STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 190

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)	**REDACTED DIRECT TESTIMONY OF R. BRENT ALDERFER AND IVAN URLAUB ON BEHALF OF CLEAN ENERGY BUYERS ASSOCIATION**

May 28, 2024

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I. Introduction of Panel.

Q: Mr. Alderfer, would you please state your name, position, and address?

A: Brent Alderfer. I am a founder and board member of New Energy Economics, a policy think tank offering analysis on energy policy options and the underlying economics of decarbonizing electricity generation. My address is 6312 Meetinghouse Rd, New Hope, Pennsylvania.

Q: On whose behalf are you testifying in this case?

A: New Energy Economics was asked by the Clean Energy Business Association (CEBA) to present testimony in this proceeding and I am testifying on CEBA's behalf.

Q: Please discuss your relevant experience, professional expertise, and educational background.

A: I served as a utility Commissioner on the Colorado Public Utilities Commission in the late 1990s.

After leaving the Commission, I founded and led a company, Community Energy, Inc., developing utility-scale wind farms across the country, concentrating in states that had no wind generation and leading that development as the economics of wind technology improved. We originated early wind projects with voluntary green pricing programs in partnership with 15 different utilities. In 2006, with about two gigawatts of wind projects under development, we sold the wind development company to Iberdrola, a Spanish utility and the largest owner of renewable energy at the time as it entered the U.S. market. I worked with Iberdrola, now Avangrid, for three years to complete the development of our wind projects as part of Iberdrola's expansion in the U.S.

Beginning in 2010, I led the transition to utility-scale solar at scale. We developed utility-scale solar for utilities and large corporate customers across the country early in the commercialization of that technology, bringing the price down to compete in competitive bidding for large-scale renewable generation. We developed several gigawatts of solar generation and with another ten gigawatts under development in December 2021, sold the solar development company to AES Corporation, a global diversified energy company.

I have no financial interest in any utility or in solar or wind project development.

I have a law degree from Georgetown University and practiced corporate and commercial law prior to entering the energy field as a Utility Commissioner. I have an electrical engineering degree from Northeastern University.

Q: Have you previously testified before this commission?

A: No.

Q: Mr. Urlaub, would you please state your name, position, and address?

A: Ivan Urlaub. I am Principal and founder of Urlaub Strategies LLC, a strategy consulting firm that collaborates with non-profit and private clients on resource economics, business strategy, equity, and carbon where they intersect with state, federal, and global policy and regulation. In a consulting capacity, I currently serve as Fractional Director, Energy & Infrastructure for New Energy Economics. My address is 104 Juniper Court, Carrboro, North Carolina.

Q: On whose behalf are you testifying in this case?

A: New Energy Economics was asked by CEBA to present testimony in this proceeding and I am testifying on CEBA's behalf.

Q: Please discuss your relevant experience, professional expertise, and educational background.

A: I served as Policy Director and Executive Director of the North Carolina Sustainable Energy Association (NCSEA) from 2005 to 2020. During my tenure with NCSEA, I served in numerous roles and capacities where I developed familiarity and understanding of North Carolina's electricity landscape, policy, regulation, consumer needs and behaviors, consumer energy burden, energy sector economics and issues, utility rate and program design, resource and transmission planning, project development, and public and private financing. I served as an advisor to state administrations of both parties in various energy planning processes, studies, and task forces.

I served two consecutive two-year terms as a Commissioner on the North Carolina Legislative Commission on Global Climate Change, appointed each time by the former Senate President Pro Tem. In my capacity with NCSEA, I collaboratively worked with stakeholders, decision-makers, clean energy industry members, large consumers and manufacturers, local governments, economic developers, University of North Carolina and community college systems, and utilities to design, negotiate, advocate for the adoption of, and measure the economic and rate impacts of dozens of approved North Carolina energy laws, regulatory decisions, and programs.

Most relevant to the complex and broad scope of the Carbon Plan and Integrated Resource Plan, I contributed to the design, negotiation, and measurement and evaluation of numerous North Carolina energy initiatives and North Carolina Utilities Commission (the Commission) rulings, including:

- The State's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) from 2005 to 2008;
- Development, bid evaluation, and awarding of the first RFP issued in 2006 by the NC Utilities Commission for producing a technical and economic study of RPS and EERS policy options that would require regulated utilities to utilize renewable energy and energy efficient resources, which informed development of the State's REPS law and rules;
- Model interconnection rules and the model net energy metering tariff, along with several of the subsequent modifications to those rules and related programs, from 2005 to 2014;
- The renewal and expansion of the state renewable energy tax credits in 2005, 2009, and 2010;
- The addition of energy efficiency into the NC Integrated Resource Planning rules adopted by the Commission in 2007-2008;
- Duke/Progress Save-a-Watt Program and subsequent introduction of shared customer savings (predating the Companies' merger);
- The first Green Source Rider that evolved into DEC's Green Source Advantage and more recent customer program iterations;
- A stipulation in the DEC 2018 rate case settlement that laid out the utility's financial and operational issues requiring resolution that led to DEC's recently approved entity-wide Tariffed On Bill program, offering its customers inclusive utility investment;

- The revision and expansion of energy performance contracting policy in 2005 and 2006 that has since resulted in about $2 billion of cumulative avoided state utility spending;
- Iterative improvements to the Roanoke Electric Cooperative's Pay As You Save program, supporting program goal attainment and expansion; and
- The design, capital funding, and delivery of the first utility assurance fund for inclusive utility investment programs, supporting utilities in North Carolina, Tennessee, and Arkansas.

Prior to my service with NCSEA, I started developing an applied understanding of economics and finance in resource management, conflict, and conflict prevention. Specifically, I supported the development of utility financial accounting systems, consumer willingness and ability to pay studies, tariff redesign, digital infrastructure and workforce development, debt refinancing, and resource planning efforts as part of USAID-funded efforts to resolve and prevent potential conflicts over natural resources across the Middle East and North Africa.

After leaving full-time employment with NCSEA in early 2020, I started a national strategy consulting business focused on energy, equity, and carbon. I currently collaborate with national non-profit and private sector clients in the areas of: energy economics and markets research and analysis; policy and regulatory analysis; design and standardization of inclusive utility investment programs and financial assurance mechanisms for utilities, lenders, and utility program participants; clean energy and climate technology business strategy; economic analysis for innovative clean energy technologies; and general client capacity building. As an Energy Security Fellow with Securing America's Future Energy in 2021, I focused on the impacts of geopolitics and global energy market dynamics on domestic energy markets, infrastructure, and resource planning, an expertise that I bring to my current advisory work.

I have a bachelor of arts degree from George Washington University in both Political Science and Environmental Studies. I have both a Master of Public Policy and a Master of Environmental Management degrees from Duke University. I also have an Energy Resilience Certificate from the George Washington University School of Engineering and Applied Science.

Q: Have you previously testified before this commission?

A: Yes. I testified in 2012 on behalf of NCSEA on the matter of the proposed merger of Duke Energy and Progress Energy.

II. <u>Background and Purpose of Testimony.</u>

Q: Mr. Alderfer and Mr. Urlaub, what is the background for your testimony?

A: The legislature mandated that the Commission take all reasonable steps to reduce emissions of carbon dioxide from electric generating facilities by 70% from 2005 levels in a least-cost manner by the year 2030 and achieve carbon neutrality by the year 2050.[1] The Commission issued an order requiring a consolidated Carbon Plan and Integrated Resource Plans (CPIRP or the Plan) to meet the carbon reduction goals with a Carbon Plan update

[1] House Bill 951 (S.L. 2021-165).

to its Integrated Resource Plan.[2] The Plan is expected to meet the carbon reduction goals "while minimizing the rate impacts to Duke ratepayers to the extent possible."[3]

Q: Has the Carbon Plan been filed?

A: Yes. Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) (collectively, Duke or the Companies) filed their CPIRP in August 2023 and a subsequent 2024 Supplemental CPIRP in January 2024 amending their underlying application. Duke proposes to make significant investments in natural gas generation to meet customer load. Duke made these proposals despite projecting a steady rise in natural gas prices and acknowledging that it will need to rely on natural gas delivered through constrained, proposed, and hypothetical interstate pipelines, along with future purchases of out-of-state gas supplies. Duke's preferred plan proposes to delay carbon reduction and rely on natural gas until small-modular and advanced nuclear reactors can be developed, tested, and made commercially available at economic rates.[4]

Q: In addition to future nuclear technology, does the Plan also rely on hydrogen as a replacement for natural gas?

A: Although the Plan states that new natural gas plants installed in the coming decade will be modified, and plants installed in the next decade will be designed, to burn hydrogen, the

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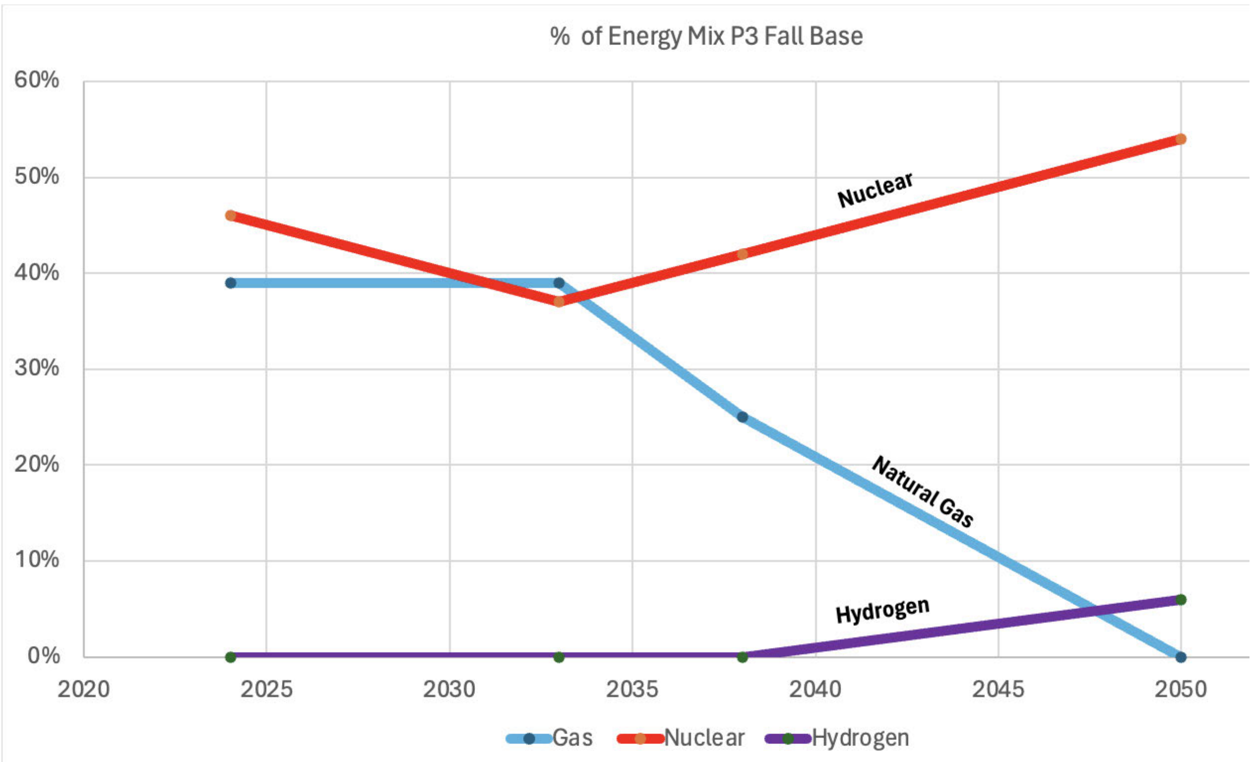
[2] Order Adopting Rule R8-60A and Amending Rules R8-60 R8-67 and R8-71, *Rulemaking Proceeding Related to Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)*, Docket E-100, Sub 191 (November 20, 2023).
[3] *Carbon Plan*, Public Staff of the North Carolina Utilities Commission, https://publicstaff.nc.gov/public-staff-divisions/energy-division/electric-section/carbon-plan (last visited May 23, 2024).
[4] *See* Verified Petition for Approval of 2023-2024 CPIRP, Executive Summary at 15; *See* Verified Petition for Approval of 2023-2024 CPIRP, Appendix J; Verified Petition for Approval of 2023-2024 CPIRP, Appendix E at 6, 12; Verified Amended Petition for Approval of 2023-2024 CPIRP, Supplemental Planning Analysis.

