NEW ENERGY ECONOMICS
DATA-DRIVEN DECISIONS

Natural Gas Procurement, Hedging, and Regulatory Cost Recovery

An Integrated Analysis of Supply Contracts, Pipeline Dependence, and Natural Gas Cost Dynamics within Duke Energy's System

MARCH 2026

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I. Introduction

A. Purpose of Research

This paper examines how Duke Energy procures, transports, and stores natural gas for power generation across its regulated utilities. The goal is to trace the physical and financial flow of natural gas from upstream production to final combustion and to clarify how costs and risks are distributed among suppliers, transporters, and customers. The analysis relies on verifiable data derived from regulatory filings, emphasizing cost structure, contract design, and regulatory oversight rather than speculative interpretations. Resolving the opacity of natural gas procurement, transport and storage in the current systems, contracts and the costs involved overcomes the major barrier preventing sufficiently complete and accurate understanding of the cost of generating electricity with natural gas. Specifically, with greater clarity it becomes possible to comprehensively quantify the cost components and economic risks of natural gas fuel for electric generation, analyze current and proposed costs and risks of generating electricity using that natural gas fuel, and to economically analyze and compare Duke Energy's use of natural gas for electric generation to other supply and demand side electricity resources.

B. Context and Motivation

Understanding Duke's economic costs and risks is a necessary pre-requisite to an accurate economic analysis of Duke's resource planning options going forward. Natural gas represents a major component of Duke Energy's historical and current generation cost and directly influences retail electricity rates under state fuel-adjustment mechanisms. Delivered gas prices in Duke's service territories, particularly in the Carolinas and Florida, often exceed benchmark Henry Hub prices due to transportation constraints and regional basis premiums along Zone 5 of the Transcontinental Gas Pipe Line, commonly referred to as the 'Transco' pipeline. Because Duke's electric utility subsidiaries, including Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP), operate under pass-through fuel-cost recovery mechanisms, decisions about procurement, transportation, and hedging translate directly into customer bills.

Understanding how natural gas moves, who owns it, who transports it, and where costs accumulate is critical for evaluating both operational efficiency and consumer impact. This analysis provides a map of molecules and money, illustrating the interplay between contract design, infrastructure limits, and regulatory cost recovery.

This analysis is timely because DEC and DEP combined increased their annual natural gas purchase volumes by 70% from 2017-2024 (*Table 1)*, their natural gas fleet is currently short on firm transportation (FT) capacity in-service, and Duke is seeking approval of its proposal to expand gas fleet capacity, fuel purchases, and introduce LNG as a physical hedge. In the Carolinas, the majority of Duke's preferred gas fleet capacity expansion is proposed for 2026 through 2033 with one last addition of combined cycle (CC) and combustion turbine (CT) capacities in 2040.[1] *Figures 1 and 2* from Duke's 2025 proposal show expanding natural gas generation in both terawatt hours (TWh) and as a proportion of the system energy mix to a peak of about 49% of the energy mix in 2034, then reducing natural gas energy generation to 40% of system energy by 2040.[2]

Year	DEC (MMBtu)	DEP (MMBtu)	Carolinas Combined (MMBtu)	Percent Change in combined MMBtu since 2017 (%)
2017	77,966,170	162,118,314	240,084,484	
2018	123,275,917	181,301,927	304,577,844	27%
2019	120,289,258	155,524,608	275,813,866	15%
2020	131,032,933	157,197,155	288,230,088	20%
2021	181,967,967	157,902,744	339,870,711	42%
2022	244,735,641	181,934,324	426,669,965	78%
2023	217,645,488	163,659,388	381,304,876	59%
2024	236,822,757	170,348,224	407,170,981	70%

Table 1. Annual DEC and DEP gas purchase volumes and growth (2017-2024)

[1] Duke Energy. Verified Petition for Approval of 2025-2026 CPIRP, Appendix I at 1-2 and Appendix C, Tables C-49 and C-50 at 97.

[2] Duke Energy. Verified Petition for Approval of 2025-2026 CPIRP, Appendix C, Figures C-14 and C-15 at 89-90. *EIA Form 923* provides monthly utility-level data on fuel receipts, quantities, and average fuel costs, serving as the primary dataset for this analysis.

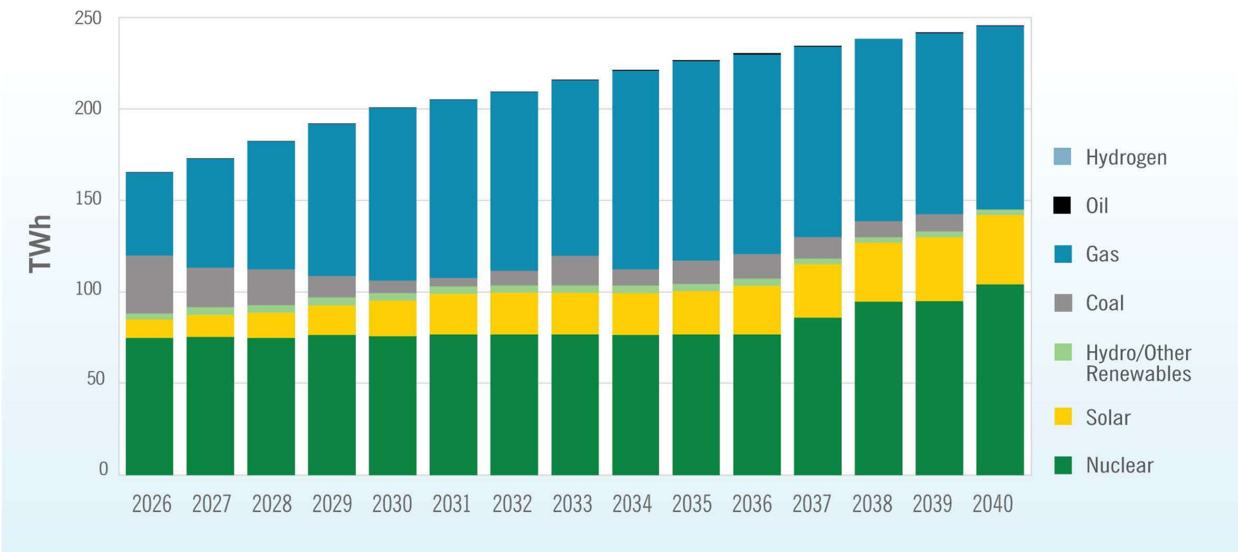

Figure 1. Duke Energy's proposed annual system energy mix by fuel type through 2040 (TWh) for combined DEC and DEP (2025 CPIRP Figure C-14)

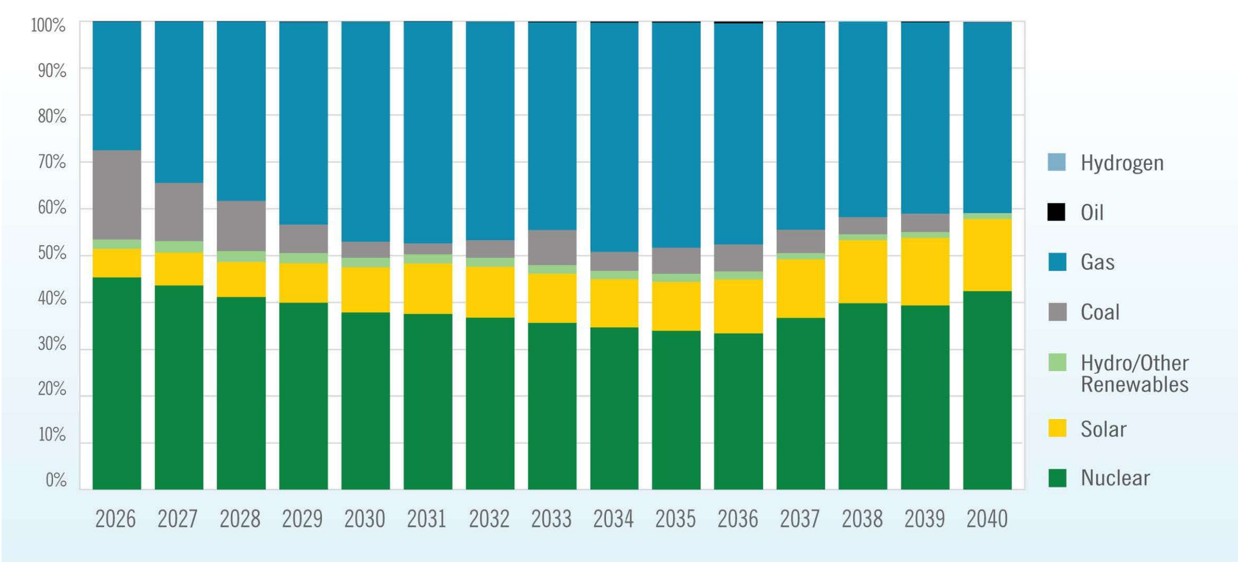

Figure 2. Duke Energy's proposed combined DEC/DEP annual energy mix by fuel type as a percent of total system generation through 2040 (2025 CPIRP Figure C-15)

C. Scope of the Analysis

This paper proceeds in five parts:

1. **Supply Chain and Contract Structure** –tracing the flow of natural gas from upstream producers to Duke's power plants and identifying ownership transfer points and contractual relationships.
2. **Procurement and Cost Formation** – detailing the types of contracts governing supply, transportation, and storage, and explaining how these costs accumulate into the final delivered fuel price.
3. **Hedging Strategy** – analyzing Duke Energy's financial derivatives program, evaluating its regulatory framework, performance, and constraints.
4. **LNG Procurement and Storage** – distinguishing between short-term just-in-time procurement for power generation and DEC and DEP's proposed introduction of 'enhanced LNG.'
5. **Regulatory Oversight** – presenting discovery and policy questions aimed at improving transparency, oversight, and ratepayer protection.

Together, these sections offer a verifiable account of Duke's natural gas procurement and risk management practices and relevant information from DEC and DEP's proposed resource plans.

D. Key Terms and Sector Terminology[3]

To assist readers unfamiliar with natural gas sector practices, several frequently used terms are defined below along with some relevant regional and electricity sector information:

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[3] These key terms definitions come from the following sources:
Sprague Energy. (n.d.). *Natural gas glossary.* Retrieved January 2026, from https://www.spragueenergy.com/natural-gas-glossary/
S&P Global Commodity Insights. (n.d.). *Glossary.* Retrieved January 2026, from https://www.spglobal.com/commodityinsights/en/our-methodology/glossary
Arizona Corporation Commission – Utilities Division. (n.d.). *Gas terminology.* Retrieved January 2026, from https://azcc.gov/utilities/industry-types/gas/terminology
PCI Energy Solutions. (2023, October 3). *The complete guide to streamlining natural gas scheduling.* Retrieved January 2026, from https://www.pcienergysolutions.com/2023/10/03/the-complete-guide-to-streamlining-natural-gas-scheduling/

- **Pipeline Tariffs:** FERC-approved transportation charges on interstate pipelines, including reservation fees, usage fees, imbalance penalties, and fuel retainage percentages established in each pipeline's tariff.
- **Basis:** The price spread between a local delivery point (e.g., Transco Zone 5) and the Henry Hub benchmark. Basis reflects regional transportation constraints, market liquidity, and supply–demand conditions.
- **Nomination Cycles:** Standardized daily scheduling windows during which shippers request pipeline flows. Pipelines offer Timely, Evening, and multiple Intraday cycles for next-day or same-day adjustments. The natural gas scheduling day begins at 10:00am ET. This is out of sync with the electricity trading day which typically begins at midnight ET.[4]
- **Percentage-of-Burn Contracts:** Supply agreements where a supplier delivers a fixed share of the utility's forecasted natural-gas usage. Seasonal structures align procurement volumes with expected load variations.
- **Dekatherm (Dth) / MMBtu:** Standardized units of natural gas energy content used for pricing, billing and reporting. One Dth equals one million British thermal units, or MMBtu.
- **Pooling Stations:** Pipeline aggregation points—such as Transco Stations 85 and 165—where gas from different suppliers is combined and redirected to downstream markets.
- **Delivery Pipelines:** Intrastate or interstate pipelines that deliver gas to end-use facilities. Examples include the Cardinal Pipeline in North Carolina, which transports gas to power plants and distribution systems.
- **Daily Nomination, Confirmation, and Balancing:**
  - *Nomination:* A shipper submits a request for daily transport volumes.
  - *Confirmation:* Pipeline operators verify volumes with upstream and downstream parties.
  - *Balancing:* Pipelines reconcile scheduled versus actual deliveries; deviations may be subject to tariff-defined penalties.
- **Firm Transportation (FT):** Reserved pipeline capacity available to the shipper every day under the terms of the tariff.

[4] Duke Energy. Verified Petition for Approval of 2025 CPIRP, App I. Duke notes this misalignment, fuel security challenges, a need for 'new infrastructure enabled tools,' and discusses a subset of the potential solutions.

- **Interruptible Transportation (IT):** Pipeline capacity used only when available after all firm nominations have been scheduled.
- **Maximum Daily Quantity (MDQ):** The maximum volume a shipper is contractually permitted to transport per day under a given transportation agreement.
- **Receipts and Deliveries:** The points where gas enters or exits a pipeline system, and where custody or ownership typically transfers.
- **Fuel Retainage:** A percentage of transported gas retained by the pipeline to cover compressor fuel and system losses, as specified in the tariff.
- **Derivatives:** Financial instruments—including fixed-for-floating swaps, futures, and options—used to manage exposure to natural-gas price volatility. Public filings describe Duke's use of derivatives for hedging but do not disclose contract-specific structures.

E. Methodology and Data Sources[5]

This study draws exclusively on publicly available filings and standardized federal data that document Duke Energy's procurement, transportation, and cost-recovery activities. These include:

1. **Duke Energy Corporation's SEC Filings** — *Form 10-K for the fiscal year ended December 31, 2024* and *Form 10-Q for the quarterly period ended June 30, 2025.* These reports provide detailed disclosures across Duke's natural gas and electric operating companies on natural gas procurement costs, derivative positions, long-term transportation and storage commitments, and subsidiary-level regulatory restrictions. They also identify Duke's ownership interests via Piedmont Natural Gas in storage facilities such as **Pine Needle LNG** and **Hardy Storage**, which are not used to deliver fuel for DEC or DEP's electricity generation in the Carolinas.

