 SC DR 1.3b CONFIDENTIAL DEP INCDEC_System Lambda Prices by day by hour.

Table 2: Operational costs in excess of system lambda

Plant	Avoidable Operational Costs ($000)
Mayo	[redacted]
Roxboro	
Total	**$(1,527)**

Source: DEP Response to Sierra Club Request 1-3(a), 2021 SC DR 1.3a_d_e_j CONFIDENTIAL DEP Coal Unit Fuel Detail; DEP Response to Sierra Club request 1-3(b), 2021 SC DR 1.3b CONFIDENTIAL DEP INCDEC_System Lambda Prices by day by hour.

Q On what do you base your determination that the costs incurred during the test year months when unit costs exceeded system marginal costs are avoidable?

A DEP produced hourly data with "modeled" unit costs, system load for just DEP's part of the system, and actual system lambdas. Although the modeling occurs after the fact,[17] the modeled unit costs represent the cost information that the Company had at the time it made its unit-commitment and dispatch decisions. Any time the unit costs were projected to exceed system lambda (inclusive of start-up cost considerations) over a multi-day stretch, a responsible utility manager would reduce costs to ratepayers by shutting the units down.

Sierra Club requested the contemporaneous documentation that DEP produced at the time the Company made its daily unit-commitment decisions with all unit costs on the system, but the 7-day forecast sheets the Company provided had no cost information.[18] Without the contemporaneous documentation, the

[17] DEP Response to Sierra Club Request 3-2.

[18] DEP Response to Sierra Club 1-9(b); Duke Energy Progress Response to Sierra Club Request 3-1.

Commission will lack information critical for assessing the reasonableness and prudence of the Company's daily unit-commitment decisions.

5. DEP'S COAL PLANTS OPERATED AT AN AVERAGE PRODUCTION COST THAT EXCEEDED THE MARGINAL SYSTEM COST FOR NEARLY ALL OF THE TEST YEAR

Q Please summarize this section.

A In this section, I review the actual generation costs that were passed on to ratepayers as a result of DEP's operation of its coal-fired units during the test period. I find that both of the Company's coal-fired power plants operated at an average production cost that exceeded the marginal system cost during nearly every month in the test period.

Q How does the analysis in this section differ from the analysis presented in Section 4 above?

A In Section 4, I relied on DEP's characterization of its marginal cost of production at its coal plants, which is far lower than its average costs of production discussed in this section. I evaluated the hourly data, projections, and analysis that DEP modeled to inform its unit-commitment decisions.[19] I calculated the excess costs DEP predictably incurred by operating its units during periods when its own

[19] DEP Response to Sierra Club Request 1-3a, Attachment 2021 DEP SC DR 1.3a_d_e_j CONFIDENTIAL DEP Coal Unit Fuel Detail; DEP Response to Sierra Club 1-3b, Attachment 2021 DEP SC DR 1.3b CONFIDENTIAL DEP INCDEC_System Lambda Prices by day by hour.

projections showed it would incur operational costs in excess of system marginal cost.[20] Because the process of unit commitment and dispatch is necessarily forward-looking, Section 4 focused on DEP's projected costs.

In this section, I present analysis on how DEP's units *actually* performed during the test-year period using data available after the fact (*i.e.,* the average cost of generation[21] that DEP incurred by operating its coal units uneconomically rather than turning them off). I show the total excess costs that DEP seeks to pass on to ratepayers during the months where the unit's average production costs exceeded the average system lambda.[22]

Q Describe Duke's utilization of its coal-fired fleet during the test period.

A Between April 2020 and March 2021, each of DEP's coal-fired power plants was minimally utilized. Specifically, every unit had an annual capacity factor below 37 percent, as shown in Table 3.[23]

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[20] DEP Response to Sierra Club 1-3b, Attachment 2021 DEP SC DR 1.3b CONFIDENTIAL DEP INCDEC_System Lambda Prices by day by hour.

[21] DEP Response to Sierra Club 1-3f,j, Attachment 2021 DEP SC DR 1-3f_j DEP Monthly Accounting Fuel Cost_Burn Detail.

[22] DEP Response to Sierra Club 1-3b, Attachment 2021 DEP SC DR 1.3b CONFIDENTIAL DEP INCDEC_System Lambda Prices by day by hour.

[23] DEP Response to Sierra Club 1-3a, 2021 SC DR 1.3a_d_e_j DEP Coal Unit Fuel Detail; DEP, Application in the Fuel Charge Adjustment Proceeding, Exhibit 6.