generation ramp-up curves in Figure 1 show that Duke does not actually plan to generate any significant amount of electricity from hydrogen even by 2050.[5]

Figure 1: Select Resources' Portion of Energy Mix (%) in P3 Fall Base



Q: How does the Plan propose to achieve carbon reductions?

A: As the Figure 1 curves show, the Plan proposes that increased nuclear generation will allow natural gas generation to ramp down starting in the late 2030s and into the 2040s. Apart from significant questions about commercialization of nuclear generation on that schedule, the economics of rate-based capital in new natural gas generation will lock in the use of natural gas for decades longer. Combined cycle gas turbines have a useful life of 25 to 30

[5] Figure 1 displays data from Verified Amended Petition for Approval of 2023-2024 CPIRP, Supplemental Planning Analysis at 39 (Table SPA 3-2).

years[6] (with some utilities claiming longer periods[7]). Assuming Duke intends full capital recovery for the new gas plants, the rate recovery for those assets would continue into the 2050s and 2060s.[8] If the Companies were to actually count on nuclear small modular reactors (SMR) and advanced reactors to replace natural gas beginning in the 2030s, most natural gas generation capacity would be significantly under-utilized and stranded well before the end of its useful life. Or, as one analysis found, ratepayers might be paying for worthless gas plants. [9]

Q: What is your conclusion from that overview of the Plan?

A: Our conclusion is that the Plan would lock the Companies into natural gas generation for several decades longer than Duke represents, and past the 2050 carbon neutrality deadline of 2050 set forth in HB 951.

Q: What is the purpose of your testimony?

A: The purpose of our testimony is to enumerate the significant risks and costs to ratepayers if Duke increases its reliance on natural gas for electric generation, as it has proposed to do. We describe the market forces and changing dynamics that will drive future natural gas prices and the volatility that will result in unavoidable runups and spikes in natural gas prices. We present examples of the magnitude of the costs to ratepayers from the runups and spikes that are inherent parts of natural gas supply markets, historically and going

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[6] Shravan Bhat and Ryan Foelske, *You Might Be Paying for a Worthless Gas Plant*, Rocky Mountain Institute (Apr. 18, 2022), https://rmi.org/you-might-be-paying-for-a-worthless-gas-plant/.
[7] Florida Power and Light, *Depreciation Analysis for Power Generation*, Florida Public Service Commission (Feb. 2016),
https://www.floridapsc.com/pscfiles/library/filings/2016/07554-2016/Support/OPCs%201st-38-Attachment%203.pdf.
[8] Bhat and Foelske, *supra* note 6.
[9] *Id.*

forward. Duke greatly underestimates resulting ratepayer costs in selecting a gas-heavy portfolio. The Commission should direct Duke in the near-term action plan to re-run its modeling using a more accurate representation of natural gas fuel cost and supply risk.

Accounting for the cost of gas price volatility makes it clear that the portfolios that best manage ratepayer costs and meet carbon reduction obligations include greater investment in fixed-price carbon-free resources, including solar, wind, battery storage, and demand-side resources. To mitigate cost-of-service and reliability risks, we urge earlier interconnection of fixed-cost carbon-free resources to meet the carbon goals in a least-cost manner and to minimize rate impacts to Duke ratepayers. This is particularly prudent and necessary in light of the load growth Duke describes from national onshoring policy, regional and state business expansion, and digital infrastructure growth.

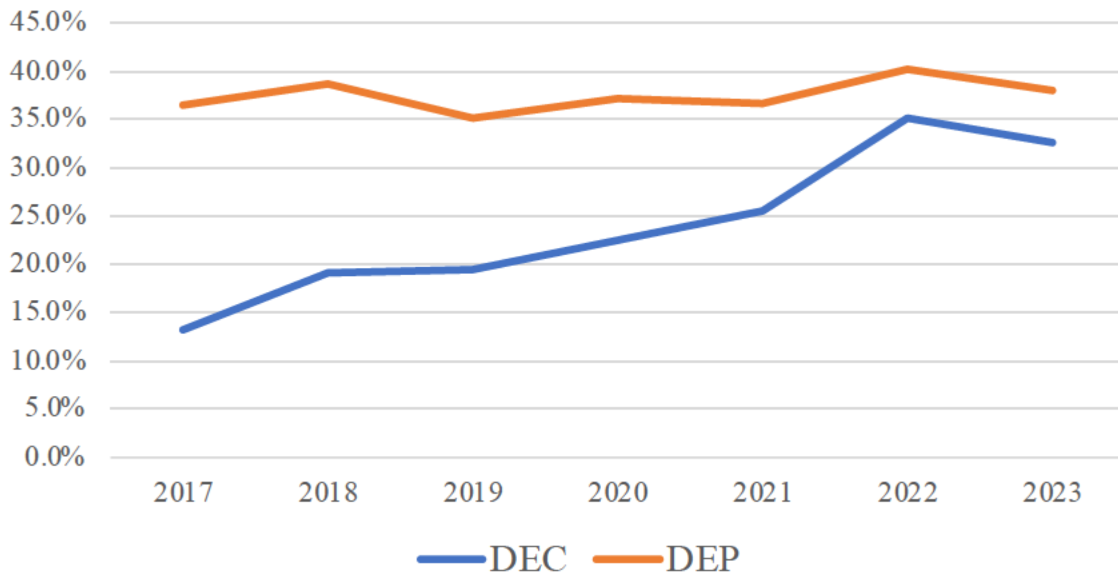
III. <u>The Cost of Duke's Increased Reliance on Natural Gas.</u>

Q: Has Duke been increasing its reliance on natural gas for electric generation?

A: Yes, Duke's reliance on natural gas has been steadily increasing. As shown below in Figure 2, DEC added significant natural gas generation from 2017 to 2023 such that natural gas went from under 15% of its generation portfolio to about 33%, almost bringing DEC in line with DEP, where natural gas comprises about 38% of system generation.[10]

[10] EQ Research LLC, The Role of Fuel Costs in Duke Energy's North Carolina's Retail Rates from 2017 Through March 2024 at 3 (Apr. 18, 2024).
Accessed at: https://www.edf.org/sites/default/files/documents/Issue_Brief_Narrative_4_22_24.pdf.

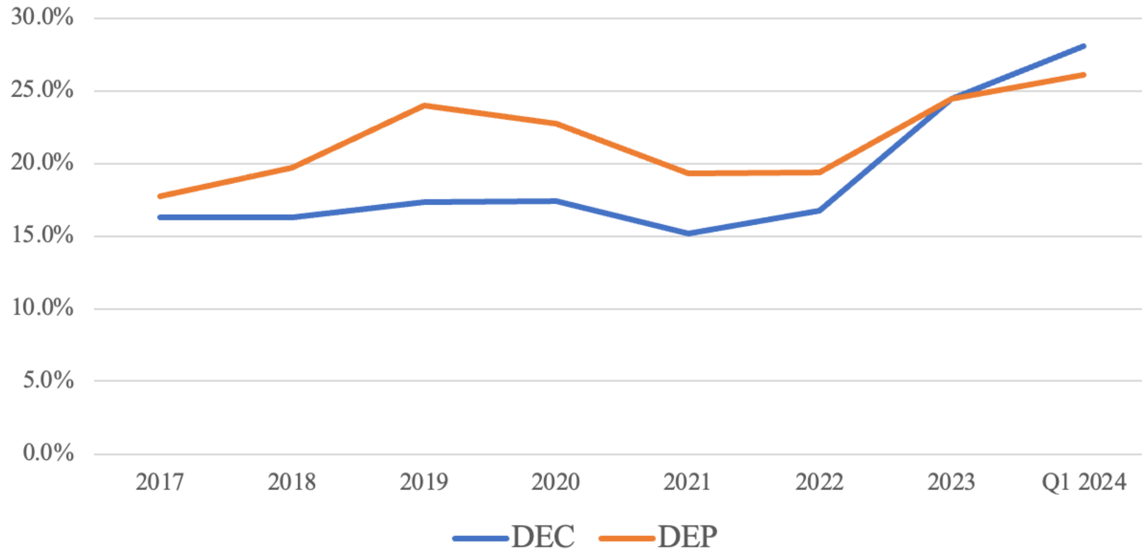
Figure 2: Duke Natural Gas Generation Additions as Share of Generation Portfolio[11]



Driven by Duke's increasing use of natural gas, DEC now has higher fuel charges (*i.e.*, a higher percentage of its total residential electricity bill is the cost of fuel) compared to DEP. Figure 3 shows DEC recently surpassed DEP in this metric and that the Companies both have fuel cost as a percentage of total residential electricity bills of between 26% to 28%.[12]

[11] *Id.*
[12] *Id.* at 2.

Figure 3: Duke Fuel Cost as Percentage of Total Residential Electricity Bills[13]



Q: Does Duke propose to further increase its reliance on natural gas in the CPIRP?

A: Yes. Going forward, the Companies propose adding just under 9,000 MW[14] of additional gas generating capacity by 2035. This additional generation would - if approved - translate into a further increase in natural gas' percentage of the Companies' system generation. The proposed increase in natural gas generating capacity can also be expected to increase natural gas fuel consumption and fuel's share of total electric bills for residential, commercial, and industrial ratepayers.