[5]Duke Energy's detailed procurement, cost, transportation, and storage disclosures are available in its fiscal year 2024 Form 10-K and June 30, 2025 Form 10-Q, filed with the U.S. Securities and Exchange Commission. https://www.sec.gov/edgar/search/
Transcontinental Gas Pipe Line Company, LLC. (2025). Index of Customers. Williams 1Line. Retrieved [month day, year], from https://www.1line.williams.com/Transco/info-postings/index-of-customers.html
Plant-level natural gas fuel receipts, consumption, and cost data are available through the U.S. Energy Information Administration's Form 923 Power Plant Operations Report. https://www.eia.gov/electricity/data/eia923/

2. **Federal Energy Regulatory Commission (FERC) Filings** — *Index of Customers (IOC)* data, which list Duke's firm and interruptible transportation contracts, including contract numbers, maximum daily quantities (MDQ), expiration dates, and pipeline zones. These filings enable tracing Duke's transportation entitlements and regional dependence on Transco Zones 4 and 5.
3. **U.S. Energy Information Administration (EIA) Data** — specifically, *EIA Form 923*, which provides plant-level fuel receipts and cost information used to quantify Duke's natural gas expenses and compare them with other utilities in North and South Carolina. This dataset underpins the empirical sections on fuel cost trends and supplier structure.

Each of these data sources is publicly verifiable and directly supports the paper's analytical findings. No proprietary or unverifiable information is used. For this reason, the information and analysis presented here is a reasonable representation of what a person or entity lacking access to confidential market or utility planning information may be able to know and understand about Duke Energy's natural gas procurement, hedging, and regulatory cost recovery for electric generation.

F. Contribution of Research

This paper integrates Duke Energy's financial disclosures, federal regulatory records, and market data into a unified analytical framework that links fuel procurement to delivered costs and regulatory outcomes. It demonstrates how layered contracts—covering supply, transportation, and storage—combine to form total fuel expenditures, and how hedging and pass-through rules affect ratepayer exposure. Beyond description, the paper provides a foundation for regulatory oversight and discovery. It identifies specific information gaps—such as undisclosed hedge structures, pipeline concentration risks, and LNG storage utilization—and proposes structured questions that regulators and advocacy organizations can use to evaluate procurement prudence and transparency. In doing so, the research advances both academic and practical understanding of how Duke Energy's natural gas procurement system operates relative to state and Federal regulatory frameworks, illuminating the financial mechanisms that shape customer fuel costs and utility risk management that, in turn, partially shape the modern energy transition.

II. Upstream Production and Marketing

Natural gas enters Duke Energy's system at the production stage, where upstream suppliers extract and sell gas under standardized industry contracts. Duke Energy does not directly own or operate gas wells; rather, it procures natural gas from a range of producers and marketers through both long-term and short-term supply agreements that specify delivery points, pricing mechanisms, and contracted volumes.[6]

These supply contracts are generally categorized as either fixed-price or index-based arrangements. Fixed-price contracts provide cost predictability, allowing the company to stabilize its fuel expenses for budgeting and rate case filings. In contrast, index-based contracts link purchase prices to published market benchmarks such as Henry Hub or Transco Zone 5, with adjustments reflecting locational and transportation differentials.[7] Title to the natural gas typically transfers to Duke or to its designated shipper at the receipt point on interstate pipeline systems, including Transcontinental Gas Pipe Line (Transco) and Southern Natural Gas (SNG), where Duke assumes ownership and financial responsibility for the commodity.

Once title transfers, the gas flows through the interstate pipeline network under Duke's transportation agreements. These pipelines, regulated by the Federal Energy Regulatory Commission,[8] act as transporters rather than owners of the commodity. Under these transportation agreements (sometimes called precedent agreements), Duke pays a combination of reservation charges to secure firm capacity and usage charges based on the actual volume transported. Duke's public filings show that the company holds a mix of firm and interruptible transportation agreements. Firm contracts guarantee access to pipeline capacity, while interruptible contracts can be used when unused capacity remains after firm nominations. This structure provides the ability

[6] Duke Energy's 2024 Form 10-K outlines its fuel procurement strategy and the structure of its natural gas purchase agreements under federal and state regulation.
[7] Index-based contracts use benchmarks such as Henry Hub and Transco Zone 5, published by independent pricing agencies, to reflect current market values for natural gas.
[8] The Federal Energy Regulatory Commission (FERC) regulates interstate natural gas pipelines, establishing tariffs and capacity rules that govern transportation service under the Natural Gas Act.

to schedule additional volumes when pipeline conditions permit, though the filings do not describe how Duke determines the appropriate mix or how often interruptible capacity is utilized.

At this upstream stage, the commodity cost represents the first component of the total gas supply chain. Each unit of gas purchased at the wellhead subsequently accrues incremental costs from transportation and balancing services before it reaches the distribution system or "burner tip" of a natural gas combined cycle or combustion turbine facility. Duke's SEC filings indicate that natural gas commodity and transportation costs are recovered through state-approved fuel adjustment mechanisms. These disclosures also note that certain transportation and service arrangements involving Duke's natural gas subsidiary Piedmont Natural Gas (PNG) support deliveries to Duke's electric generation plants. However, public filings do not itemize which specific PNG-related costs flow into electric fuel charges, nor do they describe which PNG costs, if any, are recovered instead through general rate cases. As a result, the detailed cost components included or excluded from fuel-clause recovery cannot be determined or quantified with clarity and certainty from publicly available information.[9]

III. Types of Contracts Used by Utilities for Gas Procurement

Natural gas procurement by vertically integrated electric utilities such as DEC, DEP and Duke Energy Florida (DEF) follow a multilayered contractual framework that governs both the physical movement of gas and the corresponding financial transactions across the supply chain. Each contractual layer from wellhead production to retail delivery establishes terms that define ownership transfer, cost allocation, and service reliability. These agreements generally fall into three main categories: supply, transportation, and storage. Collectively, they determine how utilities manage commodity exposure, transportation risk, and compliance under federal and state oversight.

[9] The quarterly filings describe Duke's fuel cost recovery process under subsidiary-level Purchased Gas Adjustment (PGA) mechanisms authorized by state commissions.

A. Supply Contracts

Supply contracts specify the terms under which natural gas is purchased from upstream producers or marketers, including the pricing mechanism, contract duration, and delivery location. For Duke Energy, these agreements are typically executed by its regulated operating subsidiaries—such as Duke Energy Carolinas, Duke Energy Progress, and Duke Energy Florida—rather than by the holding company itself. Together, these contracts provide the essential link between commodity market benchmarks (e.g., Henry Hub and Transco Zone 4 and Zone 5 indices) and the physical gas deliveries that ultimately serve Duke's power plants and distribution systems.[10]

Fixed-Price Contracts. Fixed-price contracts establish a predetermined price for gas over a specified term, typically one month to one year, for either prompt or future delivery regardless of market fluctuations. They are primarily used to hedge against price volatility, ensuring predictable fuel cost budgeting for electricity generation. Duke Energy's 2024 Form 10-K confirms that the company enters into a range of hedging instruments, including fixed-price contracts, forwards, and options to hedge forecasted fuel and natural gas requirements for generation, mitigating exposure to commodity price fluctuations.[11] Such arrangements stabilize costs during volatile periods but can limit potential savings when market prices decline. Utilities often employ a laddered hedging strategy, layering fixed-price contracts of varying maturities to smooth exposure over time.

Index-Based Contracts. Index-based contracts tie gas prices to publicly reported benchmarks such as Henry Hub or Transco Zone 5, with added transport differentials reflecting pipeline tariffs and location adjustments. These agreements maintain market alignment but expose utilities to short-term volatility and basis risk (the price spread between local delivery zones and the benchmark hub) (FERC, 2023).[12] In Duke's service territories, index-based gas supply contracts typically reference a published benchmark price—such as Henry Hub or a regional index like Transco Zone 5—plus applicable transportation and basis adjustments. When a contract is tied to

[10] Duke Energy's 2024 Form 10-K details the company's upstream procurement framework and its reliance on long-term and short-term supply agreements.
[11] Quotation from Duke Energy's Form 10-K (FY 2024) confirming the use of hedging contracts to manage natural gas price exposure.
[12] The Federal Energy Regulatory Commission (FERC) Form 552 tracks annual natural gas transactions, including volumes and price indices such as Henry Hub and Transco Zones 4 and 5.

Henry Hub, the delivered price reflects the Hub index **plus** the prevailing Zone 5 basis. As a result, if Henry Hub prices fall while the Zone 5 basis widens due to transportation constraints, the net delivered price may still increase. When contracts reference a regional index directly, the delivered price incorporates these basis movements within the posted Zone price itself.

Public filings do not identify which specific index each of Duke's supply contracts uses, but the filings confirm that Duke procures gas through a mix of fixed-price and index-based arrangements. The use of index-based pricing exposes customers to changes in regional basis values, which in the Southeast can be significant due to pipeline congestion on the Transco system. This dynamic explains how delivered costs can rise even in periods when national benchmark prices decline.[13]

Percentage-of-Burn Contracts. Percentage-of-burn agreements commit a supplier to deliver a fixed share of a utility's forecasted gas consumption over a defined period. For example, a utility may contract for 70%–80% of its expected monthly or seasonal burn under a POB arrangement, with the remaining share procured through daily or spot markets. Unlike fixed-price contracts (which lock in a price for a specified volume) or index-based contracts (which tie pricing to published benchmarks), POB structures scale delivered volumes with actual load. This reduces the risk of significant over- or under-procurement in periods when consumption deviates from forecasts.

Hypothetical Example:

"If a plant expects to burn 1,000,000 MMBtu in January, an 80% POB contract would commit the supplier to deliver up to 800,000 MMBtu. If actual consumption rises to 1,200,000 MMBtu due to colder weather, the supplier's obligation increases proportionally, with remaining volumes purchased in the spot market. If consumption falls, contracted volumes decrease accordingly. This load-following mechanism distinguishes POB arrangements from fixed-volume contracts."

Public filings indicate that Duke uses a mix of long-term and shorter-term supply arrangements, including percentage-of-burn structures. However, these filings do not disclose contract-level details, such as the specific indexation method, volume caps, or geographic allocation of POB

[13] Zone 5 pricing and constraints are explained in Section IV (5).

volumes. The precise design of Duke's POB agreements therefore cannot be determined from publicly available materials.

Filings also note that Duke staggers its supply agreements across multiple years to reduce exposure to contract-expiration risk. While this approach is described within Duke's enterprise risk-management framework, the specific structure of individual POB agreements is not publicly reported.[14]

B. Transportation Contracts

Transportation contracts grant Duke Energy the right to move gas through interstate pipelines between designated singular receipt and delivery points. These agreements are regulated under the Federal Energy Regulatory Commission (FERC) pursuant to the Natural Gas Act and disclosed in the FERC Index of Customers (IOC) filings, which provide public data on shipper names, contract numbers, maximum daily quantities (MDQ), and expiration dates (FERC, 2024).[15] In Duke's service territories in North Carolina and South Carolina, Transco serves as the major transportation provider for natural-gas deliveries destined for electric generating plants.[16] Duke Energy Florida also holds a firm transportation agreement with Transco under Rate Schedule FT, though based on the public documents reviewed for this report, it is not possible to identify Transco's share of the transportation capacity serving Duke Energy Florida. This paper is centrally focused on natural gas for electric generation and does not define or describe the type of contract service Duke's natural gas subsidiary PNG would enter into with its gas customers, which is referred to as **firm service**.

Firm Transportation (FT). Firm Transportation service provides Duke electric subsidiaries with guaranteed daily pipeline capacity up to the contract's Maximum Daily Quantity (MDQ) and

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[14] Duke's filings emphasize risk mitigation through staggered contract expirations to reduce exposure to simultaneous renewals.

[15] The FERC Index of Customers (IOC) lists all interstate pipeline transportation agreements under FERC jurisdiction.

[16] Duke Energy. Verified Petition for Approval of 2025 CPIRP, Appendix I at 3, from https://starw1.ncuc.gov/NCUC/PSC/PSCDocumentDetailsPageNCUC.aspx?DocumentId=4eb98dc3-1183-4682-a889-9534f775d73d&Class=Filing

receives the highest scheduling priority in all nomination cycles, as specified in Transco's tariff (GT&C § 3). Under FT service, shippers typically pay two distinct transportation charges:

1) a *reservation charge* based on contracted MDQ, which is owed regardless of actual flows, and
2) a *usage or volumetric charge* for each unit of gas transported when the shipper actually flows gas.

These transportation charges are separate from the **commodity cost** of the natural gas itself, which the utility purchases from suppliers under fixed-price or index-based contracts. Thus, total delivered gas cost includes:

1) FT reservation charges,
2) FT volumetric transportation charges (when gas flows), and
3) The underlying gas commodity price

FT service does not affect the commodity price; it governs the terms of transportation, not the purchase of the gas itself. This scheduling priority is critical for Transco Zone 5—covering the Carolinas and Virginia—where pipelines are constrained and high power-sector demand contributes to persistent basis premiums over Henry Hub, shown in *Figure 4*. Duke's firm transportation agreements, including contract numbers, MDQ levels, receipt and delivery points, and expiration dates, are summarized in Appendix A[17]

Enhanced Firm Transportation (EFT) is a new but not yet clearly defined service that Duke Energy Carolinas has contracted with MVP Southgate. Duke describes EFT service as generally having 'additional flexibility and/or reliability attributes above that of traditional FT' service at a higher cost hurdle rate than FT service.[18] In this context, the hurdle rate refers to the incremental premium Duke is willing to pay above standard FT rates in exchange for enhanced operational flexibility or reliability, including increased intraday access. Duke cites a need for increased intraday natural gas transportation flexibility due to the increase in intermittent generation on the system and

[17] IOC filings from 2024 list Duke's contract portfolio across its subsidiaries—DEF, DEP, and DEC—with expirations from 2025 to 2046.
[18] Duke Energy. Verified Petition for Approval of 2025-2026 CPIRP, Appendix I at 5.

applies this higher cost hurdle rate for modeling any combined cycle plants not already approved in the North Carolina Utilities Commission (NCUC)'s 2023-24 Duke CPIRP final order.[19]

Interruptible Transportation (IT). Interruptible service allows gas movement only when unused pipeline capacity remains after firm nominations. While IT rates are lower, service is not guaranteed during high-demand periods. Because natural gas transportation for electric generation is generally managed at a system or portfolio level rather than on a plant-by-plant basis, utilities may retain some IT service to provide operational flexibility across their fleet. In practice, IT can be useful for short-term balancing or daily flow adjustments during periods of lower pipeline utilization—such as mild-weather days when overall gas demand is reduced and firm shippers nominate less than their full contracted MDQ, leaving excess capacity available at interruptible rates. However, IT is frequently unavailable during winter peaks in the Carolinas, which limits the reliability of gas and underscores the need to maintain sufficient firm transportation entitlements, particularly as recent North Carolina proceedings, including the 2024 CPIRP order, emphasize firm capacity for new gas generation.[20] Duke's Form 10-K filings state that it maintains both firm and interruptible transportation and storage contracts to support its natural gas procurement and electricity generation operations.[21]

Pipeline Contract Data. Data from FERC's IOC shows that Duke's transportation portfolio is concentrated in the Zone 4 → Zone 5 corridor, connecting Gulf Coast supply with Southeastern demand centers. Contract expirations range from 2025–2026 (DEF) to 2046 (DEC), indicating a staggered renewal schedule that supports long-term capacity planning.