Table 3: Test Period Annual Capacity Factors for DEP Coal Units

Unit	Test Period Capacity Factor (%)
Mayo	17.8%
Roxboro 1	25.6%
Roxboro 2	37.0%
Roxboro 3	34.3%
Roxboro 4	21.4%

Source: DEP Response to Sierra Club Request 1-3(a), 2021 SC DR 1.3a_d_e_j CONFIDENTIAL DEP Coal Unit Fuel Detail; DEP Application in the Fuel Charge Adjustment Proceeding (Exhibit 6).

Q Please summarize your analysis of the economic performance of DEP's units during the test year based on the Company's actual cost data.

A I compared the hourly system lambdas[24] to the monthly average cost of generation reported by DEP at each plant.[25] As shown in Table 4, I found that during the test period of April 1, 2020, through March 31, 2021 the average cost of generation at each coal station was higher than the average system lambda during the hours that plant was online. That means that in every month during the test year, nearly all of DEP's coal-fired power plants were operating at an average cost above the marginal cost of electricity on its system, when there were lower-cost resources available to serve load.

In making the decision to commit its coal units, DEP omitted nearly half of its fuel costs from the GenTrader modeling analysis. This means the marginal

[24] DEP Response to Sierra Club 1-3b, Attachment 2021 DEP SC DR 1.3b CONFIDENTIAL DEP INCDEC_System Lambda Prices by day by hour.

[25] DEP Response to Sierra Club Request 1-3f, Attachment 2021 DEP SC DR 1.3f_j CONFIDENTIAL DEP Monthly Accounting Fuel Cost_Burn Detail.

generation cost used by GenTrader software to make daily unit-commitment decision represents only half of the Company's actual incurred fuel costs. In total, DEP incurred $103.0 million in excess production costs by operating its coal units to meet load relative to the cost it should have incurred to meet load based on its reported system lambda (as discussed in Section 6).

Table 4: CONFIDENTIAL Average cost of generation relative to average system lambda

Year	Month	Coal-generation-weighted system lambda during hours DEP coal plants are online ($/MWh)	Average coal station cost of generation ($/MWh)	
			Mayo	Roxboro
2020	4	[redacted]	[redacted]	[redacted]
2020	5	[redacted]	[redacted]	[redacted]
2020	6	[redacted]	[redacted]	[redacted]
2020	7	[redacted]	[redacted]	[redacted]
2020	8	[redacted]	[redacted]	[redacted]
2020	9	[redacted]	[redacted]	[redacted]
2020	10	[redacted]	[redacted]	[redacted]
2020	11	[redacted]	[redacted]	[redacted]
2020	12	[redacted]	[redacted]	[redacted]
2021	1	[redacted]	[redacted]	[redacted]
2021	2	[redacted]	[redacted]	[redacted]
2021	3	[redacted]	[redacted]	[redacted]

Source: DEP Response to Sierra Club request 1-3(b), 2021 SC DR 1.3b CONFIDENTIAL DEP INCDEP_System Lambda Prices by day by hour; DEP Response to Sierra Club Request 1-3(f), 2021 SC DR 1.3f_j CONFIDENTIAL DEP Monthly Accounting Fuel Cost_Burn Detail.

Q Does the analysis reflected in Table 4 represent the total costs incurred by ratepayers as a result of DEP operating and maintaining its coal plants?

A No. The monthly average cost of generation displayed in Table 4 was provided by the Company and is composed of actual fuel and variable operating expenses, including all transportation expenses. The data in Table 4 simply show whether the units pass the lowest bar of providing value to ratepayers on an hourly basis. It says nothing about whether the plant is the lowest-cost resource available to serve customer load relative to alternatives resource options over a longer time horizon. This type of comparison requires consideration of the full forward-going costs, both fixed and variable and including sustaining capital expenditures, required to keep the plant operational. A full unit economic analysis of this type was presented by my colleague Rachel Wilson in Docket No. E-7, Sub 1214.

Q Do the coal units "pass the lowest bar of providing value to ratepayers on an hourly basis"?

A According to the values reported by the Company, no.

Q How do the fuel costs at DEP's coal units compare to those of other coal plants across the country?

