



Gas pipeline companies have set their sights on the Southeast as a profits smorgasbord.

Who will ultimately pay the price?

SOUTHEAST ELECTRIC BILLS ARE PAYING FOR A HIGHWAY TO EXPORT GAS

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Table of Contents

Executive Summary	1
Proposed New Pipeline Projects in the Southeast.....	2
Operational Luxuries.....	3
LNG Exports	6
Making the Connections to LNG facilities	8
LNG Export Profits	9
Paying to Widen the Highway.....	9
Nature Abhors a Vacuum.....	10
Opening Marcellus and Utica to the Southeast.....	11
Gas Pipeline Companies Can't Lose	12



Executive Summary

Gas pipeline companies are expanding pipelines across the Southeast to serve electric utilities' plans to build an unsustainable amount of new gas capacity. **But are electric utility customers paying for infrastructure that ultimately serves to increase gas pipeline companies' ability to export gas to foreign countries, thus increasing gas prices and electric bills?**

To answer this question, we need to think about what happens to the gas molecules in those pipelines when domestic demand is less than the immense quantity of gas supplied, such as in spring and fall, and increasingly as we transition to solar, short and long duration battery storage, onshore and offshore wind, and enhanced geothermal.

Those gas molecules have a pathway of connected pipelines throughout the Southeast, **sort of like a highway**, leading right to Gulf of Mexico and East Coast liquified natural gas (LNG) ports. Utilities contract with the pipeline companies for guaranteed access to these molecules (called "firm transportation"¹), and electric customers (like all of us) pay for these expensive contracts through our utility rates², regardless of whether those contracts and the pipeline projects are actually serving us. *And they will serve us less and less as we decarbonize.* While the utilities that overbuild gas plants may be left with stranded assets (we pay for those too), the pipeline companies also overbuild gas transmission infrastructure and cannot lose. They get paid by our electric bills (through those firm transportation contracts) and then by foreign countries through their affiliate LNG export companies - sometimes for the same molecules.³ Actually, they get paid a lot more by foreign countries than by domestic customers.

- Electric utilities pay for pipeline companies to expand gas infrastructure in the Southeast through firm contracts
- Utilities pass the cost of firm contracts and new pipeline infrastructure on the captive ratepayers
- Pipeline companies can make big profits using that infrastructure to serve other customers, including exporting the gas
- Electric utilities can make big profits for building new gas power plants

Electric
bills go
up

¹ "Firm transportation" is a contracted guaranteed amount of gas per day that a utility is able to access from a pipeline system. This is different from non-firm contracts and interruptible contracts, which are less expensive but also do not guarantee access to pipeline capacity. These contracts are confidential, and we cannot see if they also include "take or pay" clauses that obligate utilities and their customers to pay for a set minimum volume of molecules regardless of whether they are used.

² In North Carolina, for example, the cost of the firm transportation contract with Duke Energy is recovered through Duke's fuel rider.

³ If a firm transportation contract has a minimum purchase requirement, and that minimum volume of molecules is not used, ratepayers have paid the pipeline companies for the molecules once before they are sold on the third-party market where they can wind up being sold again as LNG export.

Proposed New Pipeline Projects in the Southeast

Five significant proposed pipeline capacity expansion projects threaten to negatively impact the Southeast, and all of them are regulated by the Federal Energy and Regulatory Commission (FERC).⁴

- 1 Williams Transco Southeast Supply Expansion Project (1,596,900 dth/day and about 50 miles of 42 inch pipes looped along their existing pipelines)
- 2 Williams Transco Alabama Georgia Connector Project (63,800 dth/day and modifications to five compressor stations)
- 3 EQT Mountain Valley Pipeline Southgate (550,000 dth/day and 30 miles of 30 inch pipe)
- 4 Kinder Morgan/SONAT Southeast Supply Enhancement 4 (1.3 million dth/day and 279 miles of large diameter looping pipelines beside their existing pipelines)
- 5 Kinder Morgan/Tennessee Gas Pipeline Mississippi Crossing (1.5 million dth/d and 206 miles of 36 and 42 inch pipe)

These are in addition to two smaller expansions that recently came online, the Transco Southside Reliability Enhancement Project (423,400 dth/day)⁵ and the Transco Market Link (78,000 dth/day). All of the Southside Reliability Enhancement Project gas goes to Piedmont Natural Gas (a subsidiary of Duke Energy) and 13,000 dth/day of Market Link goes to Duke Energy.