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[19] Duke Energy. Verified Petition for Approval of 2025-2026 CPIRP, Appendix I at 5.

[20] NCUC Order Accepting Stipulation, Granting Partial Waiver of Commission Rule R8-60A(d)(4), and Providing Further Direction for Future Planning, Docket No. E-100, Sub 190 (Nov. 1, 2024), from https://starw1.ncuc.gov/NCUC/PSC/PSCDocumentDetailsPageNCUC.aspx?DocumentId=f56345c4-bff1-4ba0-ab47-015f51603d1c&Class=Order

[21] Duke Energy's Form 10-K (FY 2024) confirms the company maintains both firm and interruptible transportation to support generation reliability.

C. LNG and Storage Contracts

Duke Energy's natural gas subsidiary PNG utilizes both Liquefied Natural Gas (LNG) storage[22] contracts and traditional underground natural gas storage[23] to provide operational flexibility for managing intraday and seasonal imbalances. These storage arrangements enable Duke to meet demand surges and offset supply interruptions by storing gas in liquid form during periods of low demand (liquefaction) and withdrawing it as vapor during peak demand periods (regasification).

However, the conversion process—liquefying the gas, storing it, and later regasifying it—introduces additional costs and efficiency losses. These losses, although materially different from round-trip efficiency losses observed in battery storage, remain an important consideration when evaluating whether to introduce LNG storage as a balancing resource for electricity generation.

In addition to LNG storage, Duke's PNG also relies on traditional underground gas storage[24]. These contracts provide firm entitlements for Duke to inject, store, and withdraw natural gas volumes from underground reservoirs within specified contractual limits, typically over multi-year terms. Charges for underground storage usually consist of a fixed reservation fee (per dekatherm of capacity) and variable fees for actual gas injection and withdrawal, providing reliable access to gas when needed.

Firm Storage. Firm storage entitlements guarantee Duke the right to inject, store, and withdraw defined gas volumes within contractual limits, usually on a multi-year term. Charges typically include a fixed reservation fee (per dekatherm of capacity), regardless of actual capacity use, along with variable fees based on the actual injection and withdrawal of gas.

Interruptible Storage. Interruptible storage offers Duke's PNG optional access to storage when capacity is unused by firm storage subscribers. Because interruptible or non-firm services are

[22] This source discusses Duke Energy's LNG facilities and their role in ensuring supply during high-demand periods. "Liquefied Natural Gas (LNG) Plant in North Carolina" – Illumination by Duke Energy"

[23] This covers Duke's operations in traditional underground natural gas storage and how it serves as a reliable part of their distribution network. "How Energy Works – Delivering Natural Gas" – Duke Energy

[24] Provides a general overview of underground natural gas storage, including firm and interruptible contracts, and how they function within the U.S. energy system. *"Natural Gas Storage"* – *U.S. Energy Information Administration (EIA)*

lower priority and subject to curtailment when firm services are scheduled, the availability of this storage can become uncertain during high-demand periods.

If Duke Energy's electricity subsidiaries DEC or DEP build, own, and operate their own utility-owned LNG production, storage, and regasification facilities, the costs and risks associated with underutilization of facility capacity, along with ongoing operations and maintenance (O&M) risks, would be borne entirely by DEC and DEP or its customers, or both, depending on how the NCUC or the Public Service Commission of South Carolina (SC PSC) structures cost recovery. Currently, DEC and DEP pass through 100% of natural gas fuel costs to customers.

IV. Chain of Custody for Natural Gas – Duke Energy on Transco

Duke Energy's natural gas supply chain on the Transco system operates under a well-defined sequence of custody transfers, beginning with upstream producers in the Gulf Coast and Appalachian regions and extending to its natural gas–fired power plants across the Carolinas and Florida. Duke's midstream gas supply chain on the Transco system is governed primarily by long-term firm transportation agreements. For instance, Duke's Carolina utilities reported holding 434,500 Dth/day[25] of long-term firm transportation capacity on Transco under contract in regulatory testimony.[26]

A. Zone Structure and Basis Premium

Transco's network is divided into five rate zones[27], each corresponding to distance, pipeline congestion, and market conditions along the corridor. *Figure 3* describes the flow of Duke's natural

[25] South Carolina Public Service Commission, *Direct Testimony of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, reporting Duke's contracted Transco firm transportation capacity of 434,500 Dth/day, available at https://dms.psc.sc.gov/Attachments/Matter/d5e6ca0a-eef6-47f9-90bd-1f7a50d88b51

[26] FERC's 2024 Index of Customers identifies Duke's firm transportation contracts across Transco's system, showing the company's reliance on the Zone 4–5 corridor.

[27] FERC tariff filings outline Transco's five-zone rate structure and corresponding transportation costs.

gas on Transco's pipelines.[28] Zone 1 lies closest to Gulf Coast production and has the lowest transportation costs and most abundant capacity. Zone 2 extends north through southern Alabama, where transport charges rise modestly as gas moves away from supply. Zone 3 spans the mid-system corridor (Stations 50–65), offering shippers moderate-cost routing flexibility. Zone 4, anchored by Station 85, serves as the primary pooling hub feeding southeastern demand centers; recurring seasonal constraints often make it one of the most expensive system segments. Zone 5, covering the Carolinas and Virginia, is the most delivery-constrained portion of the system, where limited pipeline system capacity and high power-sector demand create persistent basis premiums.[29]

The delivered price into Zone 5 includes not only the commodity index and the Zone 4-to-Zone 5 transportation charge, but also a market-driven, time-varying basis premium that reflects downstream scarcity and congestion. This basis component is not a static or fixed contractual adder; it fluctuates daily—and at times intraday—based on system conditions. Market evidence demonstrates this volatility: RBN Energy documents single-day Zone 5 surges exceeding $7/MMBtu above Henry Hub during tight market conditions, showing that basis premiums respond dynamically to real-time system constraints.[30] Likewise, the Intercontinental Exchange (ICE) "Transco Zone 5 Basis Future" contract settles to the average of the daily price differential between Transco Zone 5 delivered gas and Henry Hub for the contract month, confirming that basis is treated by market participants as a continuously traded, market-driven spread rather than a fixed component of a transportation contract.[31] EIA further observes that forward basis swaps for hubs such as Zone 5 incorporate evolving expectations about congestion, weather, and pipeline utilization, demonstrating that basis volatility arises from market conditions rather than from forecasted congestion embedded at the time of contracting.[32]

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[28] Arbo. Map of Transcontinental Gas Pipe Line Company, LLC – System with flow diagram added by authors. Map, from https://goarbo.com/blog/if-mvp-completed-where-would-gas-go/

[29] FERC tariff filings outline Transco's five-zone rate structure and corresponding transportation costs.

[30] RBN Energy. (2022). *Flyin' High – What's Behind the Mid-Atlantic/Southeast Natural Gas Price Spikes?* https://rbnenergy.com/daily-posts/blog/whats-behind-mid-atlanticsoutheast-natural-gas-price-spikes

[31] Intercontinental Exchange (ICE). (2024). *Transco Zone 5 Basis Future* *https://www.ice.com/products/42944091/Transco-Zone-5-Basis-Future*

[32] U.S. Energy Information Administration. (2020, September 8). *Natural gas price differentials to Henry Hub narrowed at most hubs in first half of 2020.* Today in Energy. https://www.eia.gov/todayinenergy/detail.php?id=45037

As a result, Duke's delivered natural-gas price into Zone 5 reflects a composite of commodity price, tariff-based transport, and a real-time, market-responsive basis premium, which together determine the total cost of serving load in one of the most constrained segments of the Transco system.[33] Zones 4 and 5 are structurally more expensive due to greater transport distance from supply basins and capacity bottlenecks. Zone 5 functions as a premium market, where scarcity pricing prevails even when national benchmark prices remain stable. For Duke, this means that every delivered molecule carries cumulative costs from commodity procurement, long-haul transportation, pipeline congestion, and regional scarcity pricing.

B. Upstream Origin and Custody Transfer

Natural gas supplied to Duke originates from production basins that feed into Transco Zone 4 (with the Station 85 Pool in Choctaw County, Alabama, aggregating supply from the Gulf region) and Transco Zone 5 (with the Station 165 Pool in Pittsylvania County, Virginia, aggregating supply from the Appalachian Basin). At these pooling points, producers and marketers deliver gas and conduct commercial transactions in which volumes are nominated for transport, aggregated, and sold under bilateral supply contracts. Title typically transfers to Duke or to Duke's contracted suppliers at these pooling hubs, marking the beginning of Duke's custody chain within the interstate pipeline system. The pooling stations operate as commercial interchange points, where supply is acquired and ownership changes hands before the gas is transported under Duke's firm transportation agreements.[34]

- Station 85 Pool (Zone 4) serves as the principal receipt hub for Duke Energy Florida (DEF), Duke Energy Progress (DEP), and Duke Energy Carolinas (DEC).
- Station 165 Pool (Zone 5) serves as a secondary receipt hub for DEC, under its long-term Contract 9279212 (exp. 2046).[35]

[33] FERC tariff filings outline Transco's five-zone rate structure and corresponding transportation costs.
[34] Duke Energy's 2024 Form 10-K describes its gas procurement sources and pooling arrangements at Stations 85 and 165.
[35] FERC IOC filings (2024) confirm Contract 9279212 as DEC's long-term entitlement linking Zone 5 supply to Carolinas delivery points.

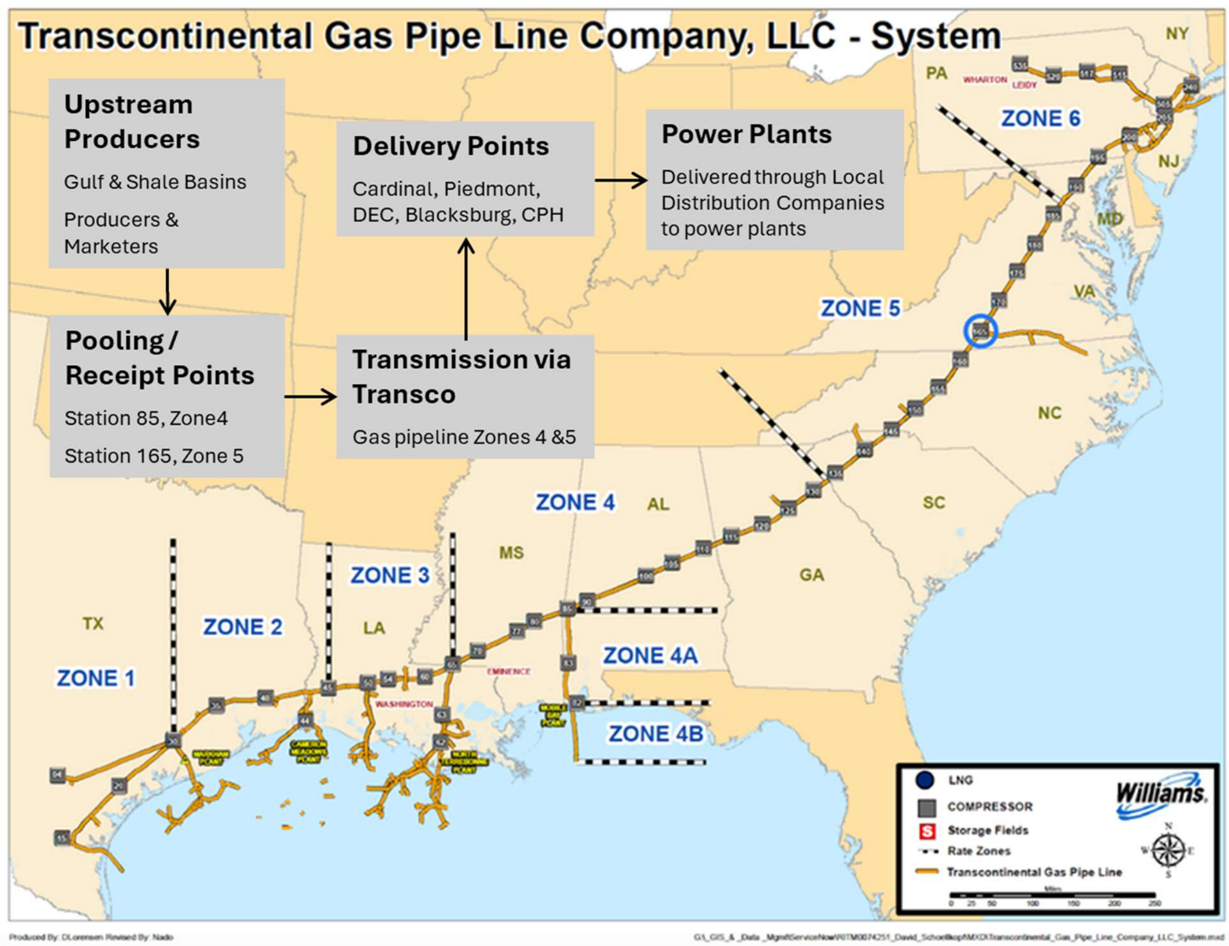

Figure 3. Transco well-head to burner tip pathway for gas procured by Duke Energy

Once title transfers, the contracting Duke subsidiary company assumes both commercial and operational risk for the gas, while Transco assumes custody as the pipeline operator responsible for transport.

C. Transmission via Transco

Following receipt, gas moves through the Transco pipeline under Duke's firm transportation entitlements, which generally secure delivery along defined route segments and zones, subject to standard contractual limitations such as force majeure[36] and upstream curtailments. Duke's

[36] Firm transportation service provides priority scheduling rights but does not ensure physical delivery under all conditions. Delivery may be curtailed due to force majeure events, operational flow orders, upstream supply interruptions, or pipeline system constraints, as illustrated by curtailments during Winter Storm

contractual flow patterns are predominantly south-to-north, moving from Zone 4 (Station 85) into Zone 5 (the Carolinas and Virginia), with a southern extension into Florida through the Coden–GS interconnect.