A Mayo and Roxboro have some of the highest fuel costs among coal plants in the country.[26] Specifically, as shown in Table 5, the coal used at Mayo cost \$2.62/MMBtu and the coal used at Roxboro cost \$2.55/MMBtu during 2020. This puts these plants in the 83rd and 82nd percentile of most expensive solid fuel in the country. Mayo, for example, has a fuel cost higher than 83 percent of comparable

[26] Author's calculation from EIA Form 923, 2020.

coal plants nationwide. Roxboro is more expensive than 82 percent of comparable plants nationwide.[27]

Table 5: DEP's coal unit costs relative to other solid-fuel plants in the United States in 2020

Plant	Fuel Cost ($/MMBtu)	Percentile of most expensive solid-fuel plants
Mayo	$2.62	83%
Roxboro	$2.55	82%

Source: EIA Form 923 for 2020.

6. DEP EXCLUDED OVER 46 PERCENT OF THE PRODUCTION COSTS INCURRED AT ITS COAL UNITS FROM ITS UNIT-COMMITMENT AND DISPATCH DECISION-MAKING PROCESS

Q Please summarize this section.

A In this section I compare the production costs that DEP seeks to pass on to ratepayers, the marginal production costs DEP models in making its daily unit-commitment and dispatch decisions, and DEP's marginal system cost. I show how DEP excluded a significant portion of its production costs from its unit-commitment decisions.

Q Do you have any concerns with the unit-commitment data DEP has provided?

A Yes. DEP appears to exclude a significant portion of its actual fuel and variable operating costs from the marginal cost of production that it uses to make its unit-

[27] EIA Form 923, 2020.

commitment decisions. Specifically, the Company's reported marginal cost of production omits 46 percent of actual production costs incurred at its coal plants.[28]

The Company's marginal fuel costs represent the cost DEP would pay today to replace the fuel that it burns. DEP calculates the replacement cost of coal based on "market prices provided by independent 3rd party vendors, variable transportation costs associated with shipping the fuel from its suppliers to its coal stations, and byproduct/ reagent costs associated with emissions controls."[29] Actual fuel costs, however, represent the cost of the fuel that DEP actually uses for generation at each plant. The Company seeks to recover actual fuel expenses from ratepayers in this docket.

Q How large is the discrepancy between DEP's actual and marginal fuel costs?

A As shown in Table 6 below, during the test period DEP incurred $315.4 million in fuel and other production costs operating its coal fleet, but only $157.9 million in variable fuel and other operating costs were included in the Company's unit-commitment and dispatch modeling. This means that a full 46 percent of the

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[28] Analysis based on data from DEP Response to Sierra Club Request 1-3a, Attachment 2021 DEP SC DR 1.3a_d_e_j CONFIDENTIAL DEP Coal Unit Fuel Detail; DEP Response to Sierra Club 1-3b, Attachment 2021 DEP SC DR 1.3b CONFIDENTIAL DEP INCDEC_System Lambda Prices by day by hour; and DEP Response to Sierra Club Request 1-3f, Attachment 2021 DEP SC DR 1.3f_j CONFIDENTIAL DEP Monthly Accounting Fuel Cost_Burn Detail.

[29] Duke Energy Progress CONFIDENTIAL Response to Sierra Club Request 1-19.

Company's production costs, equaling $157.5 million, were excluded from DEP's unit-commitment and dispatch decision-making processes. As a result, Duke's unit-commitment modeling based on marginal production costs showed that its fleet provided a value of almost $54.5 million to its ratepayers during the test year,[30] but in fact the Company actually incurred $103.0 million in actual excess production costs relative to system lambda during the test year. Of the total excess production costs incurred, approximately 94 percent, or $96.6 million, represents fuel costs.

The $1.5 million in excess costs discussed in Section 4 above represents the portion of the $54.5 million in value that was incurred during just the subset of months where a coal unit was on net more expensive to operate than system lambda during the hours that each unit operated. In other words, over the course of the year, the Company calculated that its coal units provide $54.5 million in value from operating based on each unit's marginal unit costs, but during the unit's poorest performing months, the Company actually calculated that $1.5 million in excess costs would be incurred from operating the units. These costs were fully avoidable if the units had been turned off during those specific months and lower-cost units had been used instead.

[30] At all units, except Roxboro 4 which was offline, over half of the projected value for the test year is attributed to the polar vortex weeks in February 2021. At Mayo, nearly 95 percent of the annual projected value is attributed to the polar vortex weeks.