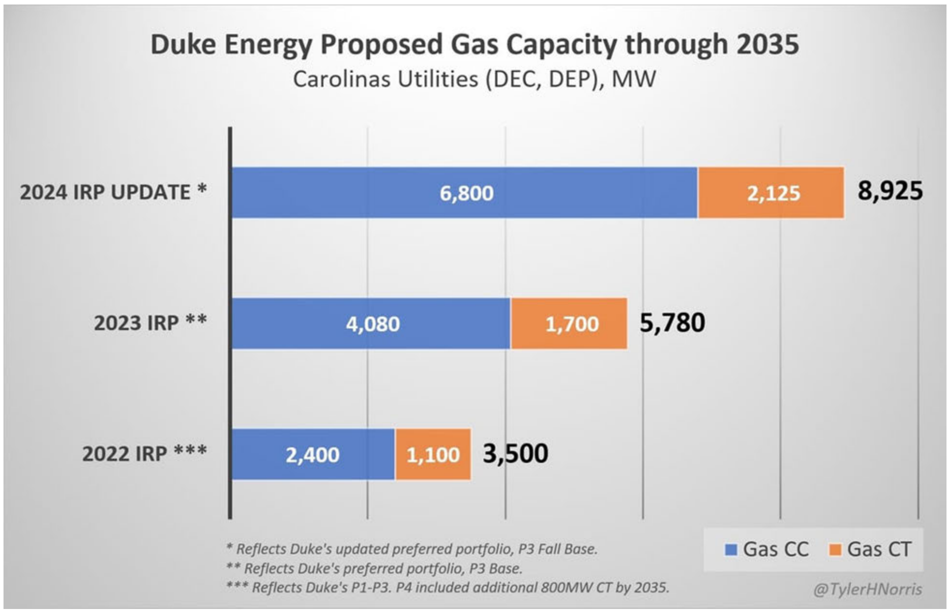
Specifically, as Duke's load projections have risen, Duke has repeatedly proposed increasing natural gas additions in the 2022 CPIRP, in the 2023 CPIRP, and in the 2024

[13] *Id.*

[14] Verified Amended Petition for Approval of 2023-2024 CPIRP, Supplemental Planning Analysis at 8 (stating that by 2035, Duke's P3 Fall Base scenario would include 6.8 GW of incremental CC capacity and 2.1 GW of incremental CT capacity).

CPIRP Supplemental update.[15] Figure 4 shows that, in this brief period, the proposed amount of incremental combustion turbine (CT) capacity has doubled and the proposed amount of incremental combined cycle (CC) capacity nearly tripled.

Figure 4: Duke Proposed Gas Capacity Through 2035 over IRP Filings[16]



Q: What is the significance to ratepayers of tripling the amount of new CC capacity compared to the smaller increase in CT capacity?

A: CTs provide generation during times of peak demand, which means relatively fewer hours of operation and minimal fuel burn. For example, during the previous period of natural gas

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[15] *See* Docket E-100, Sub 179, DEC DEP Verified Petition for Approval of Carbon Plan, Appendix M; Duke Verified Petition for Approval of 2023-2024 CPIRP, Appendix K; Verified Amended Petition for Approval of 2023-2024 CPIRP, Supplemental Planning Analysis at 8.

[16] Jeff St. John, *More demands, more gas: Inside the Southeast's dirty power push*, Canary Media (Apr. 11, 2024), https://www.canarymedia.com/articles/utilities/more-demand-more-gas-inside-the-southeasts-dirty-power-push.

price volatility in the early 2000s, Progress Energy reported in its 2004 IRP: "Gas and oil generation accounts for about 25% of total supply capacity, yet only 2% of total energy."[17]

That de minimis energy generation from the gas-fired peak capacity resulted from prudent use of CTs during times of peak demand. In the absence of "mature" alternative technologies at that time,[18] CTs provided reliable back up with minimal overall ratepayer exposure to volatile and high gas prices because they were not run to serve base load or intermediate load and provided less total energy over the course of a year. Since the Clean Air Act Amendments of 1992 initiated an initially minor shift away from coal toward more natural gas, it has generally been prudent to use natural gas CTs to serve peak loads. CTs can play a similar role today in backing up carbon-free resources to meet the carbon emission reduction goals of the CPIRP.

Adding new CCs has the opposite effect of adding CTs, increasing ratepayer exposure to gas prices over many more hours of generation. CCs are designed to run as many hours a year as possible, exposing ratepayers to increased fuel costs as CCs supply increasing percentages of overall generation. Compared to the 2% of total generation from gas during the price spikes in the early 2000s, Duke now supplies approximately 35% of generation from gas, and proposes to add another 6,800 MW of new CC capacity, up from 2,400 MW proposed just months earlier. The last decade of stable natural gas fuel prices

[17] Docket E-100, Sub 102, Progress Energy 2004 Annual Resource Plan at 24-25. Accessed at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=20ed4681-a248-4ffc-b4a8-61372f3ce33f); *see also* Verified Petition for Approval of 2023-2024 CPIRP, Chapter 1: Planning for a Changing Energy Landscape at 3 (Figure 1-1).
[18] Docket E-100, Sub 93, Carolina Power & Light 2002 Integrated Resource Plan at 3 ("Of the thirteen technologies evaluated, only eight (8) are commercially available at this time and only three (3) of those are mature, proven technologies."). Accessed at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=4e922cf2-51b3-4ab0-a8af-621f2431e045.

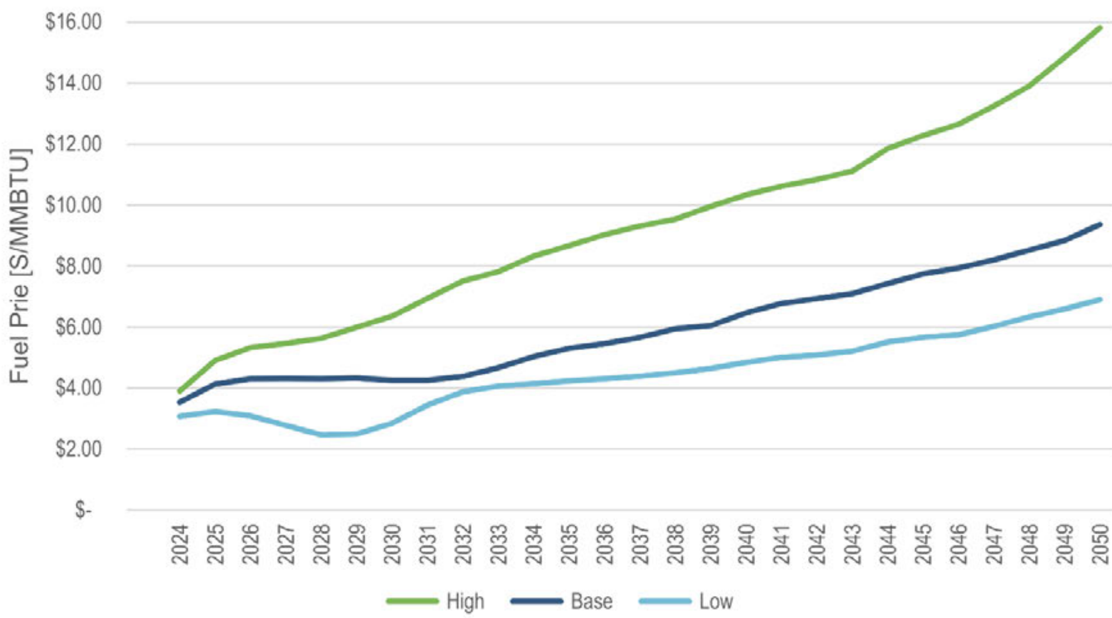
has given way to the return of volatile natural gas prices, but with greatly multiplied rate impacts because the proposed exposure of 39% of generation to volatile fuel prices in 2033 is 19 times the 2% exposure to high price volatility during the previous fuel price run-ups occurring in 2004/2005.

On top of greatly increased fuel costs, the proposed investment in CCs ties the Companies to carbon emissions well beyond the 2050 net-zero deadline. Duke's interest will be to recover its rate-of-return on this capital investment over the full useful life of these newly acquired assets through the 2060s. For Duke to earn its return, the CCs will need to be "used and useful," meaning they need to operate. With billions of dollars of investment, Duke will not let CCs sit idle. As carbon reduction mandates force replacement of natural gas generation before the end of its useful life, ratepayers will not only have paid escalated fuel costs, but will bear stranded costs as the Companies scramble to meet carbon reduction targets.

Q: What is the amount of fuel costs projected by Duke under the Companies' proposed P3 Fall Base portfolio?

A: Total fuel cost projections turn on the price and volume of natural gas consumed over time. Figure 5 presents Duke's High, Base, and Low projected prices for natural gas over the planning period.

Figure 5: High, Base, and Low Henry Hub Natural Gas Price Forecasts[19]



These are natural gas price projections based on Duke's analysis of "Market Fundamentals" of supply and demand.

Figure 6 shows the Companies' proposed natural gas fuel consumption from 2025-2049 for its preferred P3 Fall Base portfolio.[20]

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[19] Verified Petition for Approval of 2023-2024 CPIRP, Appendix C at 44 (Figure C-4).

[20] Duke Energy. EnCompass PC Run file "P3 F23 Load - Base Load - 35Cap - 1 SC CC - P3 Retire - PC - 1.9.24". Accessed via Duke Energy CPIRP Datasite. The year 2050 is not included because consumption data is only provided for a handful of months in that year.

Figure 6: Annual Natural Gas Fuel Consumption (Million MMBtu) for P3 Fall Base

[redacted]

Utilizing the Base and High natural gas fuel costs provided by the Companies, Figure 7 shows the amount of annual fuel costs under the Companies' proposed P3 Fall Base preferred portfolio. Figure 7 shows the range of annual natural gas fuel cost for the period 2025 to 2049 calculated using the Companies' gas consumption shown in Figure 6 multiplied by the Companies' nominal Base and High fuel prices. The Base natural gas price forecast would result in a cumulative natural gas fuel cost passed through to ratepayers of $[redacted] and the High natural gas price forecast would result in a cumulative natural gas fuel cost pass through of $[redacted]. The difference between the High and Base fuel price forecasts is $[redacted], or a PVRR of $[redacted].

Figure 7: Natural Gas Annual Fuel Cost Spend ($B/year)

[redacted]

Figure 7 shows that if Duke builds its proposed P3 Fall Base portfolio, consumes the proposed amount of gas, and natural gas fuel prices turn out to match the High price forecast, then the gas fuel costs that Duke will pass through to ratepayers is 65.2% higher than it assumes will occur under the Base price forecast. The magnitude of this cost risk is remarkable.

The magnitude of cost risk is equally pronounced in the nearer term, 2024 to 2035, where the difference in the cumulative natural gas fuel cost of the Base price ($[redacted]) and the High price ($[redacted]), equal to a PVRR of $[redacted], exposes ratepayers to the risk of a 67.4% higher gas fuel bill than Duke assumes will occur by relying on the Base price.