However, while contracts specify south-to-north movement, physical gas on Transco may flow north-to-south in the Carolinas and Mid-Atlantic markets due to growing Appalachian supply and evolving regional demand patterns. These opposing contractual and physical flow directions are made possible through displacement and backhaul mechanisms, in which Duke's scheduled volumes are fulfilled through offsetting shipper transactions rather than the literal movement of molecules along the contracted path. Because there is no information about these displacement arrangements in the documents covered in this paper, this analysis includes a suggested set of questions in Chapter VIII focused on backhaul practices, counterparty identification, and the extent to which displacement affects Duke's transportation costs and basis exposure. Duke has just recently stated that 'a Transco system constraint at Station 160 in Rockingham County, N.C., currently limits gas supply flowing southward from Virginia into the Carolinas' contractual flow patterns.[37]

A list of Duke Energy's firm transportation contracts on the Transco pipeline, including delivery paths and contract terms—is provided in the Appendix. Each contract provides firm capacity along a defined path, ensuring uninterrupted delivery even during constrained periods. This reliability, however, comes with cost exposure to Zone 5 basis premiums, as downstream congestion elevates delivered prices relative to Henry Hub.[38]

Elliott. The Williams Companies, *Winter Storm Elliott: Natural Gas System Performance and Lessons Learned* (May 2023), available at https://www.williams.com/wp-content/uploads/sites/8/2023/05/Transco-Paper-Final-DIGITAL.pdf.

[37] Duke Energy. Verified Petition for Approval of 2025-2026 CPIRP, Appendix I at 3.

[38] Basis premiums reflect the differential between Zone 5 delivered gas prices and the Henry Hub benchmark due to capacity scarcity.

D. Delivery and Final Custody

At the downstream end, gas exits the Transco system at designated delivery points—Cardinal, Piedmont, Duke Carolinas, Blacksburg, CPH (Progress), and Coden-GS (Florida). Both DEC and DEP must deliver their gas through a Local Distribution Company (LDC). Custody officially transfers to Duke Energy at these delivery points, after which the gas enters intrastate transmission pipelines or through city gates for final delivery by LDCs (Cardinal, Duke subsidiary Piedmont Natural Gas, and PSNC/Enbridge in North Carolina, for example) to power plants or other end-use customers.

Daily balancing of scheduled versus actual flows ensures compliance with FERC's scheduling protocols and Transco's nomination cycles, maintaining operational accuracy and regulatory compliance.[39] At this point, the custody chain terminates, and the gas is ultimately combusted at the burner tip, completing the transition from production basin to end use.

E. Molecule Flow: Incorporating MVP and North–South Flow Dynamics

The movement of natural gas on the Transco system reflects a combination of physical flow patterns, contractual rights, and regional production dynamics. According to S&P Global Commodity Insights (2024), MVP's startup now allows significant volumes of Appalachian gas to flow southward on Transco, which establishes a distinction between Duke's contractual delivery path and the physical origin of molecules arriving at its delivery points.[40] In fact, S&P Global Commodity Insights[41] explains that although Duke Energy's transportation contracts are structured as northbound deliveries from Station 85 in Zone 4 into Zone 5, the physical gas serving Duke's load may flow from either direction depending on system conditions. In recent years, the rapid

[39] FERC's scheduling protocols define daily nomination, confirmation, and balancing procedures for interstate shippers. https://www.ferc.gov/sites/default/files/2020-08/M-1.pdf

[40] S&P Global Commodity Insights. (2024). *"Appalachian Basin gas takeaway capacity rises as Mountain Valley Pipeline enters service."* *https://www.spglobal.com/commodity-insights/en/news-research/latest-news/natural-gas/061424-appalachian-basin-gas-takeaway-capacity-rises-as-mountain-valley-pipeline-enters-service*

[41] S&P Global Commodity Insights. (2024). *"Appalachian Basin gas takeaway capacity rises as Mountain Valley Pipeline enters service."* *https://www.spglobal.com/commodity-insights/en/news-research/latest-news/natural-gas/061424-appalachian-basin-gas-takeaway-capacity-rises-as-mountain-valley-pipeline-enters-service*

expansion of Appalachian Basin production—particularly Marcellus and Utica volumes entering the system in the Mid-Atlantic—has driven substantial south-to-north and north-to-south displacement flows along Transco. The recent statement by Duke regarding Transco Station 160 appears to conflict with S&P Global's information about molecule flows on the system.[42]

These flows intensified following the June 2024 in-service date of the Mountain Valley Pipeline (MVP), a 2 billion cubic feet per day (Bcf/d) pipeline delivering Appalachian gas directly into Transco at Station 165 in Virginia. MVP and the associated Equitrans Expansion Project, which added another 600 million cubic feet per day (MMcf/d) of north-to-south capacity, [43] now provide a major new pathway for discounted Appalachian supply to reach Southeast markets, including areas where Transco Zone 5 often trades at a premium. These price differentials, combined with increased takeaway capacity from Appalachia, create persistent incentives for southward displacement flows into the Carolinas, meaning the molecules ultimately delivered to Duke's delivery points may originate from the north even when the contractual path runs south-to-north. Duke recently stated the Southeast Supply Enhancement (SSE) expansion on the Transco system 'will expand the north-to-south flow capacity from the MVP terminus, enabling a pathway to redeliver Appalachian gas supply into North Carolina.[44]

Because none of the documents reviewed for this paper disclose the specific displacement or capacity-trading arrangements in aggregate or of individual Duke subsidiaries, Section VII includes questions regulators or parties to relevant proceedings in regulatory venues could ask to clarify how Duke utilizes Transco's backhaul and displacement services to reconcile contractual paths with prevailing physical flow patterns.

Deliveries terminate at delivery points such as Cardinal and Piedmont, which are located in pricing areas where basis differentials—the spread between local delivered prices and the Henry Hub benchmark—are consistently positive. These positive basis differentials reflect downstream

[42] Duke Energy. Verified Petition for Approval of 2025-2026 CPIRP, Appendix I at 3.
[43] S&P Global Commodity Insights. (2024). *"Appalachian Basin gas takeaway capacity rises as Mountain Valley Pipeline enters service."* https://www.spglobal.com/commodity-insights/en/news-research/latest-news/natural-gas/061424-appalachian-basin-gas-takeaway-capacity-rises-as-mountain-valley-pipeline-enters-service
[44] Duke Energy. Verified Petition for Approval of 2025-2026 CPIRP, Appendix I at 3.

transportation constraints and congestion costs, rather than the underlying cost of Appalachian gas at the production source.

F. Flow of Money and Gas Ownership

The flow of natural gas and associated payments proceed along two related but distinct cost pathways. First, Duke compensates upstream producers and marketers under a portfolio of physical supply contracts — including fixed-price, index-based, and other volume-linked arrangements — for the commodity itself. Second, Duke pays interstate pipelines and storage providers for transportation and storage services, which typically include a fixed reservation charge (for capacity rights) and a variable usage fee tied to actual throughput.[45]

Ownership of the gas follows the NAESB Base Contract for Sale and Purchase of Natural Gas and Transco's FERC Gas Tariff. Producers and marketers retain title until gas is delivered into Transco at designated receipt points, typically Station 85 or 165. Once received, Transco assumes custody but not ownership; it acts solely as a transporter. Duke assumes title at the receipt point and retains ownership throughout transmission, storage, and final delivery.[46]

Under Transco's General Terms & Conditions §9 (Possession of Gas) and NAESB §8.1, the pipeline functions purely as a carrier, while Duke, as shipper, bears ownership and related risk once gas enters the system. Title remains with Duke until the gas is delivered to its power plants. This separation of title, custody, and payment flows underpins Duke's entire supply chain structure, ensuring legal clarity, cost transparency, and regulatory compliance across its gas procurement and delivery operations.[47]

[45] Federal Energy Regulatory Commission. (2025). *Capacity release fact sheet: Firm vs. interruptible services on interstate pipelines.* https://www.ferc.gov/fact-sheet-capacity-release

[46] The NAESB Base Contract (2006) establishes standardized terms for natural gas title transfer and risk allocation.

[47] Transco's FERC Gas Tariff §9 (Possession of Gas) confirms that the pipeline acts solely as carrier; ownership remains with the shipper.

V. Duke's Fuel Cost and Supplier Analysis

A. Fuel Receipts and Costs Analysis

This section of the paper analyzes monthly fuel receipts and natural gas costs for Duke Energy Progress and Duke Energy Carolinas, which collectively operate in North Carolina (NC) and South Carolina (SC), over the period 2017–2024. The analysis uses plant-level data from *EIA Form 923*.[48] All reported fuel costs were converted from cents/MMBtu to $/MMBtu for comparability across utilities and over time.

The monthly trends, illustrated in *Figure 4*, show that Duke Energy's average natural gas costs closely follow regional market movements but exhibit higher volatility. Costs rose sharply during the 2022 energy market disruption, nearly reaching $16/MMBtu, before stabilizing around $4.8/MMBtu by 2024, as shown in *Figure 4*.[49] This pattern mirrors broader U.S. gas market dynamics following supply constraints and global price shocks. The monthly series also exhibits a clear seasonal pattern, but the drivers of that seasonality are more nuanced than a simple "winter peak, summer trough" driven solely by heating demand. In the Carolinas, Duke Energy is a winter-peaking utility despite also experiencing substantial summer air-conditioning loads, largely because a significant share of residential customers rely on electric resistance (strip) heating rather than gas-fired furnaces.[50] This produces elevated winter electricity demand that increases gas burn at Duke's combined-cycle plants, even though overall U.S. natural gas demand is simultaneously rising due to non-power-sector space heating, which tightens interstate pipeline capacity and raises regional delivered prices.[51] The combination of high electric heating load within Duke's service territory and high national space-heating demand creates upward winter pressure on delivered gas costs.

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[48] *EIA Form 923* provides monthly utility-level data on fuel receipts, quantities, and average fuel costs, serving as the primary dataset for this analysis.
[49] Plant-level natural gas fuel receipts, consumption, and cost data are available through the U.S. Energy Information Administration's Form 923 Power Plant Operations Report. https://www.eia.gov/electricity/data/eia923/
[50] **U.S. Energy Information Administration (EIA)**, *Residential Energy Consumption Survey (RECS)* — electric resistance heating prevalence in the Southeast. https://www.eia.gov/consumption/residential/
[51] EIA Short-Term Energy Outlook (STEO) – Natural Gas Section. https://www.eia.gov/outlooks/steo/

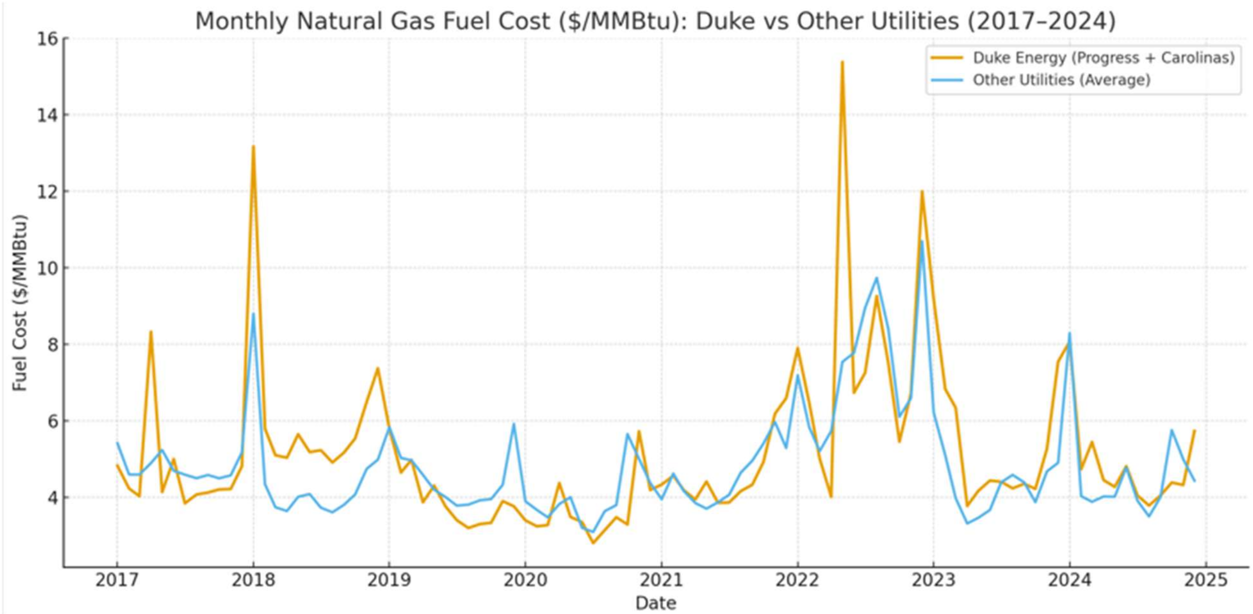

Figure 4: Comparison of Duke Energy's natural gas purchase costs with those of other utilities in North Carolina & South Carolina [52]

In contrast, summer pricing patterns reflect a different set of forces: although Duke burns substantial volumes of natural gas to serve air-conditioning demand, regional prices often ease during summer months due to lower residential/commercial gas consumption, reduced pipeline congestion, and the seasonal surge in solar generation, which increasingly offsets mid-afternoon gas-fired generation in the Carolinas.[53] Consequently, the observed "summer troughs" in the series do not imply low gas usage by Duke, but instead reflect the broader seasonal structure of U.S. natural gas markets, where winter peaks are driven by competing national heating demand and pipeline constraints, while summer prices soften under more favorable supply-demand conditions and growing renewable penetration. Interestingly, as short-duration battery storage penetration has increased in states like Texas, the already high renewable penetration has resulted in increased ability to utilize renewables and storage to serve both summer and winter peaks, lowering the cost

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[52] **Other Utilities:** *Dominion Energy South Carolina; Santee Cooper; North Carolina Eastern Municipal Power Agency (NCEMPA); North Carolina Municipal Power Agency No. 1 (NCMPA1); Greenville Utilities Commission; Fayetteville Public Works Commission (PWC); City of Laurinburg; City of Monroe.*

[53] **EIA Hourly Electric Grid Monitor** (Southeast solar rising sharply since 2018) https://www.eia.gov/electricity/gridmonitor/

of serving peak in Texas over recent years.[54] If practiced in Duke Energy's Carolinas territories, this may interrupt some of the upward cost pressures on gas described here.

On average, Duke Energy's natural gas costs remained about 10–12 percent higher than the aggregate of other North and South Carolina utilities (*Figure 5*). The higher mean cost may reflect Duke's emphasis on relying on natural gas for reliability and hedging strategies, including long-term indexed supply contracts and higher-cost pipeline zones. While cost convergence is visible in 2023–2024, the company's monthly data still suggests greater exposure to short-term market conditions than peer utilities. The rate and economic impact of any disparities can intensify when the annual gas purchase volume increases, as is Duke's situation shown in *Table 1*.