Table 6: Total Production Costs incurred by DEP's Coal Fleet during the test year

Cost Description	($Million)	Source
a. Total actual /average production costs passed on to ratepayers	$315.4	Average cost of generation from DEP in SC 1.3(f_j)
b. Marginal costs used by DEP for the purpose of making unit-commitment and dispatch decisions	$157.9	Modeled unit variable costs from DEP in SC 1.3(a_d_e_j)
c. Total cost of serving load met by coal units at system lambda	$212.4	System lambda from DEP in SC 1.3(b) x generation from SC 1.3(a_d_e_j)
e. Cost of generation omitted from DEP's unit-commitment and dispatch decision-making process	($157.5)	(b) - (a)
d. Difference between system lambda and DEP's marginal production cost	$54.5	(c) - (b)
f. Actual excess costs incurred by DEP from operating its coal fleet during the test year that it seek to pass on to ratepayers	($103.0)	(c) - (a)

Source: DEP Response to Sierra Club Request 1-3(a), 2021 SC DR 1.3a_d_e_j CONFIDENTIAL DEP Coal Unit Fuel Detail; DEP Response to Sierra Club request 1-3(b), 2021 SC DR 1.3b CONFIDENTIAL DEP INCDEP_System Lambda Prices by day by hour; DEP Response to Sierra Club Request 1-3(f), 2021 SC DR 1.3f_j CONFIDENTIAL DEP Monthly Accounting Fuel Cost_Burn Detail.

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

A As discussed above, DEP makes unit-commitment decisions based on each unit's marginal production cost, also known as the incremental operating costs. Lower operating costs therefore put the unit lower on the supply curve and make it more likely that a unit will be committed. If the marginal production costs used for making unit-commitment decisions and market offer curves represent only a portion of the actual cost of fuel, then a unit will appear more economic than it actually is, and the unit will be over-committed and over-dispatched as a result.

Full (actual) fuel costs are still typically passed on to ratepayers either through the fuel charge adjustment process or through base rates (for the non-fuel variable component) regardless of what cost is used to make unit-commitment decisions. But these costs will be higher than if the plant were committed and operated based on its actual fuel cost. For this reason, the Commission should be concerned about which fuel costs the Company is using for different purposes and how those costs are calculated.

Q What accounts for the difference between DEP marginal and actual fuel costs at its coal plants?

A There are three main explanations for why certain operational costs (totaling $157.5 million) were excluded from DEP's unit-commitment decision-making process: (1) the Company's rail contracts currently include both fixed and variable costs; (2) the incremental cost of fuel is based on replacement fuel costs, not purchased fuel costs, which will be different; (3) the Company selected a buy-out for some of its coal contracts.

Q How are DEP's rail contacts structured?

A DEP indicated that its current rail transportation contracts include both fixed and variable costs.[31] DEP considers the fixed-cost component to be sunk and therefore excludes the component from its unit-commitment decisions.[32] DEP witness Verderame acknowledged that the current contract structure does not serve customers' interests, stating that "the current Fixed/Variable contract in place does not provide ongoing customer value in a declining burn environment."[33] Yet, DEP still operated its coal units with these costs excluded from its dispatch and commitment algorithms during the test year, and now seeks to recover the resulting excess fuel costs from its ratepayers.

The Company indicated that it is currently negotiating a new rail contract with 100 percent variable pricing.[34] Accounting for these rail costs as variable will increase the marginal production cost of DEP's units, closing the gap between the units marginal and actual production costs, and making alternatives even more attractive. Transportation costs account for approximately 40 percent of the DEP's delivered cost of coal.[35]

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[31] Duke Energy Progress Response to Sierra Club Request 1-25(a).
[32] Duke Energy Progress Response to Sierra Club Request 1-25(b).
[33] Direct Testimony of John Verderame, page 9.
[34] *Ibid.*
[35] *Id.* p 8.

Q Explain how the replacement cost of fuel differs from the actual cost of fuel?

A The incremental cost of fuel DEP models represents the replacement cost of fuel, not the cost the Company has paid for its current fuel supply. This difference is expected to be relatively small with DEP because the Company utilized a fuel procurement strategy whereby nearly [redacted] of its coal supply was procured through flexible and short-term coal contracts of two years or less.[36] With short-term contracts, the coal price in the contract and the replacement price the Company would pay on the spot market should not differ significantly, and the Company can more easily adjust its purchase based on need.

Q Explain the buy-out option that DEP selected for some of its coal contracts.