This equates to **5,512,100 dekatherms per day of new gas** contracted to Duke Energy, Dominion Energy, Santee Cooper, Southern Company (Georgia Power, Alabama Power), and some smaller gas distribution utilities. This amount of gas burned per day would result in downstream (power plant) emissions of 106,450,425 metric tons per year of CO₂e. This is the **equivalent of one-sixth of the CO₂ emissions for the entire US gas fleet in 2022.**⁶

But what can be powered with this many dekatherms of energy? How can we

visualize this much energy? Duke estimates that its new, *efficient* combined cycle plants will

⁴ Explore gas pipeline infrastructure on the EIA US Energy Atlas: <https://atlas.eia.gov/apps/3652f0f1860d45beb0fed27dc8a6fc8d/explore>

⁵ One of the ways this issue has flown under the radar is a lack of understanding of key terms and conversions. The industry uses the terms million/billion cubic feet per day, dekatherms per day, and MMBtus (million metric British thermal units). I will be consistently be using the term “dekatherms per day” or “dth/day” but the conversions are:

1 dekatherm = 1 MMBtu

1 billion cubic feet (Bcf) of gas provides 1 million dekatherms of energy

⁶ Source: US EPA Greenhouse Gas Equivalent Calculator: <https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator#results>

require 173 dth/day per MW peak burn (full blast).⁷ Applying this figure, 5,512,100 dth/day could power 31,862 MW of combined cycle power plants running full blast all at one time, all day, every day.

That is a lot of megawatts. If these molecules were all directed to power plants, how many plants could this amount of gas fuel? Duke's planned new Roxboro combined cycle plants are a massive 1,360 MW each.

So this new gas, just for North Carolina, South Carolina, Georgia, and Alabama, is enough to build another 23 Roxboro combined cycle units and run them full blast 24/7.

For additional size context, Duke's current existing fossil fuel fleet (24 coal and gas plants) has a total capacity of 21,269 MW.⁸ So the amount of new gas contracted into the Southeast is like **dropping the equivalent of 1.5 times Duke Energy's current fossil fleet into just four states** in a very short timeframe.

Much of the forecasted increased load growth that utilities are using to justify new gas plants (and new gas contracts) is based on estimated, largely unsubstantiated demand from data centers.⁹ These estimates for data centers in the Southeast, especially those that specialize in large language model artificial intelligence, are still largely speculative at this point. Many tech companies have sustainability goals that would preclude the use of fossil fuels for operations. And data center siting is not simple. Owners and developers face significant challenges, including access to transmission, GPU and related equipment supply chain delays, water access issues, and increasing local land use opposition.

Operational Luxuries

Of the over 5 million dth/day explained above, Duke Energy, which operates in North Carolina and South Carolina, has contracted for 1,263,000 dth/day.¹⁰ In their most recent Carbon Plan Integrated Resource Plan (CPIRP) filing, Duke made the case that they require all of this firm transportation in order to have full capacity coverage of their entire existing and proposed gas combined cycle fleet. The NC Utilities Commission encouraged this, and the Public Staff agreed.

⁷ In the Carbon Plan docket, Duke calculated that it needs 705,000 dth/day for three new 1,360 MW combined cycle plants. See Table 1.