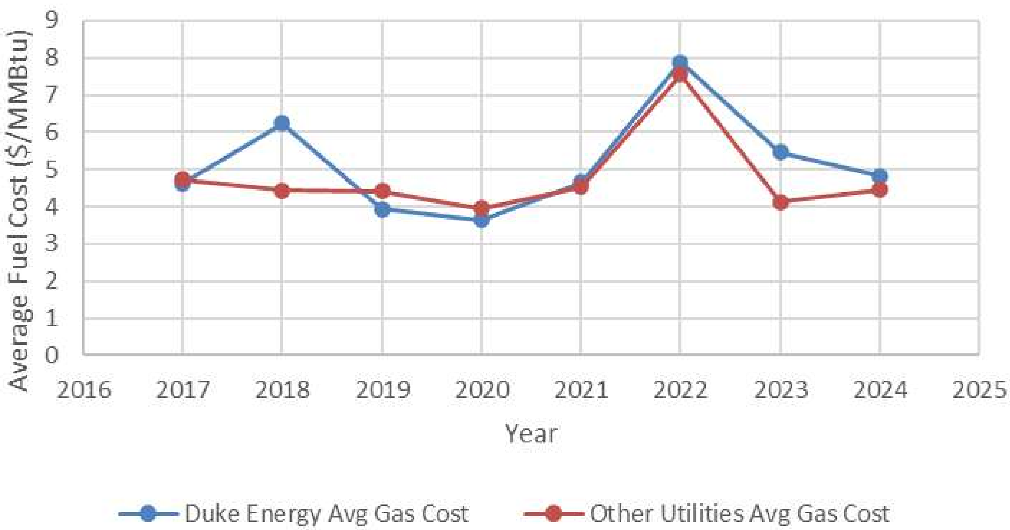

Figure 5: Average yearly fuel price ($/MMBtu, 2017-2024)

B. Supplier Structure and Procurement Strategy

The paper further examines Duke Energy's natural gas supplier relationships to understand how procurement concentration and pricing outcomes evolved between 2017 and 2024. Supplier-level data were aggregated across both subsidiaries (DEP and DEC) to determine purchase frequency

[54] Scott Madden. *Topic 5: Grid Flexibility*. https://publications.scottmadden.com/energy-industry-update-v25-i1/grid-flexibility

and average fuel cost per supplier. The scatter plot in *Figure 6* presents each supplier's number of transactions (X-axis) versus their average fuel cost ($/MMBtu) (Y-axis).

The analysis identifies a small group of firms accounting for most of Duke Energy's natural gas receipts. The five most frequent suppliers—Pacific Summit, Sequent, Twin Eagle Resource Management, BP, and Shell Energy North America—collectively represent roughly two-thirds of all transactions during the period. Among these, Pacific Summit, Sequent, and Twin Eagle provided the largest number of deliveries at relatively moderate average prices between $4.60 and $5.20/MMBtu, suggesting long-term commercial stability and favorable transport arrangements.

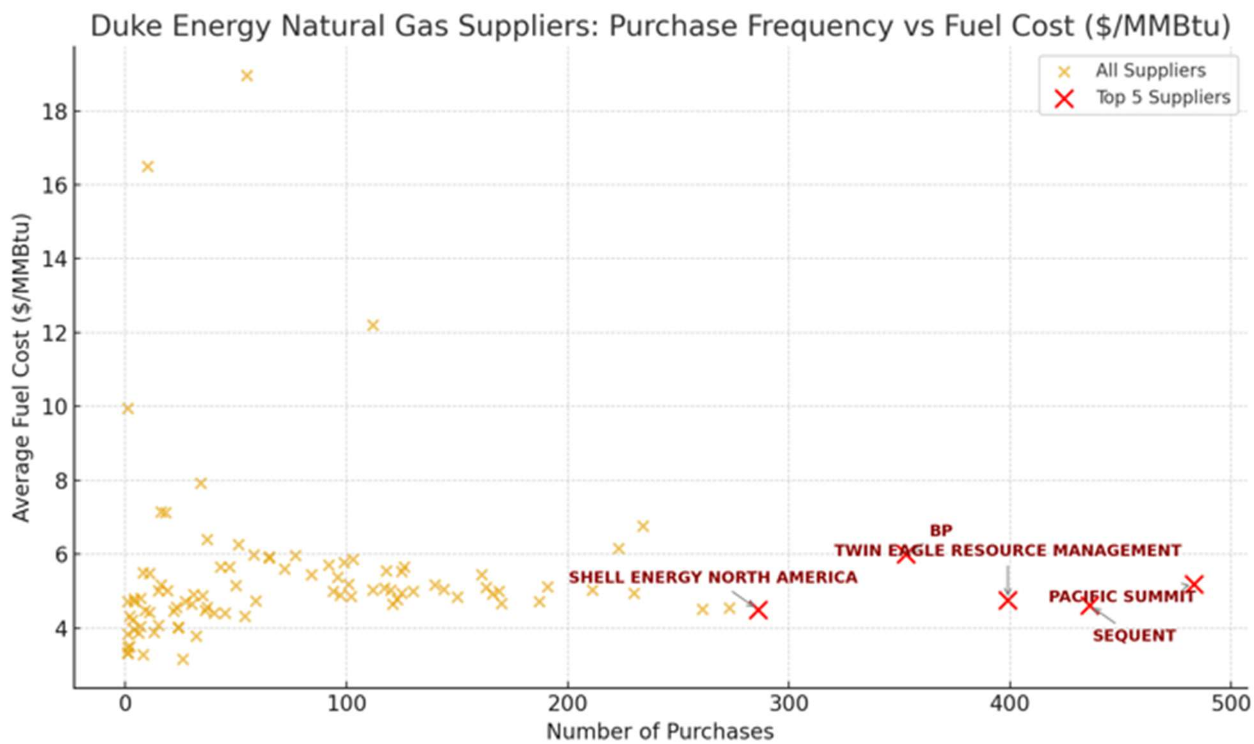

Figure 6: Duke's purchase frequency of natural gas vs suppliers (2017-2024)

In contrast, BP, Vitol and Spotlight Energy show fewer transactions but consistently higher average prices (approximately $6.00/MMBtu), likely reflecting premium supply or spot-market procurement during high-demand months. (See *Table 2*).

Many suppliers transact occasionally at very low or very high prices, but they represent tiny volumes and therefore contribute little to Duke's overall fuel cost exposure. These transactions are typically episodic, reflecting short-term balancing needs, plant-specific dispatch conditions, or opportunistic spot market purchases rather than sustained procurement relationships. As a result, while such suppliers expand the observable range of prices in the data, they do not appear to materially influence Duke's average fuel costs or its exposure to gas price risk, which instead appears to be driven by a small set of high-volume suppliers.

The spatial distribution of points in *Figure 6* underscores that Duke Energy's procurement strategy relies heavily on a concentrated set of core suppliers offering more predictable pricing, supplemented by opportunistic purchases from premium traders when necessary. The moderate correlation between purchase frequency and lower fuel cost implies scale economies or preferred-shipper advantages in long-term contracting.

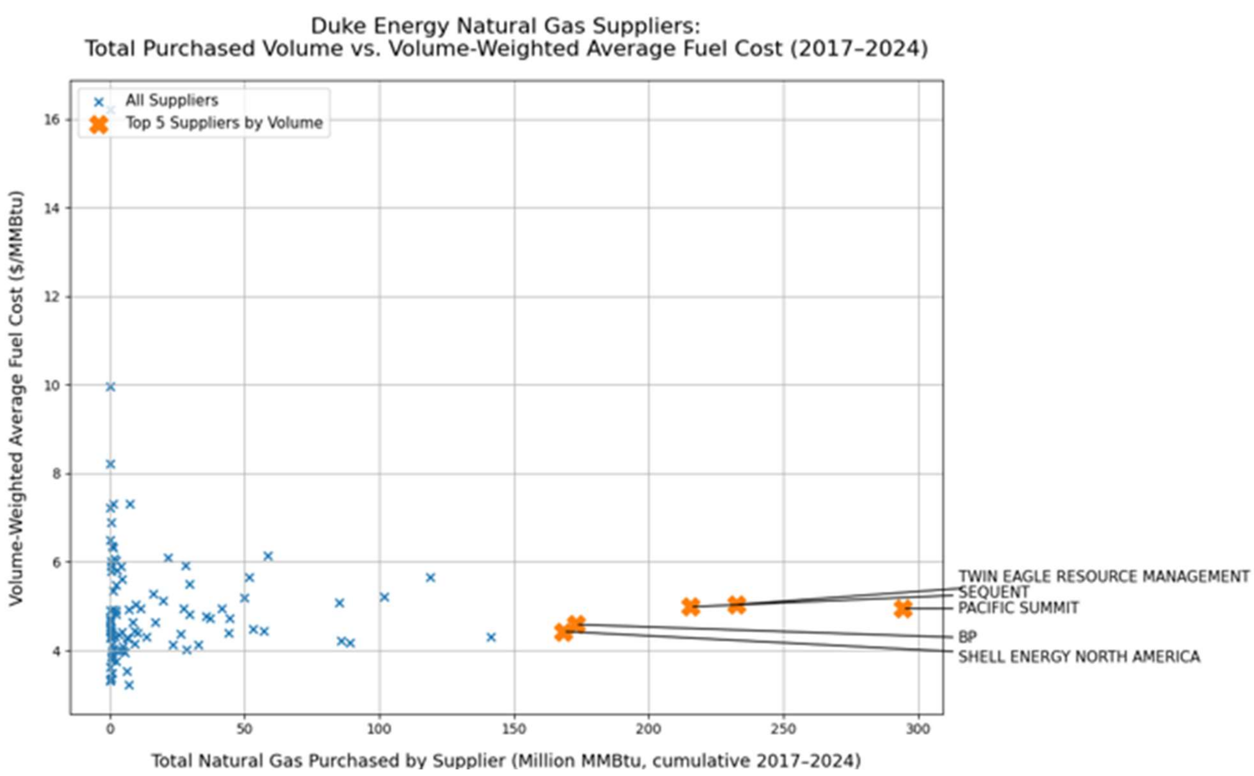

Figure 7: Duke's purchase volume of natural gas vs suppliers

Figure 7 presents Duke Energy's natural gas suppliers by total purchased volume and volume-weighted average fuel cost over the 2017–2024 period. The figure shows that Duke's largest-volume suppliers are consistently associated with above-average fuel costs, clustering in the $4.5–$5.2/MMBtu range. While a long tail of suppliers transact at lower prices, these suppliers account for relatively small volumes and therefore contribute little to Duke's overall fuel cost exposure. Together with the purchase-frequency analysis, this volume-based evidence indicates that Duke's elevated natural gas costs are driven by structural reliance on a concentrated set of higher-priced suppliers rather than by occasional high-cost transactions or short-term market volatility.

Rank	Supplier	Purchase Count	Avg Fuel Cost ($/MMBtu)
1	Pacific Summit	483	5.19
2	Sequent	436	4.62
3	Twin Eagle Resource Management	399	4.76
4	BP	353	6.00
5	Shell Energy North America	286	4.51
6	DTE Energy	273	4.55
7	Macquarie Energy	261	4.52
8	Spotlight Energy, LLC	234	6.77
9	Tenaska Marketing Ventures	230	4.94
10	Vitol	223	6.17

Table 2. Top 10 natural gas suppliers to Duke Energy (2017–2024)

The supplier analysis shows a highly concentrated procurement structure, where Pacific Summit, Sequent, and Twin Eagle Resource Management dominate Duke's supply chain. These top three suppliers account for over 50% of total transactions. Their average prices remain competitive, suggesting economies of scale and favorable transport arrangements. Higher-cost suppliers such as BP and Vitol are likely to serve peak or spot-market procurement needs, indicating a strategy of balancing between reliability and price competitiveness.

Overall, the supplier analysis reveals a hybrid procurement model anchored by stable regional traders complemented by flexible market access that supports Duke Energy's operational reliability while trying to limit extreme price exposure. This structure, combined with its observed cost dynamics, generally highlights an adaptive procurement strategy, but as *Figure 4* shows, Duke's average natural gas fuel costs have been 10-12 percent higher than Southeast peer utilities as they each grapple with the evolving volatility of U.S. and regional natural gas markets.

C. Utility Natural Gas Fuel Costs vs. Henry Hub

This analysis compares Duke Energy's and other Carolinas utilities' natural gas fuel costs to the national benchmark Henry Hub price over the period 2017–2024, to assess regional price differentials, procurement behavior, and exposure to national market volatility. Using *EIA Form 923* monthly fuel cost data,[55] natural gas cost premiums were graphed against Henry Hub prices in *Figure 8* below. The results show that both Duke and other NC and SC utilities consistently paid a premium above Henry Hub throughout most of the study period. This reflects the structural transportation and delivery cost uplifts embedded in the Transco Zone 5 and Southern Natural Gas pipeline systems that serve the region.

Duke Energy's basis series exhibits a wider range of values over time compared with the peer utilities. Several months show pronounced positive deviations, including peaks approaching or exceeding $8/MMBtu, as well as occasional negative values in which Duke's delivered cost fell below Henry Hub. These movements appear episodic rather than continuous, with sharp month-to-month changes in some periods and more moderate fluctuations in others.

The peer utilities' basis series remains closer to the Henry Hub reference line throughout the period, with fewer extreme deviations. Although this series also shows periods of elevated basis—particularly during the years 2020–2022—the amplitude of those movements is generally smaller than those observed for Duke Energy.

Both series display increased volatility during certain periods, notably between 2020 and 2022, where larger swings in basis are visible in both Duke's and peers' data. From 2023 through 2024,

[55] *EIA Form 923* monthly fuel cost data are the source for both Duke Energy and benchmark Henry Hub price comparisons in this section.

the two series appear to converge more closely in level, with basis values for both Duke and other utilities largely clustered between approximately $1 and $3/MMBtu, but Duke's basis consistently higher than the other utilities.