Figure 8 shows the additional annual increment in proposed natural gas fuel costs that would be recovered from ratepayers if the High gas price occurs under the implementation of Duke's proposed P3 Fall Base portfolio.

Figure 8: High Gas Price Additional Annual Fuel Cost Pass Through, P3 Fall Base ($B/year)

[redacted]

Even though the Companies state that the proposed P3 Fall Base portfolio will achieve a 70% emissions reduction by 2035, the Supplemental filing only provides calculated PVRR for years 2038 and 2050, not 2035. The Companies' supplemental filing calculates the PVRR cost of the proposed P3 Fall Base portfolio for 2038 to be $78 billion.[21] In contrast, the Supplemental states the "P2 Fall Supplemental results in a PVRR

[21] Verified Amended Petition for Approval of 2023-2024 CPIRP, Supplemental Technical Appendix at 8 (Table SPA T-7, PVRR Through 2038 for P3 Fall Base).

increase of $6 billion relative to P3 Fall Base."[22] The difference in the cumulative natural gas fuel cost of the Base price and High price for the slightly shorter yet comparable period of 2025 to 2038 is a PVRR of $[redacted] Duke's calculated cost difference of P3 Fall Base and P2 Fall Supplemental portfolios.

In light of the huge magnitude of gas fuel cost risk to ratepayers enumerated above, the much smaller PVRR difference of $6 billion between the P3 Fall Base and P2 Fall Supplemental portfolios warrants a comparative examination of gas consumption and anticipated Base and High gas fuel costs. Said another way, the magnitude of the risk Duke's customers face simply from the possibility that gas prices will be closer to the High forecast than the Base forecast far exceeds the PVRR cost differential between the P2 Fall Supplemental portfolio and the P3 Fall Base portfolio.

Figure 9 compares the proposed natural gas consumption for P3 Fall Base and P2 Fall Supplemental portfolios.[23]

[22] *Id.* at 9.
[23] Duke Energy. EnCompass PC Run file "P2 F23 Load - Base Load - 33Cap - 1 SC CC - 6 CC Avail - PC - 1.19.24". Accessed via Duke Energy CPIRP Datasite. The year 2050 is not included because consumption data is only provided for a handful of months in that year.

Figure 9: Annual Natural Gas Fuel Consumption, Comparison P2 Fall and P3 Fall

[redacted]

Figure 10 shows that the Companies' North Carolina ratepayers will face fewer natural gas fuel costs under a P2 Fall Supplemental portfolio compared to a P3 Fall Base portfolio. And this lower cost occurs under both the Companies' Base and High natural gas fuel price forecasts. The fuel cost avoidance offered by P2 Fall Supplemental is most pronounced in years [redacted].

Figure 10: Base and High Gas Fuel Cost Comparison of P2 Fall and P3 Fall

[redacted]

Using the Companies' Base gas fuel price forecast, P2 Fall Supplemental would result in $[redacted] less in natural gas fuel costs than the proposed P3 Fall Base portfolio. About [redacted]% of this avoided expense would occur in the years [redacted].

Using the Companies' High gas fuel price forecast, P2 Fall Supplemental would result in $[redacted] less natural gas fuel costs than the proposed P3 Fall Base portfolio. About [redacted]% of P2 Fall Supplemental's fuel cost reduction would occur in the years [redacted].

This initial analysis enumerates the massive fuel cost risk that the High natural gas fuel price forecast would pass through to North Carolina customers. Even before accounting for the volatility risks we discuss next, the Commission should expect natural gas prices to increase significantly in the coming decades. That increase alone requires review to determine whether P2 Fall Supplemental is actually a lower cost portfolio than the Companies' preferred P3 Fall Base portfolio even before considering the additional price volatility risks. This same logic applies to other potential portfolios that rely on less natural gas generation than the P3 Fall Base portfolio. The less a portfolio relies on natural gas generation, the lower the fuel cost exposure of customers under high-price forecasts projected by Duke.

IV. The Inherent Cost Risks of Natural Gas.

Q: Are there fuel-cost risks on top of market-fundamentals-based forward projections?

A: Yes, the additional risk comes from price volatility in natural gas markets. Volatility is when a market experiences periods of unpredictable, and sometimes sharp, price movements.[24]

Q: Are natural gas volatility costs significant to ratepayers?

A: Yes. Natural gas price forecasts are notorious for disregarding and being surprised by volatility and price spikes occurring for one reason or another. The cost to ratepayers from these events is significant, real, and can be measured by reference to past volatility events.

Q: How should the Commission estimate the magnitude of the cost to ratepayers from natural gas market volatility?

A: The starting point for measuring the cost impact of volatility is historical volatility. Figure 11 below shows natural gas prices from 2000 to 2022 adjusted for inflation to real dollars.

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[24] *Market volatility: defined and explained*, Fidelity, https://www.fidelity.com.sg/beginners/what-is-volatility/market-volatility#:~:text=Volatility%20is%20an%20investment%20term,to%20sudden%20price%20rises%20too (last visited May 23, 2024).

Figure 11: Historic Natural Gas Prices (Inflation Adjusted)[25]

Historically, and again beginning in 2022, the chart shows that volatility can quickly triple prevailing market gas prices. The 2022 runup tripled prices and was actually moderate in size compared to runups in the prior ten-year period of high volatility.

Q: How do volatility costs relate to forward price projections?

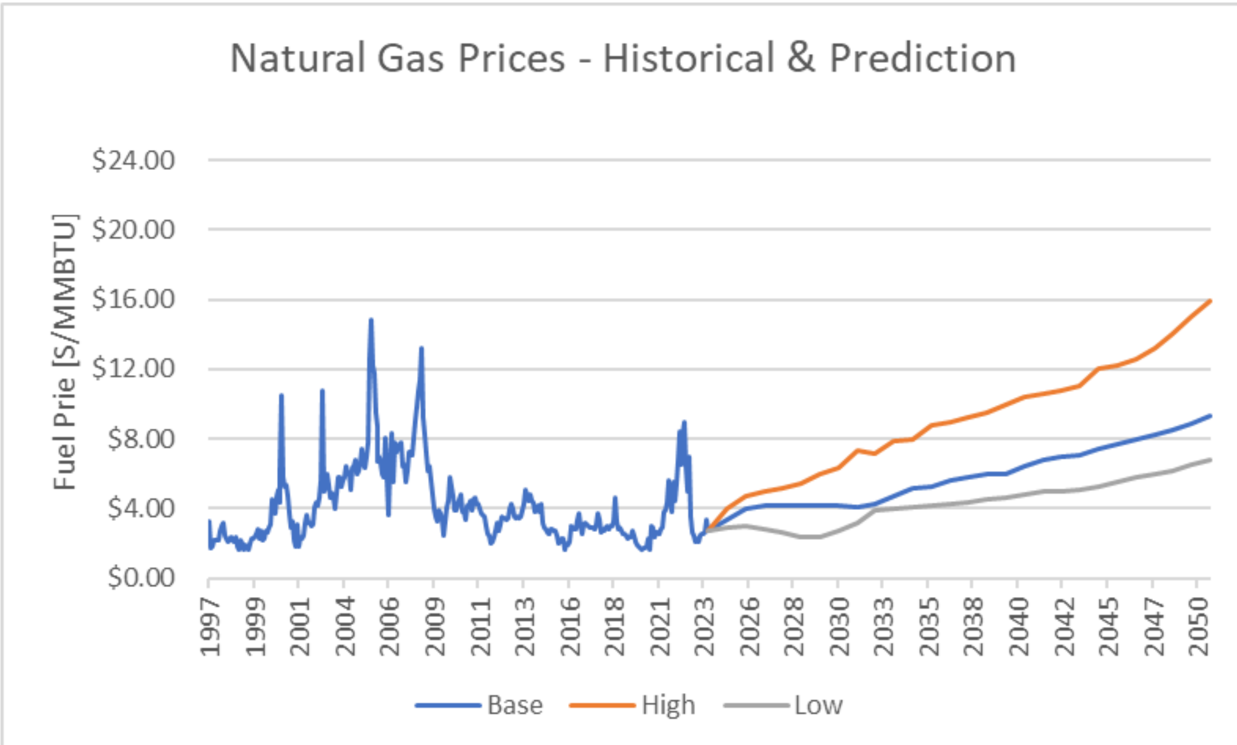
A: Forward price projections reflect the predicted long-term trends in market prices over time based on market fundamentals of supply and demand, which can be tracked and projected into the future. Duke's high, medium, and low forward price curves reflect that range of uncertainty in market fundamentals. For the last ten years we have been in a period of relatively low, flat prices for natural gas based on increased supply from fracking in the U.S.

[25] *Natural Gas Prices – Historical Chart*, MacroTrends, https://www.macrotrends.net/2478/natural-gas-prices-historical-chart (last visited May 23, 2024).

Volatility results from short-term unexpected events that are not included in supply-and-demand forecasts and that drive prices above forecasts for limited periods. Volatility price shocks ride on top of the base price at the time. The historical price chart above shows that the 2022 runup in prices came on top of the 10-year period of relatively low and uniform natural gas prices.

For comparison on size and impact, the chart below shows the magnitude of the past volatility spikes in gas prices on the same chart as the rising forward price projections presented in the Plan in nominal dollars. Volatility swings in the future would ride on top of the uniformly increasing forward price curves, increasing the cost to ratepayers.

Figure 12: Duke Forward Natural Gas Prices Plotted Against Historical[26]
(Nominal $/MMBtu)



And the cost to ratepayers from any price rise is multiplied by the increased consumption proposed by Duke.

Q: Can the Commission ignore volatility spikes because they are short term?

A: If the spikes and runups were small blips on the base price curve the Commission might be able to ignore them as utilities generally did during the ten-year period of flat prices prior to 2022. The ratepayer cost and pain from the 2022 price runup,[27] which was relatively moderate in the history of natural gas markets and was passed through to ratepayers in

[26] We derived the historical data through *Natural Gas Prices – Historical Chart*, MacroTrends, https://www.macrotrends.net/2478/natural-gas-prices-historical-chart (last visited May 23, 2024). The predictive prices can be found at Verified Petition for Approval of 2023-2024 CPIRP, Appendix C at 44 (Figure C-4).
[27] Global natural gas prices spiked in 2022 as a result of disruption of natural gas supply to Europe following the Russian invasion of Ukraine caused natural gas prices in the U.S. to triple and remain above forecasts until global supplies loosened as a result of a warm winter in Europe.

2023, provides a recently calibrated ruler by which the Commission can measure volatility costs going forward.

Q: What costs did ratepayers see as a result of the 2022 price spike?