⁸ Source: Duke Energy Carbon Plan Integrated Resource Plan Appendix B <https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/appendix-b-dec-and-dep-system-information.pdf?rev=33c1e1fb41324568b367786b9b4813b4> p. 2

⁹ Institute for Energy Economics and Financial Analysis: Data Centers Drive Buildout of Gas Power Plants and Pipelines in the Southeast <https://ieefa.org/sites/default/files/2025-01/UPDATED-REVIEWED-Southeast%20Gas%20Infrastructure%20and%20Data%20Cente.pdf> January 2025

¹⁰ 1,000,000 from Transco Southeast Supply Enhancement, 250,000 from MVP Southgate, and 13,000 from Transco Market Link

Duke witnesses stated during the CPIRP hearing that, if this firm transportation gas is not needed on any given day, they can use it in their CT (peaker) fleet.¹¹ But later in the same testimony, a Duke witness stated that having firm transportation for all of their gas (CCs plus CTs) is “an **expensive operational luxury that’s really just not necessary.**”¹² (emphasis added)

Firm transportation gas contracts are much more expensive than non-firm and interruptible gas contracts and buying on the third-party or “spot” market, and they are usually for 20 years. So a utility (and its ratepayers) are locked in to this confidential fixed reservation fee for 20 years - even if the utility uses less and less of the gas during that time.

“Firm service contracts generally require the customer to pay a firm reservation fee, which is a fixed, monthly charge to reserve an agreed upon amount of pipeline or storage capacity **regardless of whether the customer uses the capacity.**”¹³ -EQT 2024 10-Q (emphasis added)

In the Duke Energy CPIRP proceeding last fall, Duke Energy also cited the significant expense of firm transportation gas as a reason not to convert its 2,200 MW Belews Creek coal plant to run on 100% fossil gas.

"Firming up such a large quantity of gas would be expensive (approximately \$5 billion) for the Companies' customers."¹⁴ -Verderame, Donochod, and Hoeflich, Witnesses for Duke Energy in the 2024 Carbon Plan IRP (emphasis added)

So **\$5 billion to firm up gas for 2,200 MW** - this gives us a sense of just how expensive these contracts are.¹⁵ But despite the cost, Duke Energy has purchased or is in the process of purchasing firm transportation contracts for its entire combined cycle gas fleet, as shown below in their CPIRP filings:

¹¹ Source: CPIRP August 5, 2024 Hearing Transcript Vol. 23 (NCUC Docket No. E 100 Sub 190) <https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=88582c03-b4c0-4f0a-af46-5828f09ea728> at p. 31

¹² Source: CPIRP August 5, 2024 Hearing Transcript Vol. 23: (NCUC Docket No. E 100 Sub 190) <https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=88582c03-b4c0-4f0a-af46-5828f09ea728> at p. 69

¹³ Source: EQT September 30, 2024 Form 10-Q: <https://d18rn0p25nwr6d.cloudfront.net/CIK-0000033213/fab55e46-67c2-4bf2-906e-e01ecc5b3a2c.pdf>

¹⁴ Source: CPIRP August 2, 2024 hearing transcript Vol. 22 (NCUC Docket No. E 100 Sub 190): <https://starw1.ncuc.gov/NCUC/page/docket-docs/PSC/DocketDetails.aspx?DocketId=7409648d-c9c2-4f42-8709-a0830971812d> at p. 281

¹⁵ The Belews Creek site already has access to gas and is located near the Transco mainline, so this \$5 billion likely does not include costs for pipeline construction.