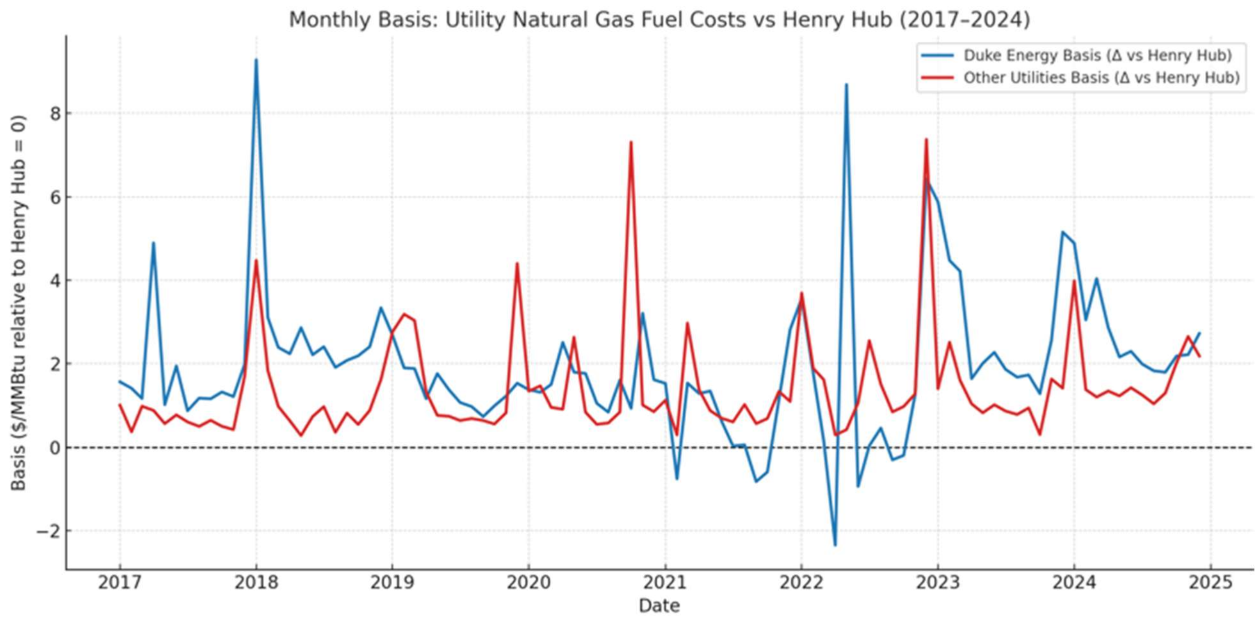

Figure 8: NC and SC utilities natural gas fuel premiums vs Henry Hub

Overall, the graph shows that natural gas fuel costs for both Duke Energy and peer utilities consistently exceed Henry Hub, with Duke's basis exhibiting larger and more frequent deviations from the benchmark than the peer group over the 2017-2025 sample period.

Although the figure itself is purely descriptive, the U.S. Energy Information Administration (EIA) provides context for understanding why basis differentials such as those shown tend to vary over time. EIA explains that regional natural gas basis premiums are primarily driven by transportation constraints, seasonal demand fluctuations, weather events, and limitations in local pipeline and storage infrastructure, rather than by national supply conditions alone.[56] In particular, EIA notes that downstream markets in the Southeast, including the Carolinas, frequently experience price divergence from Henry Hub during periods of high demand or pipeline congestion, even when

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[56] U.S. Energy Information Administration. (2022). *Southeast natural gas markets and winter price behavior*. https://www.eia.gov/todayinenergy/

natural gas prices remain stable.[57] These structural factors help explain why delivered utility gas costs in the Carolinas, as reflected in the figure, do not move one-for-one with Henry Hub and instead incorporate a persistent and time-varying regional premium.

[57] U.S. Energy Information Administration. (2022). *Southeast natural gas markets and winter price behavior*. https://www.eia.gov/todayinenergy/

As shown in *Table 3*, procuring natural gas for electric generation involves an array of entities, contract types and types of costs.

Transaction	Contract Type(s)	Name or Type of Costs	Gas ownership & custody	Regulatory oversight
Duke buys gas from upstream suppliers	• Fixed-price supply • Index-based • Percentage-of-burn	• Delivered gas cost	• Producers & marketers until delivered to Transco	• State regulator (*see Sec VI*)
Duke procures and contracts for interstate pipeline transportation and, where applicable, local distribution service	• Interruptible Transportation • Firm Transportation • Enhanced Firm Transportation	• Transportation • Hedging costs • Transco's FERC tariff	• Duke assumes title at receipt point • Interstate pipeline has custody until plant delivery point or a city gate where an LDC assumes custody	• FERC
Backhaul to ensure Duke's scheduled volumes are fulfilled	• Displacement agreements • Secondary market capacity release • Offsetting shipper transactions		• Duke has title • Transco has custody	• FERC, but no documentation was found
Ensuring delivery under system constraints	• Not contractual • Continuously traded, market-driven spread Financial instruments and derivatives: • Swaps • Futures & Forwards • Options	• Real-time basis premium, varies intraday and daily • Hedging costs		• CFTC (financial derivatives) • State commissions (cost recovery via fuel riders)
If Duke were to receive approval to use third party services to store gas as LNG	• Firm storage • Interruptible storage • LNG liquefaction & regasification services	• Demand (capacity) charges • Injection / Withdrawal fees	• Duke retains title • Storage operator has custody	• FERC • State commissions
Gas transfers to intrastate pipelines or LDCs for delivery to power plants	• Intrastate transportation • Local delivery agreements	• Distribution charges • Final delivery fees	• Duke has title • Custody depends on delivery configuration	• State commissions

Table 3: Types of natural gas contract and costs, with regulatory oversight, for each type of natural gas transaction

VI. Hedging Practices

Duke Energy and its regulated subsidiaries—Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), Duke Energy Indiana (DEI), and Piedmont Natural Gas (PNG)—use financial derivatives to moderate fuel-cost volatility and stabilize retail bills. The stated purpose of hedging, as reported in Duke Energy's filings, is to achieve cost smoothing within regulatory parameters rather than speculative gain. Because these entities operate under fuel-adjustment mechanisms, most derivative gains or losses are deferred into regulatory assets or liabilities rather than recognized immediately in earnings.[58]

A. Financial Instruments and Derivatives

Gas Derivatives

A derivative is a financial contract whose value is derived from an underlying asset, index, or benchmark. The defining feature is that it does not require ownership of the physical commodity; its value moves with changes in the underlying price. When the underlying asset is natural gas—such as Henry Hub or regional hubs like Transco Zone 5 or Eastern Gas South—the contract is considered a gas derivative. Gas derivatives enable utilities, producers, and market participants to manage fuel-price volatility without engaging in physical gas transactions. Common gas derivatives include natural gas swaps, natural gas futures, basis swaps, and options on gas-related contracts. These instruments function as financial hedges that stabilize fuel costs and protect against unexpected market movements.

Swaps

A swap represents an agreement between two parties to exchange future cash flows, typically one fixed and one floating price. Economically, swaps reduce exposure to short-term market shocks but can lead to opportunity losses when market prices fall below the contracted fixed price.

Consider a fixed-price swap in which Duke agrees to pay a fixed price of $3.50/MMBtu for a defined gas volume while receiving the floating market price from its counterparty. If market prices

[58] Form 10-K (2024, pp. 185–187); Form 10-Q (2025, pp. 71–72).

rise to \$5.00/MMBtu, the counterparty pays Duke the \$1.50/MMBtu difference, offsetting Duke's higher physical gas costs. If market prices fall to \$2.50/MMBtu, Duke pays the counterparty \$1.00/MMBtu but simultaneously benefits from purchasing physical gas at the lower market price.

The counterparty—usually a financial institution, a commodity trading firm (e.g., BP, Shell Trading, Macquarie), or a gas marketer—enters the swap because it has its own risk-management strategy, market view, or commercial exposure. These entities may:

- Hold opposite physical or financial positions that need hedging,
- Profit by taking on price risk that Duke seeks to avoid,
- Maintain diversified portfolios where gains in one market offset losses in another, or
- In the case of producers, they benefit when prices move differently from utilities.

This hedging structure converts volatile market exposure into more predictable net costs, thereby stabilizing customer bills over time. However, because price insurance is not cost-free, long-term swap programs could slightly increase average costs in exchange for reduced volatility. Duke relies primarily on fixed-for-floating natural gas swaps—often extending several years into the future—as its core hedging instrument, using them to limit rate spikes even though the program may yield modest net costs in years when market prices fall.[59]

Futures and Forwards

Futures are standardized exchange-traded contracts, while forwards are customized bilateral agreements. Both instruments establish a fixed purchase price for gas to be delivered in the future. Futures provide liquidity and clearinghouse transparency, whereas forwards offer counterparty-specific flexibility. Duke uses these instruments to hedge expected fuel requirements for its generation fleet.[60]

For example, Duke may purchase February 2026 Henry Hub natural gas futures at a fixed price of \$3.20 per MMBtu to hedge expected winter fuel requirements. When February arrives, the futures position settles financially against the actual spot price. If the spot price rises to \$5.00, the futures

[59] Form 10-K (2024, p. 186).
[60] Form 10-K (2024, p. 187).

contract gains \$1.80 per MMBtu—which Duke receives from the counterparty—effectively offsetting the higher physical gas cost paid in the market. If the spot price instead falls below \$3.20, Duke incurs a financial loss on the futures contract but benefits from purchasing cheaper physical gas, keeping overall costs stable.

Hedging can also target regional delivered prices. Duke may secure a forward contract indexed to Transco Zone 5 rather than Henry Hub. For instance, the utility might lock in a delivered price equal to *Henry Hub + \$0.80 basis*, effectively fixing both the commodity portion and the regional basis premium embedded in Zone 5 pricing. This structure protects Duke not only from national gas price volatility but also from spikes in regional basis—particularly important in constrained markets served by Transco Zone 5.

Both approaches—Henry Hub futures and Zone 5 forwards—allow Duke to convert uncertain future gas prices into predictable procurement costs. The trade-off is that the utility gives up potential savings if market prices fall, but in return secures bill stability and insulation from severe winter price shocks.

Options

An option grants the right, but not the obligation, to buy or sell gas at a predetermined price. Duke applies "call" or "put" options selectively to cap upward price risk while retaining potential benefits from falling prices.[61]

For example, Duke may purchase a call option giving it the right (but not the obligation) to buy 1 million MMBtu at a strike price of \$4.00 per MMBtu for December. If the actual market price rises to \$6.00, Duke exercises the option and purchases gas at \$4.00, effectively saving \$2.00 per MMBtu (minus the upfront premium paid for the option). If December prices instead remain at \$3.00, Duke simply lets the option expire and purchases gas at the lower market price, losing only the premium. This asymmetry allows Duke to benefit when prices fall while being protected against severe upward spikes.

[61] Form 10-Q (2025, p. 72).

Utilities may also use put options, which provide the right to *sell* gas at a predetermined price. While this is less common for utilities than calls, put options can still play a role. For instance, suppose Duke purchases a put option allowing it to sell gas at $3.50 per MMBtu during a later month when prices are uncertain. If market prices fall to $2.00, Duke exercises the put and receives the higher $3.50 strike price—effectively protecting the value of gas purchased earlier or gas embedded in a fixed-price contract. If prices instead stay above $3.50, Duke allows the option to expire, losing only the initial premium.

In both cases, options offer one-way protection:

- A call protects against price spikes.
- A put protects against price collapses.

Unlike swaps or futures, which lock in a fixed price and therefore eliminate both upside and downside, options allow Duke to retain favorable price outcomes while still capping extreme risks. This type of asymmetric protection is particularly valuable during periods of elevated volatility, such as winter demand peaks, hurricane-related Gulf Coast disruptions, or sudden pipeline constraints in Transco Zone 5.

Designated vs. Undesignated Hedges

Under Generally Accepted Accounting Principles (GAAP), a designated hedge must meet documentation and effectiveness requirements to qualify for hedge accounting, with changes in fair value recorded through *Other Comprehensive Income* until settlement. Undesignated hedges, although not qualifying for such treatment, are still deferred for recovery through regulatory accounts.[62]

For example, if Duke purchases an undesignated gas swap that generates a $10 million gain, this amount is recorded as a regulatory liability rather than as income, thereby reducing future fuel charges. Much of Duke's portfolio falls under this undesignated category, illustrating the company's regulatory approach to commodity hedging.

[62] Form 10-K (2024, pp. 186–187).

B. Performance of Duke Energy's Electric Fuel-Hedging Programs

Duke Energy's regulated electric utilities employ structured fuel-hedging programs intended to reduce natural-gas price volatility and stabilize retail fuel charges. The performance of these programs varies across Duke's jurisdictions, with North Carolina's Duke Energy Progress (DEP) showing substantial consumer benefits, while Duke Energy Florida (DEF) experienced long-term net costs that led regulators to restrict future hedging. Together, these cases illustrate how hedging outcomes depend not just on market conditions, but on hedge horizon, volatility regime, and regulatory design.

Duke Energy Progress (DEP) Case Study: A Year of Strong Benefits After Earlier Losses

The most detailed and credible assessment of Duke's electric hedging performance comes from the North Carolina Utilities Commission (NCUC) Public Staff, which reviews DEP's natural-gas and coal hedging annually in fuel-cost proceedings. In its 2022 testimony, the Public Staff concluded that the DEP hedging program is reasonable, well-managed, and beneficial to customers, despite mixed performance in prior years.[63] While this section describes the Public Staff's findings, *Figure 8* shows that the 2021-2022 period was an anomaly, being the only years from 2017-2024 where Duke paid lower gas fuel premiums than other Southeast utilities.

During the 2021–2022 test year, hedging produced the largest net benefit in DEP's history.

- Systemwide benefit: approximately $122.7 million
- Benefit to North Carolina customers: approximately $75.5 million
- Residential impact: equivalent to ~$22.82 per 1,000 kWh in annual bill reductions
- Share of total gas costs offset: roughly 13% of a total $948.7 million natural-gas commodity expense

These outcomes resulted from effective short- and medium-term hedges that shielded customers during an exceptional period of price volatility—Henry Hub volatility reached 179% in February

[63] John R. Hinton, *Direct Testimony*, Public Staff – North Carolina Utilities Commission, Docket E-2 Sub 1292 (2022), from https://starw1.ncuc.gov/NCUC/PSC/PSCDocumentDetailsPageNCUC.aspx?DocumentId=6a8f3b64-cf06-4f5d-84f8-b8fd679091f2&Class=Filing

2022—while avoiding the excessive forecast error associated with long-dated futures. The Public Staff emphasized that hedging acted as intended: not to lower long-run average costs, but to prevent rate spikes during volatile market conditions.[64]

Historic results, however, were more mixed. Between 2012 and 2017, DEP incurred significant net hedging costs due to long-term fixed-price positions entered at a time when natural-gas price forecasts were severely inflated. The EIA's Annual Energy Outlook (2008–2013) materially overestimated gas prices for 2012–2017—by as much as 110 percent—leading to hedge prices that exceeded realized spot prices once shale-gas production expanded and prices collapsed. As a result, residential customers saw fuel-charge increases of $25–$27 per year per residential customer in 2013 and 2016, and increases between $10-$12 per year per residential customer in 2014, 2015, and 2017.[65]

The Public Staff attributed these losses not to mismanagement, but to structural forecast error and recommended that Duke avoid long-dated hedge horizons (generally >3 years). With the adoption of shorter-term, rolling hedge structures, recent results show improved alignment with actual market conditions and substantial consumer benefits. But this may be a premature conclusion.