A DEP selected a buy-out option for some of its coal contracts instead of accepting delivery of the fuel and running the units for the purpose of burning off the coal. The Company's own analysis indicated that this option was projected to save

[36] Duke Energy Progress Response to Sierra Club Request 1-20, CONFIDENTIAL Coal Supply Contracts Summary attachment.

ratepayers [redacted] in 2020.[37,38] The [redacted] buy-out costs are included in the fuel costs passed on to ratepayers.[39]

Q How would DEP's system be impacted if the Company updated its marginal production costs to include underrepresented costs?

A If DEP updated its marginal costs to represent the actual production cost of each unit, its coal units would shift higher on the supply stack. This would make alternative resources more cost-competitive on an operational basis. As a result, the output of DEP's coal-fired units would be expected to decrease substantially. System lambdas would also likely increase to more accurately reflect the true system lambda. This increase in system lambdas may lead to an increase in the valuation of alternative new resources.

Q What do you conclude regarding the reasonableness of DEP's fuel management and unit-commitment decisions during the test period?

A It is reasonable to expect there will be a small difference between marginal unit costs and average unit costs based on (1) the delta between fuel and market prices at the time contracts were signed and the present, as well as truly unavoidable

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[37] Duke Energy Progress Response to PSDR 3-1, attachment 2021 DEP PSDR 3-1d CONFIDENTIAL Carolinas Decrement Analysis Exhibit 3 - Carolinas Coal Contracts Matrix (3-30-20).

[38] The Direct Testimony of J, Verderame, Page 6 lists the cost savings as $22 million. This appears to be the cost for DEC not DEP.

[39] Duke Energy Progress Response to PSDR 3-1, attachment 2021 DEP PSDR 3-1d CONFIDENTIAL Carolinas Decrement Analysis Exhibit 3 - Carolinas Coal Contracts Matrix (3-30-20).

fixed/sunk production costs. But a responsible utility manager should seek to minimize the portion of average costs that falls into these categories and are therefore omitted from the unit-commitment process. Specifically, this can be done by (1) securing fuel and transportation contracts that are flexible and have minimal locked-in or must-take provisions; (2) carefully reviewing the costs of fuel contracts relative to alternatives, including reduced operation and retirement of the plant, prior to signing any new fuel contracts; and (3) carefully reviewing O&M costs to break out the variable costs associated with predictive and preventative maintenance from those that are truly fixed.

7. Recommendations for the Commission

Q Please summarize your recommendations.

A I recommend that the Commission disallow $1.4 million in excess fuel costs incurred at Mayo and Roxboro as a result of imprudent commitment decisions. Additionally, I recommend that DEP provide more transparency and documentation on which costs it is using for the purposes of commitment and dispatch, and how it is making its daily unit-commitment decisions.

Q What do you recommend to address the discrepancy in production costs used to make unit-commitment decisions and the actual costs passed on to ratepayers?

A DEP should be required to provide full transparency into the Company's marginal and average production costs. Specifically, DEP should provide a full breakdown of the following, accompanied by a detailed explanation of each and full work papers that show how each component was calculated:

1. Full production cost of each unit that will be passed on to ratepayers in this docket, broken down into fixed and variable costs. Variable costs should further be broken down by fuel, reagents/by products, emissions, and variable O&M.
2. Marginal production cost of each unit used for making unit-commitment and dispatch decisions, broken down by the same components listed directly above. For any items not included in DEP marginal production costs, the Company should provide a detailed justification for why these costs are not relevant for making unit-commitment decisions.

Q What information do you specifically recommend that DEP provide in each fuel cost adjustment filing to allow a review of the prudence of its unit-commitment practices?

A The utility filings in this docket are insufficient and do not meet the filing requirements for this proceeding outlined in Commission Rule R8-55(e).[40] I recommend that DEP compile and file as workpapers with its annual fuel cost adjustment application a detailed report describing its daily unit-commitment decisions and practices as part of future fuel charge adjustment proceedings. DEP should provide the following information as part of each annual fuel charge

[40] NCUC Rule R8-55(e).

adjustment application, to inform the Commission's review of its unit-commitment practices and determination whether DEP's fuel and fuel-related costs for those units were reasonably and prudently incurred:

1. All 7-day forecast sheets that show the cost data for every unit on the system that the Company used to develop the Company's daily unit-commitment decisions.
2. The reason for any deviation between the commitment decision suggested by the Company's forward-looking price-based analysis and the Company's actual commitment decision (e.g., where the Company's analysis suggests that a unit has a production cost above the marginal system cost during a given day, and the Company self-commits the unit anyway).
3. Hourly data sufficient for the Commission to calculate the net value or excess costs that each plant actually incurred in each test-year period, including total unit generation, delivered fuel cost, marginal or "replacement" fuel cost, total variable O&M cost, system lambdas, day-ahead commitment status, and actual outages.