Table 1: DEC and DEP – Interstate FT CC Requirements

[BEGIN CONFIDENTIAL]

Company	Combined Cycle Generation	Approximate Max Demand (MMBtu/Day)
DEC	Buck CC	[REDACTED]
DEC	Dan River CC	
DEC	WS Lee CC	
DEP	Asheville CC	
DEP	HF Lee CC	
DEP	Richmond Co CCs	
DEP	Sutton CC	
Existing CCs Demand Total		980,000
DEP	Proposed CC 1	[REDACTED]
DEP	Proposed CC 2	
DEC	Proposed CC 3	
Proposed CCs 1-3 Demand Total		705,000
Forecasted Interstate FT Requirements		1,685,000

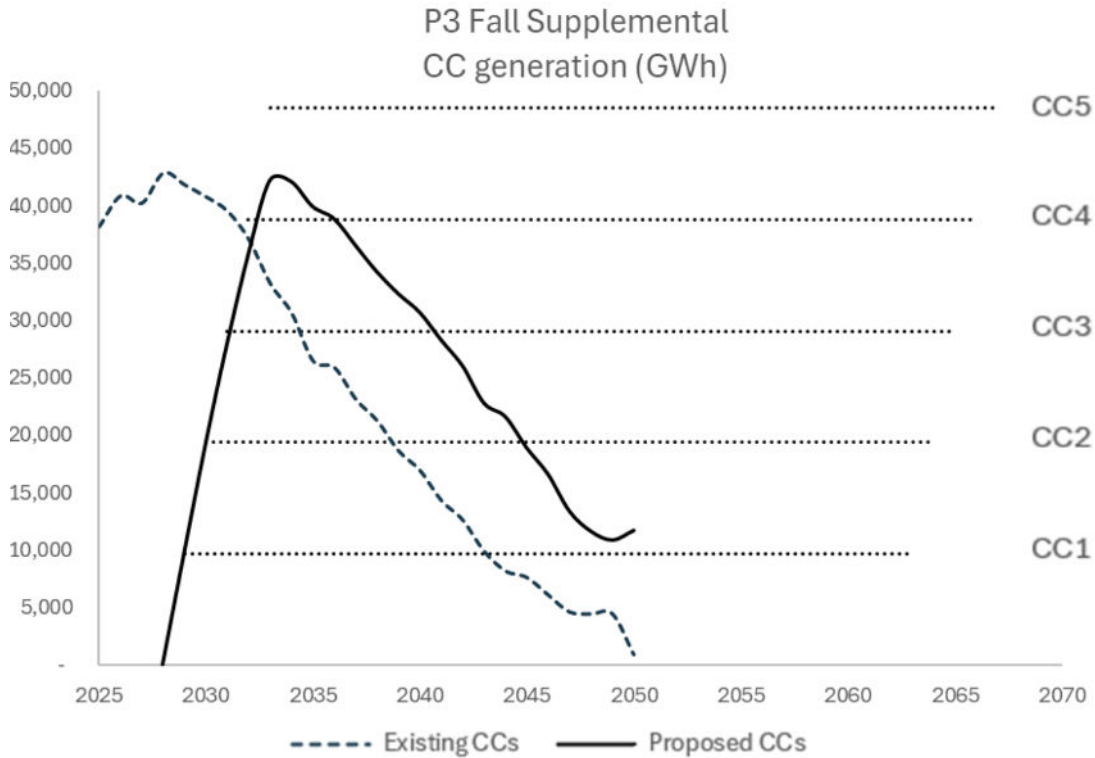
[END CONFIDENTIAL]

Table 2: DEC and DEP – Interstate FT Rights

Pipeline	FT Rate / Expansion	Physical Gas Supply Source	FT Rights (MMBtu/Day)
Transco	85 North	Gulf Coast	175,000
Transco	Mid-South	Gulf Coast	93,000
Transco	Rate Schedule FT	Gulf Coast	75,000
Transco	Sundance	Gulf Coast	75,000
Transco	Sunbelt	Gulf Coast	16,560
Transco	Carolinas Market Link	MVP/Station 165	13,000
Existing Interstate FT Total			447,560
Transco	Southeast Supply Enhancement	MVP/Station 165	1,000,000
MVP	Southgate	MVP/Station 165	250,000
Contracted Interstate FT Total			1,250,000
Forecasted Interstate FT Rights			1,697,560