It is unclear why Duke Energy's hedging approach appears to have not worked as well in 2023 and 2024. One indication may be the higher than historical gas premiums Duke paid in 2023 and 2024 (*Figure 7*), raising questions of how the higher premiums are related to Duke's hedging strategy. Data was not available on hedges Duke entered into in 2022 when fuel prices were higher. Further, the addition of 2025 data may help clarify whether Duke's increased volume of gas purchases and generation relative to system constraints in 2023-2025 is exhausting Duke's ability to moderate fuel-cost volatility and stabilize retail bills using financial instruments and derivatives.

Duke Energy Florida (DEF): Long-Term Net Costs and a Hedging Moratorium

In contrast to DEP, Duke Energy Florida's hedging performance over the long term triggered significant regulatory concern. The Florida Public Service Commission (FPSC) conducted multi-

[64] John R. Hinton, *Direct Testimony*, Public Staff – North Carolina Utilities Commission, Docket E-2 Sub 1292 (2022)
[65] John R. Hinton, *Direct Testimony*, Public Staff – North Carolina Utilities Commission, Docket E-2 Sub 1292 (2022)

year reviews of IOU hedging outcomes—including DEF—in Docket 170057-EI, concluding that the statewide hedging portfolio produced large net costs for customers over the 2002–2015 period. The FPSC found that hedging did not consistently reduce volatility and, in many years, increased fuel costs relative to a simple cash-market purchasing strategy.[66]

As a result, Florida adopted a "risk-responsive" hedging framework and ultimately imposed a moratorium on new financial natural-gas hedges for Duke Energy Florida, prohibiting the utility from entering new swap or futures positions until December 31, 2027. Existing hedges continue to run off, but DEF now relies primarily on index-based procurement rather than financial hedging.[67]

DEF therefore serves as a contrasting example: a jurisdiction where long-term hedging produced sustained consumer losses and regulators scaled back the hedging program to protect ratepayers.

C. Restrictions

Hedging at Duke Energy Florida (DEF) is subject to regulatory restrictions following findings by the Florida Public Service Commission (FPSC) that prior fuel-hedging programs produced net customer losses without clear stability benefits. The FPSC's order in Docket No. 20220001-EG prohibits DEF from entering new financial natural gas hedges until December 31, 2027 (Duke Energy, 2024).[68]

This prohibition encompasses swaps, futures, and options intended to fix gas prices for DEF's generation fleet. Existing hedges were permitted to mature naturally, but no new financial positions may be established. Physical supply and transportation contracts remain unaffected.

The moratorium arose from the 2014–2019 hedge review, during which the FPSC determined that DEF's financial hedges cost customers more than spot-market purchases. Although the hedges were deemed prudent under prior approvals, they failed to deliver measurable benefits. As a result,

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[66] Florida Public Service Commission, *Review of Investor-Owned Utility Hedging Practices*, Docket 170057-EI – Staff recommendations and Commission orders (2017–2022)

[67] Florida Public Service Commission, *Review of Investor-Owned Utility Hedging Practices*, Docket 170057-EI – Staff recommendations and Commission orders (2017–2022).

[68] Form 10-K (2024, p. 189); Florida PSC Docket No. 20220001-EG (2022).

DEF now operates primarily through index-based procurement and firm transportation contracts, purchasing gas near the delivery date at Transco or Florida Gas Transmission (FGT) prices.

The FPSC's order carries three primary implications:

1. Regulatory Confidence and Oversight. DEF must demonstrate that its near-term procurement yields reasonable results without speculative exposure.
2. Operational and Financial Effects. Without hedging, DEF remains exposed to short-term price volatility and must rely more on storage and intra-month purchases for flexibility.
3. Benchmark for Other Jurisdictions. The DEF experience serves as a precedent for other state commissions evaluating the prudence and results of hedging programs.

In summary, the Florida restriction illustrates the tension between price stabilization and regulatory accountability. While hedging aims to mitigate volatility, its failure to do so can invite policy pushback. DEF's unhedged, index-based approach through 2027 will serve as a real-world test of whether transparent short-term pricing can outperform structured hedging in a modern gas market.[69]

D. Potential Insufficiencies in Duke Energy's Hedging Approach

Although Duke Energy's hedging program advances the regulatory goal of rate stability, several structural and operational factors limit its overall effectiveness. These constraints fall into five main categories: basis-risk exposure, limited transparency, overreliance on financial instruments, regulatory timing lag, and pipeline concentration.

Exposure to Zone 5 Basis Premiums

A large portion of Duke's natural gas deliveries occur in Transco Zones 4 and 5, where capacity constraints and power-sector demand create persistent price premiums relative to Henry Hub. Duke's swaps and forwards generally reference Henry Hub, leaving unhedged exposure to regional price differentials.[70] For instance, if Henry Hub trades at $3.00 per MMBtu while Zone 5 trades at

[69] Florida Public Service Commission Order PSC-19-0210-FOF-EG (2019).
[70] Form 10-K (2024, p. 186).

$4.20, a Henry-Hub-indexed hedge eliminates commodity volatility but not the $1.20 basis premium.

Limited Hedge Transparency

While Duke discloses total hedge volumes and maturities, it does not detail hedge-to-load ratios, counterparty diversification, or maturity schedules by subsidiary. Many positions are undesignated hedges, which qualify for regulatory deferral but lack full accounting transparency.[71] This opacity restricts external evaluation of hedge effectiveness and leaves ratepayers reliant on annual commission reviews under NCUC Rule R8-55 and PSCSC Fuel Clause proceedings.

Overreliance on Financial Derivatives vs. Physical Hedges

Duke's hedge portfolio relies almost entirely on financial derivatives such as swaps, forwards, and limited options—rather than physical hedges such as fixed-delivery contracts, expanded storage capacity, and fuel or resource diversification. Financial hedges stabilize prices but cannot guarantee physical deliverability during constrained conditions.[72] Events like Winter Storm Elliott (2022) revealed that while Duke's financial positions offset price spikes on paper, actual procurement remained dependent on available pipeline and storage resources.

Regulatory Lag and Timing Mismatches

Fuel-cost recovery through fuel-adjustment clauses often lags behind actual hedge settlements, creating temporary timing mismatches between market outcomes and rate adjustments.[73] Although these mismatches eventually balance out, they can create interim liquidity stress and rate variability during periods of high volatility.

Concentration Risk in Pipeline Access

Duke's gas delivery network is geographically concentrated: DEC and DEP rely on Transco, while DEF depends on Florida Gas Transmission (FGT). This limited pipeline diversity restricts flexibility in sourcing alternatives during disruptions. The company's filings acknowledge that

[71] Form 10-Q (2025, p. 72).
[72] Form 10-K (2024, pp. 185–187).
[73] Form 10-Q (2025, p. 71).

"commodity price exposures remain subject to transmission constraints and locational differentials".[74]

In summary Duke Energy's hedging framework has exhibited the ability to effectively mitigate short-term commodity price swings but leaves residual exposure to basis premiums, delivery constraints, and regulatory timing risks. Consequently, customers may experience elevated delivered-gas prices even in well-hedged years due to structural market limitations.

VII. Duke Energy's Proposed LNG Procurement for Electric Generation versus LNG Storage Owned by Gas-Utility Affiliates

Duke Energy's natural-gas supply strategy spans both its regulated electric-generation fleet and its affiliated natural-gas distribution businesses. These functions rely on different procurement and storage practices, and distinguishing between them is important for understanding fuel sourcing, system reliability, and cost allocation within Duke Energy's regulated operations.

A. Just-in-time Procurement for Power Plants

Duke Energy procures natural gas and fuel oil for its Electric Utilities and Infrastructure (EUI) generation fleet under standard industry agreements with multiple suppliers, apparently including its affiliate Piedmont Natural Gas where applicable.[75] These contracts typically cover a portion of forecasted fuel burns over rolling time horizons and carry staggered expiration dates, creating a flexible portfolio aligned with changing market and demand conditions.

Operationally, Duke Energy Carolinas does not maintain physical natural gas inventories for electric generation. Instead, it follows a "just-in-time" procurement model in which gas is purchased and consumed in real time to match daily generation requirements. This practice differs from traditional coal or diesel fuel stockpiling – which Duke also currently employs at the site of

[74] Form 10-K (2024, p. 186).
[75] Duke Energy Carolinas, LLC. NCUC Form E-1 Data Request, Docket No. E-7 Sub 1214.

dual-fuel units – and highlights the company's reliance on continuous coordination with pipelines and suppliers to sustain uninterrupted operations.

To underpin these short-term purchases, Duke Energy holds a diversified portfolio of long-term transportation and capacity contracts that guarantee pipeline access and delivery reliability under most conditions. In general, pipeline and storage-capacity agreements extend as long as 19–20 years with options to renew, while commodity-supply contracts generally range from two to four years, with some extending up to seven years.[76] Specifically, Duke Energy Carolinas and Duke Energy Progress have contracted substantial interstate firm-transportation rights of about 1,000,000 MMBtu/day on Transco's Southeast Supply Enhancement (SSE) project, 250,000 MMBtu/day on Mountain Valley Pipeline's Southgate project, and 275,000 MMBtu/day to be enabled by the Mountain Valley Pipeline Boost project which is intended to bolster deliverability to southeastern generation assets.[77] FERC approved[78] the SSE project on January 29, 2026 and the target in-service date is 2027.[79] FERC issued an amended Certificate of Public Convenience and Necessity for the MVP Southgate project in December of 2025, with a target in-service date in 2028.[80]

Complementing these logistical arrangements, Duke Energy subsidiaries, including DEC, DEP, DEF, and DEI employ derivative instruments such as swaps to mitigate exposure to natural-gas price volatility. These programs operate under a structured execution plan extending up to five years, with hedge volumes increasing as delivery dates approach. This layered hedging schedule stabilizes customer fuel costs while insulating a portion of operations from sharp market fluctuations.

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[76] Duke Energy Progress. (2023). *Annual Report*.
[77] East Daley Analytics. *The Burner Tip: Weekly Natural Gas Insights*. https://eastdaley.com/the-burner-tip/mvp-expansion-gets-a-boost; and Duke Energy. Verified Petition for Approval of 2025-2026 CPIRP, Appendix I at 2.
[78] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260129-3076&optimized=false&sid=67c71a1c-e2cb-4f1e-928d-ebba1d600126
[79] Duke Energy. Verified Petition for Approval of 2025-2026 CPIRP, Appendix I at 3.
[80] MVP Southgate. *Project Updates*, from https://www.mvpsouthgate.com/project-updates

B. LNG Storage Assets Owned by Duke's Gas-Utility Affiliates

Separate from electric-generation fuel procurement, Duke's affiliated gas-utility businesses—primarily Piedmont Natural Gas—own interests in several LNG and underground storage facilities[81], including:

- Pine Needle LNG facility (North Carolina)
- Hardy Storage facility (West Virginia)
- Robeson LNG facility (North Carolina)

These facilities primarily serve **natural-gas distribution and pipeline-balancing functions**, including peak-shaving during winter heating demand, system-reliability support for gas customers, and management of pipeline constraints.

For example, Piedmont Natural Gas's interest in Pine Needle LNG and Hardy Storage is disclosed in Duke Energy's annual filings as part of the company's gas-distribution infrastructure portfolio, and the Robeson LNG facility was constructed to support Piedmont's gas-distribution system reliability and peak-shaving capability.[82]

While gas withdrawn from these facilities may ultimately flow through the interstate pipeline network also supplying electric generators, the storage assets themselves are to date planned and operated as part of Duke's regulated natural-gas utility system rather than as dedicated fuel inventories for electric-generation units.

Clarifying this distinction is important because storage facilities supporting gas-distribution load are subject to different planning assumptions, operational requirements, and cost-recovery mechanisms than facilities dedicated to electric-generation fuel supply. And this information should not be confused or considered representative of the DEC and DEP proposal to build, own, and operate new LNG facilities for electric service that is currently pending before regulators.

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[81] Duke Energy Corporation, *Form 10-K for the fiscal year ended December 31, 2024*, pp. **4–6**, "Business Segments," describing Duke's regulated Electric Utilities and Infrastructure segment and Natural Gas Distribution segment as separate regulated businesses.
[82] [82] Duke Energy Corporation, *Form 10-K for the fiscal year ended December 31, 2024*, pp. **4–6**

C. Long-Term LNG Storage Strategies

Beyond day-to-day procurement, Duke Energy's long-term proposed electricity strategy is to introduce liquefied natural gas (LNG) storage as both a physical hedge against supply disruptions and as an option to complement naturally variable renewable generation. Duke Energy Progress and Duke Energy Carolinas incorporated LNG storage modeling into the Companies' 2025 Carbon Plan Integrated Resource Plan (CPIRP) to partially evaluate system-wide reliability requirements.[83] Under this framework, combined-cycle units CC4 through CC6 are proposed to allocate proportional LNG infrastructure costs as part of Duke's broader fuel-security portfolio.

Existing assets already demonstrate the significance of LNG in Duke's supply architecture. Duke subsidiary Piedmont Natural Gas owns a 45 percent interest in the Pine Needle LNG storage facility in North Carolina and a 50 percent interest in the Hardy Storage facility in West Virginia. In addition, Duke invested approximately $250 million to develop the Robeson LNG facility, initiated in 2019 and placed in service in 2021.[84] Collectively, these assets expand PNG's capacity to liquefy, store, and vaporize gas during periods of pipeline constraint or extreme weather stress.

Strategically, Duke Energy annual reports and proposed plans collectively view LNG storage as a component of long-term fuel-reliability planning. Duke Energy's short-term fuel procurement strategy emphasizes flexibility, real-time acquisition, and price stabilization through hedging, while its LNG storage strategy embodies a long-term investment in gas fleet expansion that is currently contingent upon the approval and placement into service of three separate pipeline projects, on a timeline and capacity that will presumably not compromise fossil fuel supply resilience and fuel security. The 2025 CPIRP natural gas fleet modernization strategy focuses on fuel diversification, given current limitations on diesel fuel supply and planned coal retirements, but less so on broader resource diversification, meeting system balancing requirements at least cost, and planning considerations that may include economic non-fuel resource, load flexibility,

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[83] Duke Energy. Verified Petition for Approval of 2025-2026 CPIRP, Appendix I; and North Carolina Utilities Commission (N.C.U.C.). Docket No. E-2, Sub 1358, *Direct Testimony of Albert Lin on Behalf of the North Carolina Sustainable Energy Association*.