A: DEC and DEP's purchases of natural gas had been increasing in the period leading up to the 2022 fuel price shock. From January 1, 2020 through December 31, 2022, the Companies' year-over-year volume of natural gas purchases [redacted]% in 2021 and [redacted]% in 2022. Natural gas prices [redacted]% in 2021 ([redacted]) followed by [redacted]% in 2022 ([redacted]). The year-over-year increase in Duke's total gas fuel spend from 2021 to 2022 was $[redacted], of which $[redacted] was the result of the spike in U.S. natural gas prices driven primarily by events in Europe.[28] This [redacted] in 2021, approximately $[redacted] of which was attributable to the run-up in natural gas fuel prices that year. Over this two-year period, the volatility in natural gas prices in distant markets resulted in an additional approximately $[redacted] in natural gas fuel costs passed through to Duke ratepayers.

A recent analysis by EQ Research calculates that the fuel-clause adjustment necessary for Duke to pass through all of the cost of the 2022 natural gas fuel price shock to ratepayers equates to a roughly 1.27 cents/kWh increase in the average Duke Energy Carolinas residential customer's rates, or a 32.5% increase over the existing total fuel rate of 3.90 cents/kWh from this single event.[29]

[28] CONFIDENTIAL_DEC and DEP Response to CEBA DR2-13 (E-100 Sub 190).docx and embedded Excel file named "CONFIDENTIAL CEBA 2-13 DEC_DEP Natural Gas Deliveries_012020_122022".
[29] EQ Research LLC, *supra* note 10.

Q: With natural gas prices back down this year, can the 2022 price shock be considered a one-off event?

A: No, just the opposite. Irreversible trends globally and locally, outside the control of Duke or the Commission, each separately bring volatility costs at levels higher than the 2022 price shock and higher than seen in the past.

First, global market prices are driving, and will increasingly continue to drive, domestic gas prices as increasing U.S. exports tie U.S. natural gas more directly to both global prices and volatility.

Second, regional constraints on natural gas supply, storage, and transport in the Carolinas add a separate source of risk, price volatility, and price shocks that can only be avoided by increasing reliance on in-state non-gas resources.

These extraordinary fuel costs are frequently overlooked as a driver in rates, just as they were in the years preceding the 2022 runup of $[redacted] in ratepayer costs, and as they are in Duke's current CPIRP proposal, because North Carolina utilities pass those fuel costs directly to customers. There is no downside risk or upside incentive for the utilities to mitigate or consider these costs to customers. These fuel costs are overlooked until they cause "unexpected" painful rate increases. The surprise 2022 fuel-cost passthrough is small in comparison to the exposure that would result from the increased reliance on natural gas that Duke is proposing at a time when global and regional volatility is rising.

The historical volatility shows that the impact of price spikes on natural gas prices is multiples of two- or three-times business-as-usual projected prices. Volatility adds risk on top of the forward price projections, which show natural gas prices increasing under all scenarios. As the next two sections show, global and regional conditions increase the likelihood and magnitude of volatility events during the coming decades.

V. Global Pricing and Volatility.

Q: Why will global prices for natural gas affect Carolina ratepayers?

A: We have just entered a new era of global markets for natural gas. In the past, domestically produced natural gas had very little access to global markets and global prices had minimal effect on U.S. prices. Unlike oil, where prices have been set by global supply and demand for fifty years and we have lived with the resulting swings in the price of gasoline at the pump, the price of domestic natural gas in recent history has been largely unaffected by global markets. Lack of export capacity to global markets in the past has insulated U.S. natural gas from global price volatility. That isolation has come to an end as capacity to export U.S. natural gas to higher price global markets expands rapidly.

With the expansion of LNG export capacity and rapid growth of receiving terminals around the world, natural gas produced in the United States is now serving a global market. Already, the United States is the largest exporter of LNG and exports continue to expand. The sharp rise resulting from disruption of natural gas supplies triggered by the start of the Russian invasion of Ukraine is the first rate-shock in global natural gas markets felt by utility ratepayers in the U.S. As U.S. LNG and pipeline export capacity grows, the impact of global price swings on ratepayers grows with it. Global prices are both much higher and more volatile than domestic natural gas prices, which were relatively low and relatively stable in the decade before the 2022 runup. The Ukraine gas price shock marked the end of the period of low and stable prices attributable to domestic access to domestic supply not competing in global markets.

Q: What are the factors that increase ratepayers' exposure to global natural gas prices?

A: U.S. LNG export capacity is expanding. The U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) for 2023 projects that LNG exports will increase 150% by the mid-2030s.[30] According to FERC's most recent LNG facility report, U.S. LNG export capacity is currently 14.4 billion cubic feet per day (Bcf/D) and expected to rise to 55.0 Bcf/D.[31] Seventeen of the eighteen approved but not yet constructed facilities are expected to be constructed by 2030,[32] pending the outcome of the Biden Administration's temporary hold on LNG development. Specifically, FERC reports there are eight existing U.S. LNG export facilities (total capacity of 14.43 Bcf/D), seven facilities approved and under construction (16.93 Bcf/D), and eleven facilities approved but not yet under construction (15.04 Bcf/D).[33] Additionally, the FERC report indicates an additional four proposed facilities and two facilities in the pre-filing phase (8.58 Bcf/D).[34] These projects will enable the United States to triple its LNG export capacity, but are not inclusive of possible expansion of natural gas pipeline export capacity to Mexico.

[30] U.S. Energy Information Administration, Annual Energy Outlook: AEO2023 at 28 (March 2023). Accessed at https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Narrative.pdf.
[31] Federal Energy Regulatory Commission, U.S. LNG Export Terminals – Existing, Approved not Yet Built, and Proposed (Feb. 20, 2024). Accessed at: https://www.ferc.gov/media/us-lng-export-terminals-existing-approved-not-yet-built-and-proposed.
[32] *Id.*
[33] *Id.*
[34] *Id.*

Q: Are U.S. natural gas exports significant in relation to total us demand?

A: With the rapid expansion of ports, natural gas exports, both via pipeline and LNG, are projected to be the largest sector of U.S. natural gas demand by 2030. U.S. natural gas production reached an all-time high in 2023 and allowed the U.S. to satisfy domestic demand, export natural gas to Mexico via pipeline, and export LNG, primarily to Europe and Asia.[35] However, exports are continuing to grow. By 2028, LNG exports are likely to increase from 13% of domestic dry gas production up to 20%.[36] Moreover, the EIA projects in its 2023 AEO that by 2030, "natural gas exports, by pipeline or as LNG, will become larger than any domestic end-use sector, including residential, commercial, industrial, and electric generation . . . to become the largest component of U.S. natural gas demand."[37]

Q: Can the U.S. meet global demand for U.S. natural gas by increasing production?

A: Global demand is rising faster than domestic gas production. The EIA recently found that LNG exports will increase 152% between 2022 to 2050 while natural gas production increases 15%, or 1/10 that amount.[38] Figure 13 illustrates that demand for U.S. LNG exports has been rising over the last seven years, primarily from Europe and Asia.[39]

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[35] Laia Munoz-Cortijo and Troy Cook, *U.S. monthly dry natural gas production set a new record in December 2023*, U.S. Energy Industry Association (Jan. 24, 2024), https://www.eia.gov/todayinenergy/detail.php?id=61263#:~:text=Despite%20recent%20increases%20in%20Lower,in%202023%20than%20in%202022.

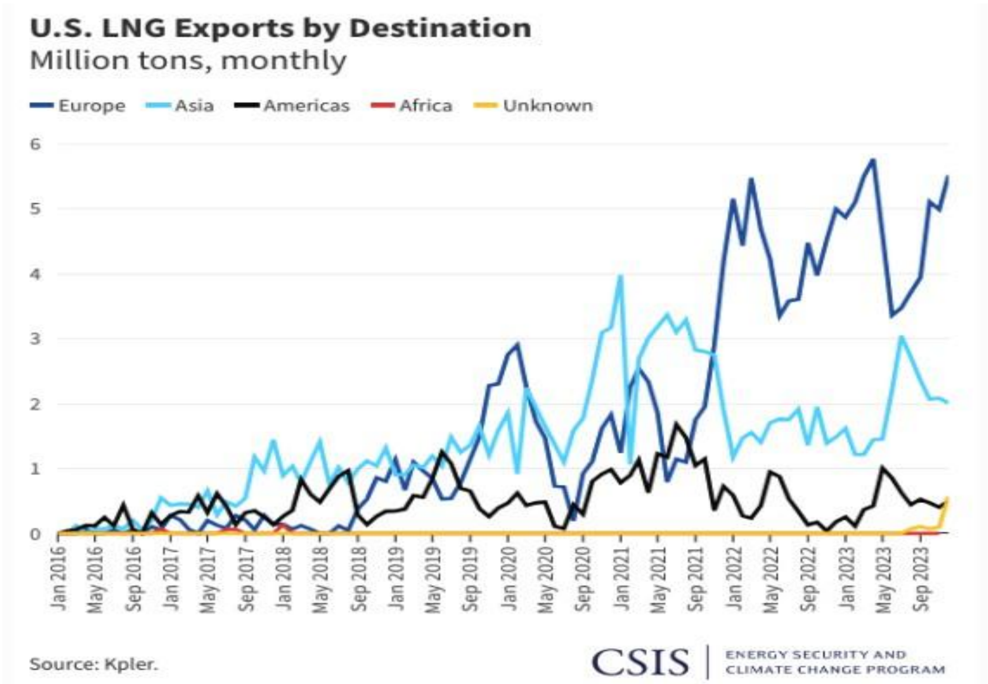
[36] Ben Cahill, *U.S. LNG Export Boom: Defining National Interests*, Center for Strategic and International Studies (Jan. 11, 2024), https://www.csis.org/analysis/us-lng-export-boom-defining-national-interests.

[37] U.S. Energy Information Administration, AEO 2023 Issues in Focus: Effects of Liquefied Natural Gas Exports on the U.S. Natural Gas Market at 3 (May 2023). Accessed at: https://www.energy.gov/sites/default/files/2023-08/Exhibit%20A%20EIA%20LNG_Issue_in_Focus%20%281%29.pdf.

[38] *U.S. natural gas production and LNG exports will likely grow through 2050 in AEO2023*, U.S. Energy Information Administration (Apr. 27, 2023), https://www.eia.gov/todayinenergy/detail.php?id=56320#:~:text=In%20our%20Annual%20Energy%20Outlook,feet%20(Tcf)%20by%202050.

[39] Cahill, *supra* note 36.

Figure 13: U.S. LNG Exports by Destination[40]



The same EIA report found that this increase in LNG exports will likely lead to domestic price increases. The report states that the key determinants of LNG export volumes are international LNG prices and the rate at which new LNG export terminals can be constructed. "Model results showed that **higher LNG exports results in upward pressure on U.S. natural gas prices** and that lower U.S. LNG exports results in downward pressure."[41] The report confirms that in EIA's reference case, in the future, producers of natural gas are likely to export more gas, and domestic prices will likely be higher.[42]

[40] *Id.*
[41] U.S. Energy Information Administration, *supra* note 37 at 4.
[42] *Id* at 3-4.