Source: CPIRP Testimony [Volume 23](#) p. 30 in NCUC Docket No. E100 Sub 190

But the fleet rarely operates at full burn. On all except for a handful of days - or perhaps only for a few hours - **Duke customers will be paying a monthly premium for more gas than is needed for the combined cycle fleet.** Duke’s ratepayers will pay for this unneeded luxury. And over time, well before the new 20-year contracts expire, Duke projected that both the proposed new *and* the existing combined cycle plants will run dramatically less as renewables and energy storage come online. The decline in combined cycle operations is shown below:



Source: CPIRP [Direct Testimony of Maria Roumpani](#), p. 49 in NCUC Docket No. E100 Sub 190

The dropoff for the new combined cycle plants starts as early as 2035 - a mere ten years from now - leaving plenty of ratepayer cost obligation left in those 20-year contracts. The dropoff for the *existing* fleet starts even sooner. **And Duke customers will still pay a premium for gas they don't use.**

So, what happens when Duke, Dominion, and Southern Company do not use all of the gas they have firm contracts for on any given day for power burn in their full fleet? They sell it.

LNG Exports

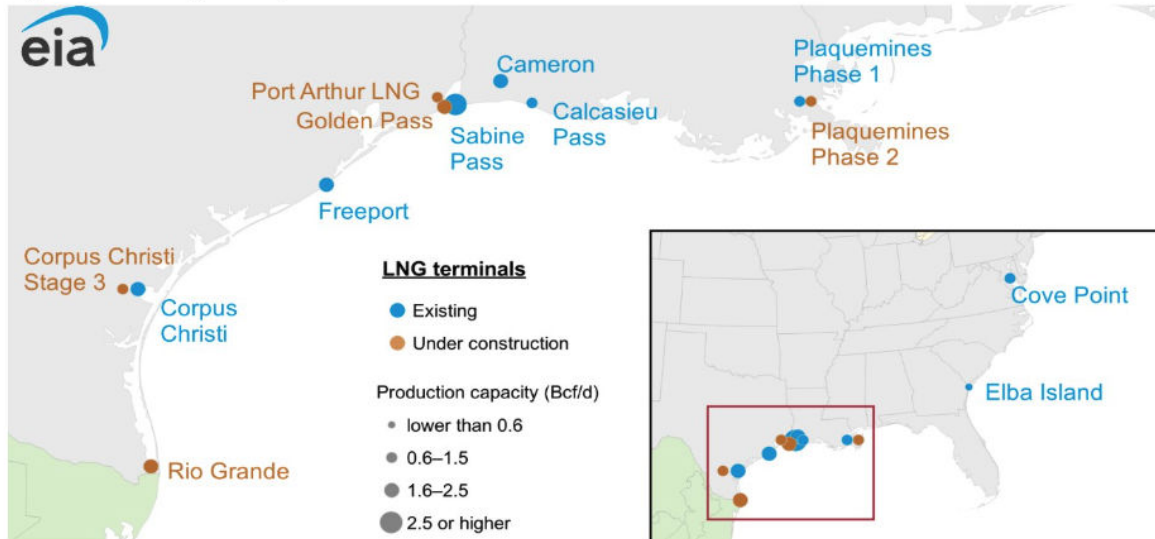
Electric utilities sell excess firm pipeline capacity to the same third-party pipeline capacity market that they purchase from for their peakers. Gas molecules in a pipeline are a little like cryptocurrency - they can be bought and sold without much scrutiny until they are "cashed out," or in the case of gas molecules, delivered and burned in a power plant or furnace.

The US became a net LNG exporter in 2019, and the rate of export has been increasing ever since. We are now the single largest exporter of gas in the world. The federal government has

already authorized the export of approximately 47% of our domestic gas production. The US' eighth LNG export facility came online at the end of 2024.¹⁶

These facilities are clustered in the Gulf of Mexico and on the East Coast (see map below).