[84] Piedmont Natural Gas (a subsidiary of Duke Energy Corporation), *"Piedmont Natural Gas to Build New Liquefied Natural Gas Facility in North Carolina,"* Duke Energy News Center press release, July 13, 2018, available at: https://news.duke-energy.com/releases/piedmont-natural-gas-to-build-new-liquefied-natural-gas-facility-in-north-carolina. The release states that the Robeson LNG project was estimated to cost approximately $250 million, with construction expected to begin in summer 2019 and completion anticipated in summer 2021, and describes the facility as supporting system reliability during peak-demand periods.

and transmission system alternatives to its proposed introduction of ELNG.[85] In the near term, however, Duke prioritizes completion of interstate pipeline expansions, particularly Transco's SSE and MVP Southgate projects as the most immediate means of enhancing firm transportation capacity and mitigating regional fuel supply bottlenecks.[86]

To ensure the most economic options can be selected from the full range of available resource options, it is important to accurately define and use terminology that describes the basis for proposed introduction of new fuel-related assets on the system. Specifically, DEC and DEP pending plans note that LNG storage assets need to be introduced to provide 'back up capacity' as greater shares of naturally variable renewable generation enter the grid. Renewable energy is forecastable within boundary conditions (e.g., excess wind shut offs and cloud cover) and, similar to fossil and nuclear resources on the system, contribute to and also require complementary measures to maintain system balance. System balancing, not back up capacity for a single type of resource, is required by NERC to maintain adequate contingency reserves for the entire system and control frequency excursions. As noted previously in this paper, the increasing presence of renewables and battery storage capacity (in combination and as stand-alone resources) on the ERCOT system has contributed to maintaining system balance by serving a growing portion of peak demand at a declining cost per MWh.[87]

VIII. Suggested Regulatory Questions

This section outlines targeted areas of inquiry that could guide state regulators and consumer advocates in examining Duke Energy's natural gas procurement and hedging practices. The purpose of these questions is not adversarial; rather, it is to identify information gaps that, once addressed, can enhance transparency, accountability, and alignment between Duke's current and proposed fuel management strategies and ratepayer interests, informed by clear and complete economic information and analysis.

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[85] Duke Energy. Verified Petition for Approval of 2025-2026 CPIRP.
[86] North Carolina Utilities Commission (N.C.U.C.). Docket No. E-2, Sub 1358, *Direct Testimony of Albert Lin on Behalf of the North Carolina Sustainable Energy Association*.
[87] Scott Madden. *Topic 5: Grid Flexibility*. https://publications.scottmadden.com/energy-industry-update-v25-i1/grid-flexibility

Gas Loads and Trends

Additional information is needed to clearly define how Duke Energy's regulated utilities use natural gas across customer classes and end uses. Duke should identify gas consumption by residential, commercial, industrial, and electric-generation customers, including how these shares have evolved over time and how they differ across jurisdictions. Within the electric sector, Duke should further disaggregate gas use by baseload, intermediate, and peaking generation, as well as by seasonal and weather-driven demand patterns.

Historical data spanning at least the past two decades would help illuminate structural trends in gas demand, including the effects of fuel switching, electrification, energy efficiency, and changes in generation dispatch. Such information would clarify whether Duke's gas or electric system, or both, are becoming more dependent on gas during peak conditions and whether that dependence is concentrated in loads that are inherently inflexible, such as residential heating using natural gas, versus loads that may offer some degree of price or operational responsiveness.

Additional information is also needed on demand-side flexibility during extreme weather events or supply disruptions. Duke should be asked to describe the extent to which commercial and industrial loads are interruptible or otherwise responsive under exigent circumstances, how these capabilities are incorporated into gas procurement and transportation planning, and whether demand-side measures could reduce the need to procure high-cost gas during price spikes or outages. Identifying where demand-side flexibility could substitute for incremental supply-side commitments would materially inform the assessment of Duke's gas risk exposure and long-term cost management strategy.

Procurement Practices

Duke could identify its top natural gas suppliers by total contracted volume and by contract type distinguishing between fixed-price and index-based purchases. Additional data on the pricing mechanisms, escalation clauses, and expiration dates of Duke's major supply agreements would illuminate how the company balances price stability against market responsiveness. This disclosure would also clarify whether Duke's procurement strategy is diversified across suppliers or concentrated among a limited group of marketers.

Transportation and Storage

Additional information is needed from unredacted firm transportation agreements, detailing pipeline routes, maximum daily quantities (MDQ), negotiated rates, delivery pressures, and contract expiration dates and renewal clauses. Mapping these data against FERC's Index of Customers filings would inform the degree of Duke's dependence on Transco Zone 5 and other constrained corridors and if these constraints are being effectively addressed over time. Duke should be asked to describe how the negotiated rates with pipeline companies were developed – what factors went into the determination of what Duke agrees to pay for these long-term contracts, understanding that the cost is currently passed through to ratepayers and fuel cost risks are not shared in part by Duke or its shareholders.

Given that firm transportation is essentially a long-term fixed asset, the net present value of the annual payments should be developed for informational comparison to the cost of other new or potential capital assets. Additional necessary information for accurate economic analysis would include Duke Energy's cost and usage data for interruptible transportation services and total contracted storage capacity, including associated fixed and variable charges, how Duke allocates firm transportation costs among customer classes and the dockets in which these allocations are reviewed, the analyses that have been pursued in those dockets and their outcomes, and what is Duke's participation in the firm capacity release market (which would show whether Duke Energy actively manages unused pipeline rights or allows capacity to remain idle).

Hedging Strategy

Duke's filings show extensive use of financial derivatives including swaps, futures, and options, but provide limited detail on the structure and timing of these positions. A high level description of proportional use or an inventory of current hedge positions by instrument type, maturity, and volume could provide visibility to the effectiveness and limits of current hedging practices. A regulatory history behind the Florida Public Service Commission's moratorium on new financial hedging by Duke Energy Florida through 2027 that includes lessons learned and applicability to the Carolinas could identify additional improvements to Duke Energy's hedging strategy.

Finally, Duke should clarify how hedge gains or losses are allocated under current fuel-cost riders and whether any timing mismatches occur between hedge settlement and recovery from ratepayers.

Basis Risk and Market Exposure

Given Duke's geographic concentration in Transco Zone 5, more information is needed including the quantification of Duke's historical basis exposure, the differential between Zone 5 prices and the Henry Hub benchmark over the past five or more years, what non-financial mitigation measures Duke employs, such as capacity swaps, alternative receipt points, or local storage withdrawals, and how frequently these tools are used. Such disclosures would clarify whether customers are paying a persistent cost premium tied to locational concentration rather than commodity fundamentals. This would also better inform the basis premium that should be included in integrated resource planning. Specifically because Duke is proposing expanding its natural gas fleet. It appears natural gas procurement from new gas pipeline capacity projects to fuel the proposed expansion of the gas fleet would be additional to, and not a substitute for, the volume of gas delivered to Duke through Transco Zones 4 and 5. While fuel delivered through new pipeline projects may reduce the average $/MMBtu price, the fuel cost for this new fuel supply, if entirely additional, may not reduce total basis premiums paid by Duke.

Procurement Transparency

Regulators could inquire how Duke benchmarks its natural gas purchase prices against those of peer utilities in the Southeast. Specific comparisons to Southern Company Gas or Dominion Energy would highlight procurement competitiveness. Follow-up questions might explore what internal controls and procurement protocols Duke uses to ensure that all fuel purchases are competitively priced and demonstrably least cost for customers.

Pipeline Dependence and Reliability

Given Duke's significant reliance on Transco Zone 5, regulators might ask the company to quantify the extent of its capacity concentration and to assess associated reliability risks or cost vulnerabilities. Additional questions could probe Duke's contingency planning if key capacity projects to fuel DEC and DEP's natural gas fleet expansion—such as the Transco Southeast Supply Enhancement (SSE), Mountain Valley Pipeline (MVP) Southgate or Gulf Coast expansions—are delayed or canceled, and how such outcomes would affect system reliability and price exposure.

Storage Utilization

Regulators could request detailed usage data for PNG's LNG and underground storage assets, including Pine Needle LNG and Hardy Storage. Questions might cover annual cycle frequency, injection and withdrawal patterns, and cost-benefit justification for maintaining these facilities.

Further inquiry could clarify how storage costs—both fixed and variable—are allocated between base rates and fuel-cost riders, and whether any portion of those assets earns a regulated return on equity. Further, questions could inform cost-of-service regulation by inquiring how, if capital were expended to operationally introduce such facilities into the electricity system, how the total addition of these costs compares to other infrastructure or resource diversification options. These questions help evaluate whether natural gas fuel storage assets deliver tangible reliability benefits commensurate with their costs and may surface or inform accurate assessment of other economic options beyond a narrow band of oil, coal and gas fuel security options, broadening to a set of solutions for economic analysis and comparison that may provide system balance.

Hedging

Regulators could require Duke Energy to explain its internal governance framework for distinguishing legitimate risk-management hedges from speculative trading activities**.** They might also request a detailed list of the information Duke classifies as non-disclosable in relation to undesignated derivative contracts**,** accompanied by the specific legal or regulatory basis for withholding such details. Together, these inquiries would enhance transparency and accountability**,** ensuring that all hedging results are accurately and comprehensively reflected in the regulatory record.

Cost Recovery and Prudence

Consumer advocates may call on Duke Energy to demonstrate how it verifies that all fuel costs recovered through rate riders originate from prudent and cost-effective procurement decisions**.** Regulators, in turn, could require Duke to specify the performance metrics it uses to assess procurement efficiency—such as comparative cost benchmarks, bid competitiveness, or results from internal and external audits. Establishing such metrics would create a consistent, evidence-based framework for evaluating prudence and ensuring that cost recovery remains aligned with ratepayer protection and the public interest**.** This level of scrutiny may be important as natural gas approaches 50% of DEC and DEP energy mix by fuel type in the utilities' preferred plan *(Figure 2)* and may be equally important for evaluating the prudency of long-term fuel contracts as the preferred use of natural gas in Duke's energy mix by fuel type is planned to steadily decline thereafter.

More broadly, the proposed discovery and oversight questions seek to close key transparency gaps in Duke Energy's natural gas procurement and hedging practices. Implementing a structured disclosure process that addresses supplier concentration, transportation dependencies, hedge structures, and basis risk—would enhance regulatory scrutiny, strengthen consumer trust, ensure resource planning is inclusive of fuel costs, and ensure that ratepayers benefit from efficient, transparent, and risk-aware fuel management across all of Duke's service territories.

IX. Conclusion

This paper provides a comprehensive analysis of Duke Energy's natural gas procurement, transportation, storage, and hedging practices, tracing the full chain of custody from production basins to power plant delivery. Using verifiable evidence from SEC filings (Form 10-K and Form 10-Q), FERC Index of Customers (IOC) data, and EIA Form 923 fuel-cost reports, the study reconstructs how natural gas and related costs move through Duke's system and how those flows translate into customer rates under regulatory oversight.

The findings reveal a system designed for stability rather than price minimization. Duke Energy's procurement framework combines long-term firm transportation contracts with diversified supply agreements to ensure deliverability in constrained markets such as Transco Zone 5. This structure reduces operational risk but embeds persistent cost premiums relative to benchmark prices like Henry Hub. Similarly, Duke's hedging programs—composed primarily of swaps and forwards—moderate some volatility in customer bills but cannot eliminate structural price differentials tied to geography and pipeline capacity.

Long-term planning efforts propose introducing liquefied natural gas (LNG) storage as part of Duke's resilience strategy for DEC and DEP. Duke reports that investments in the Pine Needle, Hardy Storage, and Robeson LNG facilities provide physical flexibility to complement financial risk management for PNG. At the same time, Duke's reliance on just-in-time gas procurement for daily operations underscores its dependence on continuous pipeline access—an area that remains vulnerable to capacity constraints and regional congestion.

The evaluation of Duke Energy Florida's hedging moratorium further illustrates how regulatory outcomes evolve when hedging programs underperform or lose credibility. That case reinforces the importance of evidence-based reviews of hedge performance and transparency regarding derivative volumes, maturities, and results.

Finally, the paper identifies observations and questions that regulators and consumer advocates can ask to develop a transparent and accurate understanding of the economic costs, risks, and options. These questions—focused on supplier concentration, pipeline dependence, basis exposure, storage utilization and enabling comparative economic analysis of resources—offer a practical roadmap for improving accountability and ensuring that ratepayers benefit from efficient fuel procurement.

In summary, Duke Energy's natural gas system reflects a deliberate balancing between operational reliability, financial neutrality, and regulatory compliance. The company's layered contracting, hedging, and storage arrangements provide stability under volatile market conditions but also lock in structural costs that require continuous scrutiny and remain above industry peers. Effective oversight—anchored in transparent data, periodic performance reviews, and forward-looking policy evaluation—will remain essential to align Duke's procurement strategy with evolving energy-market dynamics, system constraints, and public interest objectives.

Through this research, a clearer picture emerges: Duke's fuel-cost outcomes are not accidental but the product of regulated design choices. Understanding how those choices interact—across contracts, pipelines, resources, markets, and commissions—is key to evaluating both the fairness and the efficiency of natural gas planning, broader resource planning, and cost recovery in the Carolinas and beyond.

APPENDIX

Duke Energy's firm transportation agreements, including contract numbers, MDQ levels, receipt and delivery points, and expiration dates.[88]

Table A.1: Duke Energy Firm Transportation and Storage Contracts on Transco

Subsidiary	Contract No.	Volumes (Dth/day)	Receipt Point(s)	Zone (Receipt)	Delivery Point(s)	Zone (Delivery)	Contract Term / Expiration
DEF	9097513	153,500	Sta 85 Pool	Zone 4A	Coden-GS M4596	Florida	Expires 2025
DEF	9109950	50,000	Sta 85 Pool	Zone 4A	Coden-GS M4596	Florida	Expires 2026
DEF	9111070	53,500	Sta 85 Pool	Zone 4A	Coden-GS M4596	Florida	Expires 2026
DEP	1042064	75,000	Sta 85 Pool	Zone 4	Cardinal	Zone 5	Expires 2027
DEP	9109923	115,000	Sta 85 Pool	Zone 4	Piedmont	Zone 5	Expires 2031
DEP	9128023	93,000	Sta 85 Pool	Zone 4	Duke Energy Carolina	Zone 5	Expires 2032
DEC	9109922	60,000	Sta 85 Pool	Zone 4	DEC, Piedmont	Zone 5	2011–2031
DEC	9279212	13,000	Sta 165 Pool	Zone 5	Blacksburg	Zone 5	2024–2046
DEC	9293655	4,251,250	Washington Storage	N/A	Washington Storage	N/A	2025–2028
DEC (Expired)	9139583	16,560	Sta 85 Pool	Zone 4	Cherokee Cogen	Zone 5	2013–2017
DEC (Expired)	9172961	75,000	Sta 30;45;50/62/65	Zones 1–3	Piedmont; Washington Storage	Zone 5/Storage	2016–2023

[88] IOC filings from 2024 list Duke's contract portfolio across its subsidiaries—DEF, DEP, and DEC—with expirations from 2025 to 2046.

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