Q: What does exposure to global markets mean for natural gas prices in the U.S.?

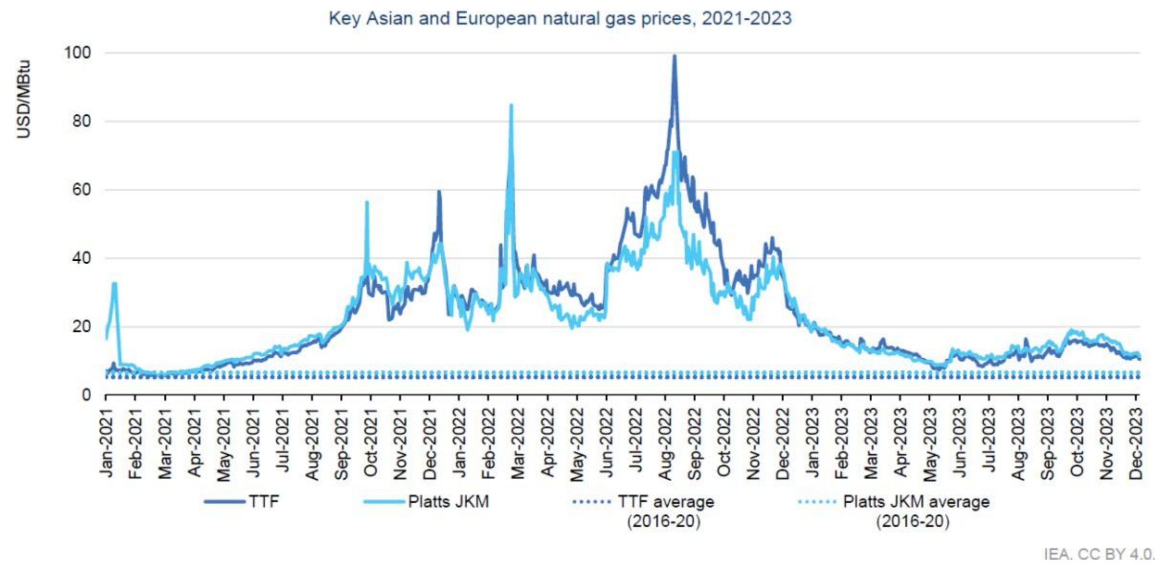
A: As noted above, natural gas prices are likely to increase alongside rising LNG exports. This price increase is, in part, due to competition as natural gas importing countries consistently pay well above historical natural gas prices in the U.S. As shown in Figure 14, recent monthly TTF (Europe) and Platts JKM (northern Asia) data[43] for Europe and Asia respectively show the market price for gas between \$5/MMBtu and just under \$100/MMBtu, which was above both of their historical averages and the domestic Henry Hub Price.[44] At the end of 2023, as the market fundamentals eased, European and Asian markets were still paying about \$15/MMBtu for natural gas.[45]

[43] Platts JKM (https://www.spglobal.com/commodityinsights/en/our-methodology/price-assessments/lng/jkm-japan-korea-marker-gas-price-assessments) is the Northeast Asian LNG benchmark price assessment for spot physical cargoes delivered to Japan, South Korea, China and Taiwan. The Title Transfer Facility, or TTF, is the main reference virtual market for gas trading in Europe, based in Amsterdam, the Netherlands. The Dutch TTF (https://tradingeconomics.com/commodity/eu-natural-gas) has become the most liquid pricing location and is the benchmark for natural gas in the European market.

[44] International Energy Agency, Gas Market Report, Q1-2024. Accessed at: https://iea.blob.core.windows.net/assets/601bff14-5d9b-4fef-8ecc-d7b2e8e7449a/GasMarketReportQ12024.pdf.

[45] *Id* at 9.

Figure 14: Natural Gas Prices in Key Asian and European Markets[46]

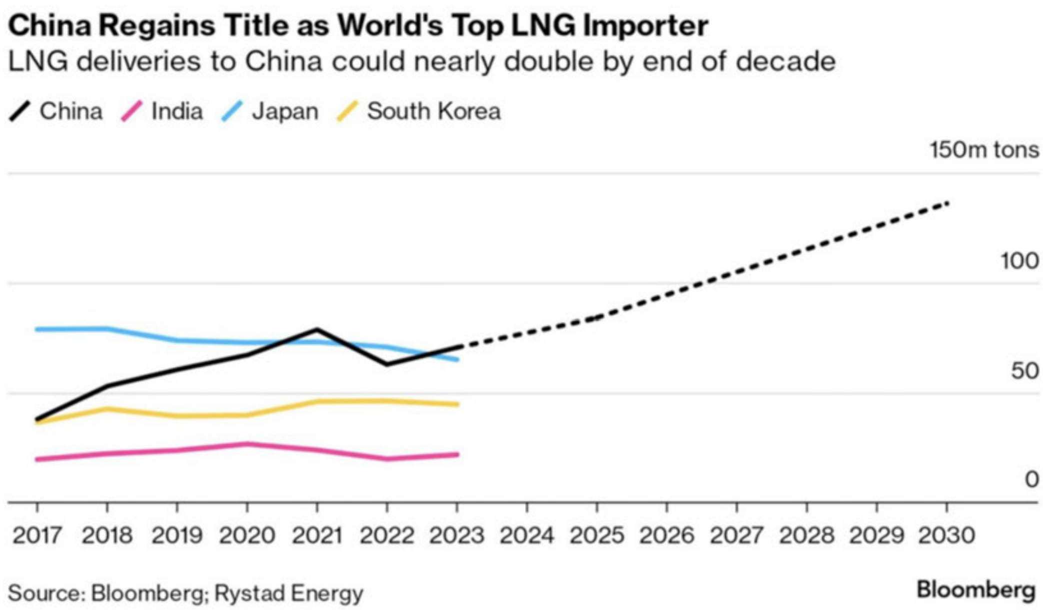


Q: Is the global market likely to stabilize in the years ahead?

A: There is no reason to assume that global pricing of natural gas will be stable or predictable in the next decade. The forces driving global demand, as well as geopolitical risk, are intensifying in many regions of the world. For example, with respect to one of many demand forces at play globally, China's LNG imports are projected to double from 71 million tons in 2023 to 140 million tons in 2030, as projected in Figure 15.[47]

[46] *Id.*
[47] Stephen Stapczynksi, *China Regains LNG Buyer's Crown as Rivals Brace for More Growth*, Bloomberg (Jan. 2, 2024), https://www.bloomberg.com/news/articles/2024-01-04/china-regains-lng-buyer-s-crown-as-rivals-brace-for-more-growth.

Figure 15: LNG Deliveries to Top LNG Importing Countries[48]



China's growing appetite for natural gas alone will ensure sustained higher global demand for U.S. and global natural gas, promising there will be a global market price premium on firm LNG supply that is higher than U.S. domestic gas market prices. This expanding market among more countries increases not only the base demand but also the risk of periodic or even sustained periods of geo-political disruptions in supply and transport. The world just came through the first significant, global market price spike resulting from the Russian invasion of Ukraine, but it is reasonable to expect that there will be more unforeseeable events that impact gas prices in the future. The market pull from expanding global demand at significantly higher prices is not something that can be avoided. The U.S. cannot put the "domestic-gas-market genie" back in the bottle. Unlike just a few years ago, moving forward, electric customers relying on natural gas generation

[48] *Id.*

are buying electricity at prices set increasingly by global gas markets.

VI. Regional Volatility Risks.

Q: You have described higher ratepayer costs that result from increasing the natural gas burn as projected fuel prices rise, and the additional volatility risk on top of that from increasing ties to global markets. Are there any other risks to ratepayers from relying on natural gas for electricity?

A: Yes, the regional and local constraints on natural gas supply pose a significant additional risk to Carolina ratepayers independent of increases in fundamental market prices and global volatility. Neither North nor South Carolina have natural gas resources or production within the state and rely entirely on natural gas shipped from out-of-state through interstate pipelines to supply generators in the state.

Q: Are out-of-state natural gas supplies and interstate pipelines sufficient to supply the natural gas needed for the CC and CT generation that Duke proposes in the CPIRP?

A: No. Out-of-state gas supply and interstate pipelines are not sufficient to supply either existing or proposed natural gas generation. Duke has burned diesel and coal in its units at various times throughout the year due to insufficient gas supply. Duke acknowledges that natural gas supply meets "less than half of its current combined cycle design capacity need and less than a quarter of the current gas fleet's historical peak gas burn."[49] Firming up gas supply for increased natural gas generation would require new pipelines and access to out-of-state gas storage facilities. As stated in the CPIRP:

> The Transcontinental Gas Pipe Line ("Transco"), the primary interstate gas infrastructure through the Carolinas is fully subscribed and oftentimes

[49] Verified Petition for Approval of 2023-2024 CPIRP, Appendix K at 3.

> constrained. Over the past decade in the Carolinas, natural gas demand growth has outpaced increases in gas delivery capacity.[50]

Duke acknowledges that the gas fleet cannot operate at full capacity during times of peak demand:

> These restrictions, compounded by Transco's physical flow limitations, bind the Companies' ability to operate their respective gas fleets at full capacity throughout the year. The Companies, however, currently successfully manage this through the usage of alternative fuels, namely diesel and coal. To transition away from coal, however, the Companies need to increase the fuel security of natural gas so that they will have the reliable supply the combined fleet needs during peak demand periods.[51]

Firming up gas supply for increased natural gas generation would require new pipelines and accompanying gas storage facilities. As a proposed solution, Duke provides updates on the Mountain Valley Pipeline and refers to the infrastructure that would be necessary to bring Gulf Coast gas to the Carolinas.[52] In support, Duke cites the Department of Energy's call for more pipelines.[53] Recent natural gas pipeline proposals in the Carolinas have faced significant opposition and cancellation, most notably Dominion Energy and Duke Energy's 2020 decision to cancel the Atlantic Coast Pipeline. This regional trend stands in stark contrast to the 13.5 billion cubic feet per day of new pipeline capacity under construction to supply five new LNG export terminals across Texas and the Gulf Coast.[54] Of course, a call for more pipelines is not a strategy for resource adequacy and is not a

[50] *Id.*
[51] *Id.*
[52] *Id.* at 3-4.
[53] *Id.* at 4.
[54] Katy Fleury, *New Pipelines Will Bring Significant Volumes of Natural Gas to New LNG Export Terminals*, U.S. Energy Information Administration (Dec. 12, 2023), https://www.eia.gov/todayinenergy/detail.php?id=61062.

reliable resource plan, as evidenced by the extraordinary lengths Congress took to legislatively force approval of the Mountain Valley Pipeline.[55]

Because North Carolina has no natural gas production and no known suitable formations for gas storage,[56] the CPIRP notes that Duke would need additional pipeline capacity to access out-of-state storage facilities "while also ultimately increasing on-site fuel storage."[57] Duke did not account for the considerable cost of natural gas storage facilities in the CPIRP that it says are a potential solution to this supply risk.[58] The Companies acknowledge that the lack of regional gas resources and infrastructure presents economic risk:

> To account for potential physical and economic constraints of natural gas to the Companies' service territories, the Companies limit operations of some generation units to coal and ULSD [Diesel] during times of potentially limited supply and price volatility.[59]

Discovery confirmed that the proposed diesel-back-up strategy is already used for peaking units in January:

> To represent potential physical and economic constraints of natural gas to the Companies' service territories, the Companies limited operations of all DFO [Distillate Fuel Oil] units to coal and all CTs to ultra-low sulfur diesel (ULSD) for the month of January inside of Encompass.[60]

CT peaking units operate for much fewer hours and require a small fraction of the fuel of the CC units Duke proposes to meet additional demand. CCs operate at much higher capacity factors and require much higher volumes of natural gas. The CPIRP acknowledges

[55] Verified Petition for Approval of 2023-2024 CPIRP, Appendix K at 4.
[56] *Id.* at 3.
[57] *Id.* at 2-3.
[58] Two LNG fuel storage units currently being pursued by Dominion Energy in North Carolina are initially estimated to cost $400 million.
[59] Verified Petition for Approval of 2023-2024 CPIRP, Appendix C at 45.
[60] Duke Response to SACE DR5-21 (E-100 Sub 190) (Exhibit 1).