United States liquefied natural gas export facilities, existing and under construction (as of January 2025)



Data source: U.S. Energy Information Administration, [Liquefaction Capacity File](#); trade press
Note: Bcf/d=billion cubic feet per day; LNG=liquefied natural gas

Source: US Energy Information Administration <https://www.eia.gov/todayinenergy/detail.php?id=64224>

The Williams Companies, Inc., the parent company of the Williams Transco pipeline that supplies Duke, Dominion, and Georgia Power, has been strategically increasing its investments in infrastructure such as LNG storage and joint ventures that increase access to Gulf LNG ports such as Cameron.¹⁷

*“This premier natural gas storage platform on the Gulf Coast fits squarely within our strategy to own and operate the best assets connected to the best markets **to serve growing demand driven by LNG exports and power generation,**” said Williams President and Chief Executive Officer Alan Armstrong. **“These assets better position Williams’ natural gas storage operations to serve Gulf Coast LNG demand and growing electrification loads from data centers along the Transco corridor.”**¹⁸ ~Alan Armstrong, CEO of The Williams Companies, Inc. (emphasis added)*

¹⁶ Source: US Energy Information Administration (EIA): <https://www.eia.gov/todayinenergy/detail.php?id=64224>

¹⁷ Source: <https://www.businesswire.com/news/home/20231227523874/en/Williams-Announces-Acquisition-of-Strategic-Gulf-Coast-Natural-Gas-Storage-Portfolio-with-Direct-Access-to-LNG-Export-Facilities-and-Interstate-Pipelines>

¹⁸ ibid

Making the Connections to LNG facilities

Kinder Morgan, another major fossil gas supplier to Southeastern utilities, has its own export facility called Elba Island on the Georgia coast in addition to Gulf of Mexico LNG export access.¹⁹ Elba Island has a pipeline called the Elba Express that connects Transco to the Elba Island export facility infrastructure. Both the Williams *Alabama Georgia Connector* and the Kinder Morgan *South System Supply Enhancement 4* projects will deliver gas to the Elba Express pipeline.

For Williams Transco and Gulf access, Sempra Infrastructure’s Cameron LNG Phase 1 export facility in Hackberry, Louisiana provides an important LNG export connection. Sempra describes its LNG business as being “**focused on securely delivering natural gas to the world** in support of the energy transition.”²⁰ (emphasis added)

Sempra notes in their 10-K filing with the Securities and Exchange Commission that one of North America’s advantages in the world LNG markets is high levels of developed and undeveloped natural gas resources as well as its “extensive natural gas pipeline transmission systems and natural gas storage capacity....”²¹ They further state:

*“Our LNG projects in development, under construction and in operation all compete globally to market and sell LNG to remarketers and end users, including gas and electric utilities located in LNG-importing countries around the world.”*²² -Sempra 2023 10-K (emphasis added)

Sempra Infrastructure also owns the Cameron Interstate Pipeline, a 40-mile fossil gas pipeline that **links Cameron LNG Phase 1 “to seven pipelines that offer access to major feed gas supply basins** in Texas and the northeast, midcontinent and southeast regions of the U.S. The majority of transportation capacity on the Cameron Interstate Pipeline is under long-term transportation service agreements with shippers for delivery to the Cameron LNG Phase 1 facility.”²³

And one of those seven pipelines is Transco.²⁴

¹⁹ “The Elba Liquefaction facility located on Elba Island in Chatham County, Georgia, is owned by ELC and includes 10 modular liquefaction units for a total capacity of approximately 2.5 million tonnes per year of LNG, which is equivalent to approximately 0.35 billion cubic feet (Bcf) per day of natural gas. ELC then delivers the LNG to Southern LNG Company, L.L.C. (SLNG) for export.” Source: <https://ir.kindermorgan.com/news/news-details/2022/Kinder-Morgan-Announces-Sale-of-Equity-Interests-in-Elba-Liquefaction-Company/>