Q What other recommendations do you have for the Commission?

A I recommend that the Commission direct DEP to conduct a new retirement study of each unit in the Company's fleet. I acknowledge that the Company conducted retirement analyses for its 2020 Integrated Resource Plans at the direction of the Commission.[41] However, DEP should be required to evaluate the continued operation of each of its coal units based on economics, from both a short-term operational, and long-term planning perspective.

Q Are you recommending a disallowance in this docket relating to DEP's uneconomic commitment practices at any of its coal units?

A Yes. I am recommending a disallowance of $1.4 million. This represents the excess fuel costs that DEP incurred at the Mayo and Roxboro coal units as a result of sustained uneconomic operations during specific months. Specifically, the portion of fuel costs that DEP paid, above what it would have paid for fuel had it operated the lower-cost units available on its system. These excess fuel costs could have been avoided, had the Company economically committed its coal units.

Q Does this conclude your testimony?

A Yes.

[41] NCUC Docket No. E-100, Sub 165.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Devi Glick on Behalf of the Sierra Club – *Public Version* either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 31st day of August, 2021.

s/ Gudrun Thompson

Devi Glick, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-453-7050
dglick@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Principal Associate*, June 2021- Present; *Senior Associate*, April 2019 – June 2021; *Associate*, January 2018 – March 2019.

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Providing expert testimony in rate cases on the prudence of continued investment in, and operation of, coal plants based on the economics of plant operations relative to market prices and alternative resource costs.
- Providing expert testimony and analysis on the reasonableness of utility coal plant commitment and dispatch practice in fuel and power cost adjustment dockets.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents for expert report, public comments, and expert testimony.
- Evaluating utility long-term resource plans and developing alternative clean energy portfolios for expert reports.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017
Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.
- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.

- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

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TESTIMONY

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Public Utilities Commission of Nevada (Docket No. 21-06001): Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. August 16, 2021.

North Carolina Utilities Commission (Docket No. E-7, Sub 1250): Direct Testimony of Devi Glick in the Mater of Application Duke Energy Carolinas, LLC Pursuant to §N.C.G.S 62-133.2 and Commission Rule R8-5 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities. On behalf of Sierra Club. May 17, 2021.

Public Utility Commission of Texas (PUC Docket No. 51415): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to change rates. On behalf of Sierra Club. March 31, 2021.

Michigan Public Service Commission (Docket No. U-20804): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and factors (2021). On behalf of Sierra Club. March 12, 2021.

Public Utility Commission of Texas (PUC Docket No. 50997): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to reconcile fuel costs for the period May 1, 2017- December 31, 2019. On behalf of Sierra Club. January 7, 2021.

Michigan Public Service Commission (Docket No. U-20224): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan (Case No. U-20223) for the 12-month period ending December 31, 2019. On behalf of Sierra Club. October 23, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Surrebuttal Testimony of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 29, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Surrebuttal Testimony of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 21, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Direct Testimony and Exhibits of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 18, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Direct Testimony and Exhibits of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC125): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. September 4, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123 S1): Direct Testimony and Exhibits of Devi Glick in the Subdocket for review of Duke Energy Indian, LLC's Generation Unit Commitment Decisions. On behalf of Sierra Club. July 31, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC124): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. June 4, 2020.

Arizona Corporation Commission (Docket No. E-01933A-19-0028): Rely to Late-filed ACC Staff Testimony of Devi Glick in the application of Tucson Electric Power Company for the establishment of just and reasonable rates. On behalf of Sierra Club. May 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. March 6, 2020.

Texas Public Utility Commission (PUC Docket No. 49831): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

Nova Scotia Utility and Review Board (Matter M09420): Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power's Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Direct Testimony of Devi Glick regarding Southwestern Public Service Company's application for revision of its retail rates and authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

North Carolina Utilities Commission (Docket No. E-100, Sub 158): Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

State Corporation Commission of Virginia (Case No. PUR-2018-00195): Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petition to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

Connecticut Siting Council (Docket No. 470B): Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 12, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

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