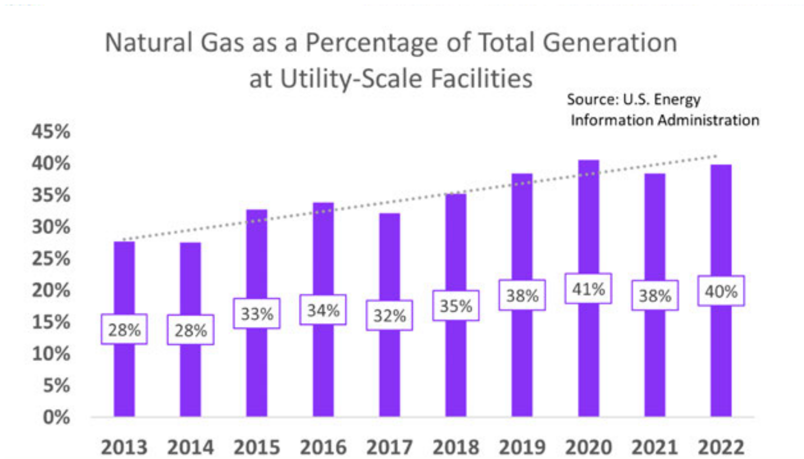
that the current and additional proposed fleet of CCs cannot be served by the regional natural gas infrastructure "[w]ithout additional interstate FT [Firm Transmission]."[61] If Duke does not receive this additional firm transmission, "the Companies would continue to have an interstate portfolio that is less than half of its current CC design capacity and less than a quarter of the current gas fleet's historical peak gas burn."[62]

Q: Other than the absence of natural gas resources and shortage of pipeline capacity, are there other developments that affect natural gas supply and demand in the region?

A: Yes. Adding to the regional supply imbalance and risk of disruption, particularly in the event of extreme weather and other demand spikes, is the fact that other utilities in the region are planning to expand natural gas use for electric generation. Figure 16 shows the increasing utility reliance on natural gas generation nationally.

[61] Verified Petition for Approval of 2023-2024 CPIRP, Appendix K at 3.
[62] *Id*.

Figure 16: Natural Gas as Percentage of Generation Nationally[63]



This trend is accelerating in the southeast region. Namely, of the more than 50,000 MW of new gas plants planned nationwide, utilities in Alabama, Georgia, North Carolina, South Carolina, Tennessee, and Virginia, which rely on some of the same regional gas resources and transmission network as the Companies, are planning to add about 33,000 MW of new gas plants by the early 2030s.[64]

The shortage of regional gas deliverability in the Carolinas along with increasing demand from utilities in surrounding states creates two serious ratepayer concerns. First, it threatens Duke's ability to meet basic reliability standards. Second, it presents a much higher probability, and even likelihood, of fuel-rate increases passed on to ratepayers from sporadic shortfalls in gas deliverability.

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[63] *Natural Gas Use for Electric Power Generation is Reaching New Records in 2023*, American Gas Association, https://www.aga.org/research-policy/resource-library/natural-gas-use-for-electric-power-generation-is-reaching-new-records-in-2023/ (last visited May 23, 2024).
[64] St. John, *supra* note 16.

Q: Are you saying the Commission should consider it likely that regional supply disruptions in natural gas supply will occur in the future?

A: Yes. Weather extremes, curtailed supply, and operating deficiencies under surprise conditions have caused sharp price increases passed through to ratepayers even in parts of the country with much stronger natural gas infrastructure and in times of relatively calm and low natural gas prices nationally, as described below.

Q: Is there a way to estimate the magnitude of ratepayer impacts that result from these regional gas constraints?

A: The Commission can estimate the level of rate impact from sporadic shortfalls of gas supply by looking at the impact of regional shortfalls that have occurred in other regions. For example, in February 2021, gas commodity prices were stable and low across the country when Winter Storm Uri went through the Gulf region. Despite robust natural gas infrastructure and supply in the Gulf region and the West generally, gas deliverability and transport were severely curtailed. Gas prices spiked as utilities competed with other users for gas supply. Although the supply crisis lasted only a few days and national commodity gas prices were not significantly impacted, the regional disruption resulted in huge fuel-adjustment rate increases to ratepayers that took years to sort out. As described by one Texas lawmaker last year:

> [T]he pain from Uri will linger for years to come on our monthly electric bills — to the tune of at least $10 billion in surcharges on top of higher electricity rates . . . . [T]he customers paid a great price. They're gonna pay it for decades.[65]

[65] Editorial Board, *Editorial: Texans pay for Uri grid failures every month. Are we about to get bilked again?*, Houston Chronicle (Feb. 14, 2023), https://www.houstonchronicle.com/opinion/editorials/article/editorial-uri-raised-electric-bills-texas-grid-17781368.php.

In an attempt to lower the pain for its gas customers, one utility obtained approval to securitize the extra fuel costs for repayment through a residential customer monthly bill charge extending out 16 years and averaging $4.29 per month through the year 2038, all necessary "because of a few days of high-cost gas."[66]

Rather than ameliorating the contagion of fuel price risk, pipelines connecting Carolinas to neighboring states, as proposed in the CPIRP, bring regional price volatility to all the states in the region. In Winter Storm Uri, Colorado, a thousand miles to the north of the storm's path and with gas production and transport, paid the price for the infrastructure failures in the Gulf, as summarized in the following news coverage:

> The Colorado Utilities Public Commission on Wednesday gave Xcel Energy the go-ahead to collect a half billion dollars from its customers to cover the spiraling costs of natural gas during a winter cold snap in 2021 — but the commissioners weren't happy about it.[67]

Q: How are those rate shocks in other regions relevant to ratepayers in the Carolinas?

A: As Duke conceded, natural gas infrastructure is far more constrained in the Carolinas than in the West or in the Gulf region. There are no natural gas resources or suitable geologic formations for gas storage in either North or South Carolina. In fact, Duke hypothesizes new pipelines from the Gulf region to the Carolinas as a solution to the weak natural gas infrastructure.[68] Therefore, decades-long rate impacts from a single extreme weather event

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[66] R.A. Dyer, *Texas Gas Utility Customers Face 16 Years of Charges from Winter Storm Uri Consumption*, Atmos Cities Steering Committee (Nov, 6, 2023), https://atmoscitiessteeringcommittee.org/texas-gas-utility-customers-face-16-years-of-charges-from-winter-storm-uri/.

[67] Mark Jaffe, *Xcel Energy cleared to collect $500 million from Coloradans for storm, but regulators say it can't happen again*, Colorado Sun (June 22, 2022), https://coloradosun.com/2022/06/22/xcel-energy-winter-storm-gas-prices/. Xcel Energy since submitted an 80% carbon-reduction plan for its utilities in Minnesota and Colorado relying on renewables backed by simple cycle natural gas generation operating a relatively few hours per year.

[68] Verified Petition for Approval of 2023-2024 CPIRP, Appendix K at 3-4.

are just as likely in North Carolina. Duke's proposal to increase its reliance on natural gas increases the likelihood that a single regional weather event will have long-lasting and severe rate impacts. Ratepayers and Commissioners here face the same or greater risk of unhappiness from unexpected fuel payments as experienced by the ratepayers and commissioners in Texas and Colorado.

VII. Implications of Natural Gas Cost Risks for Resource Planning.

Q: How should the risks from increasing natural gas volatility coming from three different directions – domestic, global, and regional – be factored into the Commission's choice of a resource portfolio and near-term action plan?

A: The increased volatility of fuel prices can be expected to increase the actual costs borne by ratepayers above the forward fuel price projections included in the CPIRP. What that means, apart from the risk from delaying carbon reductions, is that the costs projected for the portfolios with large increases in natural gas fueled generation are too low, namely P2 Fall Supplemental and P3 Fall Base. Duke's Director of IRP Advanced Analytics, Mike Quinto, acknowledged during one of Duke's CPIRP stakeholder meetings that if the price of natural gas comes in higher than the fundamental supply-demand price forecasts, Duke's modeling would select a different set of resources:

> Natural gas commodity price forecast is a key input to our modeling process. As many of you know, the price of natural gas can influence the selection of resources. It may change a CT to a Combined Cycle. **It may, if prices are higher, it may incentivize other resources.** All else equal it can change the operations of the systems. So if you have the same set of resources on the system, depending on what the gas price is, can determine if those gas units run more or less. Then certainly the overall cost of the portfolio. If the resources on the system all operate the same and gas prices

> are higher, the cost of the system is going to be higher. Definitely a key input.[69]

Q: Does Duke take into account the added cost of volatility in natural gas prices?

It does for a short period. Duke acknowledges that hedging fuel costs is necessary to protect ratepayers from volatility risks, but limits that protection to five years:

> Additionally, the use of five years' worth of market we thought is an appropriate number. Five years is generally where our hedging program comes with natural gas fuel pricing. So we're looking to **minimize cost impacts to customers by hedging fuel prices out at least five years**. So that's why we think that number is appropriate. We can purchase at that level out to five years out and further. But focusing on five years we think is appropriate and then transitioning to that fundamentals forecast over the next three years.[70]

Q: Does the five-year "hedging program" minimize cost impacts to customers from gas price volatility?

A: Five-year hedges eliminate risks from volatility only for five years, and only from the volumes of gas hedged. The billions of dollars passed through to customers following the 2022 volatility spike show that a large amount of the gas used for generation was not hedged. To the extent some volumes of gas are hedged, five years is not a sufficient duration to mitigate or minimize volatility costs to customers. Hedging all or most of the volume of gas over the intended life of the generation asset would be necessary to eliminate or significantly minimize volatility costs to customers.

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[69] Duke, *1- Natural Gas Price Forecast Methodology*, YouTube (Mar. 31, 2023), https://www.youtube.com/watch?v=NVP8mgPvg4Q (quote is stated from 1:23 to 2:25 of the video) (emphasis added).

[70] *Id.* (quote is stated from 7:50 to 8:30 of the video) (emphasis added).

Q: Are hedges available to cover the volatility risks to customers at the volumes necessary to supply the natural gas generation proposed in the plan?

A: Long-dated natural gas price hedges in the 10-to-12-year range are available, usually in volumes smaller than those that would be purchased by Duke. Duke is relying on gas being available at larger volumes for longer periods than most buyers in the market. Few buyers at those volumes with the credit to back a hedge at that dollar amount means there is no market liquidity for hedges at those volumes with the 20-to-30-year term that would be necessary to absorb the volatility risks present here.

But the fact that there are no liquid trading markets to hedge volatility risk at the volumes and term required by the Companies' proposed Plan does not mean the risk cannot be quantified in terms of the cost to ratepayers. Structured hedges or long-term contracts for twenty or more years at the proposed volumes can be priced and purchased from large-cap investment banks or large-cap producers. The cost of a long-term hedge will depend on the long-term forward price curves of the bank or other hedge provider, the credit of the buyer, the volume and term of the hedge, the basis risk from Henry Hub pricing to the delivery point, and the cost and availability of firm transmission capacity. Each of those factors contribute to the overall hedge price. Aside from credit, in which Duke should be top of the class, each of the other factors likely adds cost to a long-term price hedge in the Carolinas over other regions with more abundant and reliable gas supplies. Given Duke's industry standing and regulatory-backed credit, any of the large-cap banks trading natural gas would readily structure, price, and offer Duke a fuel-cost hedge for all of the natural gas necessary to supply the preferred portfolio over the long-term.

Q: How is the price of a long-term price hedge relevant to this proceeding?

A: Customers are being asked to accept and pay for each of the elements of risk that go into pricing a full-volume, long-term price hedge listed above. For example, covering price volatility in the out years puts greater value at risk, requiring greater reserves to pay for the spikes and runups as they occur, just as ratepayers paid for the 2022 runup. Sophisticated investment bankers at top investment banks could quantify those values and put their capital at risk to price the hedge. The cost of that hedge is equal to the cost of the volatility risks that are imposed on customers in the absence of the hedge.

On the other hand, with the hedge in place, natural gas costs would be fixed and volatility risks and costs would be eliminated. Accordingly, only when the cost of hedging fuel cost risks is included in the cost of gas can the cost of gas generation be compared accurately to the cost of fuel-free resources like solar and wind, which do not face fuel cost risks. The fact that Duke chooses not to hedge fuel costs after five years shows that it chooses not to include the full cost of natural gas generation in its choice of a preferred portfolio on the assumption it can pass fuel cost risks onto ratepayers outside of the economic analysis.

The Commission should require Duke to obtain at least two or preferably three quotes from reputable banks qualified in the field to fully hedge fuel costs for the natural gas generation proposed in the Plan for the useful life of those assets. Including the fully hedged fuel costs provides a more valid cost comparison of gas generation with other resource options in terms of the actual costs they will impose on ratepayers.

Q: What might explain why Duke does not adequately account for these costs and risks in the proposed CPRIP?

A: There are two sources of planning bias that favor increased use of natural gas at ratepayers' expense. The Commission should even the playing field in considering the best portfolio to minimize ratepayer risk.

1. 100% Fuel Cost Recovery Introduces Resource Bias

First, because 100% of fuel costs are passed through to ratepayers with no impact on the Companies' financials or returns, there is no financial incentive for the utility to minimize natural gas capital expenditures or hedge natural gas fuel costs. Most recently, Duke's existing methods for fuel hedging did not prevent an additional $[redacted] in pass-through fuel expenses resulting from the 2022 price spike. Under this pass-through policy, the Commission bears the singular responsibility to protect ratepayers from fuel risks.

2. Projected Costs Applied Unequally to Resource Options

Second, to arrive at its preferred P3 and subsequent P3 Fall Base portfolios, Duke takes significant regional planning risks for natural gas that it specifically says should not be taken for other less risky and lower cost resources. For example, Duke's proposed doubling of CT and tripling of CC capacity additions from Duke's 2022 Plan is predicated on the construction of one or more additional out-of-state gas pipelines that are regional and outside of Duke's control. Duke is already unable to mitigate the fuel supply risk for its already under-resourced natural gas fleet.

Q: Please provide more detail and examples on the types of risks Duke is willing to assume for natural gas generation that are analogous to risks Duke argues should not be taken for other types of resources.

A: Duke's preferred portfolio effectively asks ratepayers to take the following specific risks for natural gas - and arguably also for nuclear SMR and hydrogen - while citing these same risks as reasons to not select lower and fixed-cost resources:

- Making system viability dependent on yet-to-be-built out-of-state infrastructure that has uncertain timelines and are beyond Duke's ownership or control. Duke notes that doing so for inter-state and inter-regional electric transmission capacity expansion is too risky, even though electric transmission could be wholly or partially owned by Duke and facilitate access to diverse resources with less fuel cost and volatility risk.
- Increasing reliance on out-of-state or outside-of-service-territory resources, in this case natural gas fuel, to meet electricity needs. In the 2022 Carbon Plan proceeding, and again here in this proposed CPIRP, Duke argues that increasing use of out-of-state non-fossil resources could jeopardize reliability. As noted in this testimony, neighboring states throughout the region are proposing taking the same or similar risks with natural gas, adding to the risks of Duke's already risky natural gas reliability strategy.
- Predicating affordability on a dependence on third parties to sell a resource to Duke in a regional market, in this case natural gas fuel, at the forecasted Base price, when they have no interest or incentive to do so. Unlike long-term contracts for energy

and capacity from third-party power producers, Duke will be a price taker and cannot reasonably predict that the Base price forecast will occur, nor lock-in fuel cost beyond a near-term horizon of five years or less. Figure 7 enumerates the likely additional cost to ratepayers from taking this risk with natural gas. Duke ignores this risk while claiming that long-term contracts with renewable energy generators and battery storage owners is too risky, even though these contracts can be vetted through a procurement process.

- Asking the Commission to approve power plant construction before specific infrastructure, in this case gas pipelines, have been planned and approved to ensure those power plants will be used and useful. In contrast, Duke has placed an artificial cap on planned solar capacity additions to conform to Duke's own transmission plan.

In short, this unequal application of risk to favor natural gas (as well as the non-commercial resources of nuclear SMR and hydrogen), combined with Duke's placement of artificial planning constraints on non-fuel resources that could hedge and mitigate this risk through resource diversification, is evidence of the two planning biases identified here.

Q: Please explain how these planning biases play out in Duke's proposals.

A: First, Duke relies on third parties to build regional pipelines that Duke will not own in a process that is outside of Duke's control. Second, as shown in this testimony, Duke's fleet in the original P3 portfolio lacks sufficient fuel supply to run at peak capacity. And yet, in the preferred P3 Fall Base portfolio Duke doubled the number of proposed gas CC units, from three to six, on the assumption that the MVP Southgate and a future Gulf Coast pipeline would both be built and available to supply Duke's fleet at Duke's forecasted Base prices through 2049. Third, building gas plants before third parties build the infrastructure to supply fuel to those plants puts Duke's ratepayers at a significant disadvantage in negotiating fuel price, a cost that is passed through 100% to ratepayers. Fourth, depending on others to build regional infrastructure and honor firm fuel transmission contracts is riskier than contracting with a third-party solar or solar-plus-storage facility, because those facilities do not require gas supply, which has an unreliable history in the Southeast when it is needed most.

If the Commission allows the Plan to adopt fuel demand before fuel supply as a planning principle, setting a precedent for elevated cost and reliability risk tolerance, then the preferred portfolio should equally apply this level of risk to selection of all other resources, which by the Plan's own words it currently does not. Doing so would likely lead to a potentially very different preferred portfolio mix, compliance timeline, and potentially lower total net present value of generation portfolio and transmission capital and operating expenses that could be recoverable from ratepayers. Specifically, additional alternative renewable, battery storage, efficiency and demand response, and offshore wind resource options could all be mostly or entirely within Duke's control and located in-state or nearby offshore. Because these resources are fixed-cost in that they do not require fuel, they are an effective means of mitigating the gas costs risks described in our testimony. The resulting diversification would reduce North Carolina's dependence on delivery of out-of-state natural gas fuel and the construction of related infrastructure.

VIII. Conclusion.

Q: What are your conclusions regarding ratepayer risks from increased reliance on natural gas for electric generation in the Carolinas?

A: The lack of reliable natural gas infrastructure in the Carolinas combined with increased ratepayer costs from (1) increased utility reliance on natural gas fuel as fundamental price projections rise, (2) global market exposure to higher prices and increased volatility from geopolitical events and rising global demand, and (3) regional gas supply constraints and disruptions, each add significant costs and risks not adequately included or weighed in the CPIRP's comparison of non-carbon alternatives. In addition to the exorbitant fuel risk, investing billions of dollars in long-life natural gas assets in rate-base puts a huge weight around the necks of ratepayers that will need to be repaid on top of the next generation of carbon-free resources that will still be necessary to achieve carbon neutrality by 2050. Accounting for those ratepayer impacts will result in a different portfolio of resources, including a much higher percentage of fixed-cost, fuel-free resources.

Q: Does this conclude your testimony at this time?

A: Yes.

DUKE ENERGY CAROLINAS, LLC & DUKE ENERGY PROGRESS, LLC

Request:

Please refer to page 45 in Appendix C (Quantitative Analysis) of the 2023 Carolinas Resource Plan, where it states, "To account for potential physical and economic constraints of natural gas to the Companies' service territories, the Companies limit operations of some generation units to coal and ULSD during times of potentially limited supply and price volatility." Please explain how this limitation was modeled in EnCompass.

Response:

To represent potential physical and economic constraints of natural gas to the Companies' service territories, the Companies limited operations of all DFO units to coal and all CTs to ultra-low sulfur diesel (ULSD) for the month of January inside of Encompass. This limit was input into the model by using the minimum and maximum blend % inputs on each DFO and CT resource.

Responder: Thomas Beatty, Senior Engineer

CERTIFICATE OF SERVICE

The undersigned for Clean Energy Buyers Association hereby certifies that she served the foregoing Direct Testimony and Exhibit upon the parties of record in this proceeding by electronic mail as set forth in the Service List for such docket maintained by the NCUC Chief Clerk's Office.

This 28th day of May, 2024.

/s/ Alicia Zaloga

Alicia Zaloga