²⁰ Source: Sempra 2023 10-K <https://www.sempra.com/sites/default/files/2023AnnualReport/2023-AR-Form-10-K.pdf> p. 20

²¹ *ibid* p. 22

²² *ibid* p. 22

²³ *ibid* p. 22

²⁴ Source: <https://www.gasnom.com/ip/CAMERON/> (Capacity: Operational Availability)

LNG Export Profits

These investment decisions are profitable.²⁵ ²⁶ As seen below, Williams and Kinder Morgan can facilitate and benefit from the sale of the excess gas molecules for LNG export for an average of \$9.328 per MMBtu (or per dekatherm) more than it is valued domestically.²⁷

U.S. Gulf Coast LNG Netback Prices (12-Month Strip)

NGI

Data as of 16-Jan-2025

	Futures Settle (\$US/MMBtu)			Est Shipping Cost from Gulf Coast (\$US/MMBtu)			Gulf Coast Netback (\$US/MMBtu)					Netback Less Henry Hub Futures (\$US/MMBtu)							
Spot Month (shipping based on spot market vessel rate)	Month	JPN/KOR	NBP	TTF	JPN/KOR	NBP	TTF	JPN/KOR	NBP	TTF	Max	Chg	HH	Diff (Margin)					
Mar-25		\$13.745	\$14.097	\$14.014	\$1.057	\$0.492	\$0.510	\$12.688	\$13.605	\$13.504	\$13.605	(\$0.133)	\$3.739	\$9.866					
Rest of Curve (shipping based on 1-Yr vessel rate, adjusted for seasonality)																			
Apr-25		\$13.865	\$14.041	\$14.078	\$1.142	\$0.535	\$0.558	\$12.723	\$13.506	\$13.521	\$13.521	(\$0.169)	\$3.681	\$9.840					
May-25		\$13.940	\$13.996	\$14.088	\$1.156	\$0.540	\$0.565	\$12.784	\$13.456	\$13.524	\$13.524	(\$0.176)	\$3.750	\$9.774					
Jun-25		\$14.075	\$13.964	\$14.149	\$1.201	\$0.562	\$0.589	\$12.874	\$13.403	\$13.560	\$13.560	(\$0.176)	\$3.926	\$9.634					
Jul-25		\$14.220	\$13.804	\$14.170	\$1.216	\$0.565	\$0.596	\$13.004	\$13.239	\$13.575	\$13.575	(\$0.168)	\$4.073	\$9.502					
Aug-25		\$14.280	\$13.871	\$14.181	\$1.263	\$0.590	\$0.622	\$13.017	\$13.281	\$13.560	\$13.560	(\$0.168)	\$4.097	\$9.463					
Sep-25		\$14.330	\$14.058	\$14.221	\$1.306	\$0.615	\$0.646	\$13.024	\$13.442	\$13.574	\$13.574	(\$0.176)	\$4.062	\$9.512					
Oct-25		\$14.165	\$13.813	\$13.969	\$1.460	\$0.696	\$0.733	\$12.705	\$13.117	\$13.236	\$13.236	(\$0.138)	\$4.114	\$9.122					
Nov-25		\$14.020	\$13.981	\$13.682	\$1.513	\$0.730	\$0.761	\$12.507	\$13.252	\$12.920	\$13.252	(\$0.070)	\$4.318	\$8.934					
Dec-25		\$14.140	\$14.146	\$13.627	\$1.459	\$0.701	\$0.728	\$12.681	\$13.445	\$12.899	\$13.445	(\$0.048)	\$4.711	\$8.734					
Jan-26		\$14.055	\$14.221	\$13.601	\$1.338	\$0.639	\$0.660	\$12.717	\$13.581	\$12.941	\$13.581	(\$0.034)	\$4.952	\$8.629					
Feb-26		\$14.055	\$14.131	\$13.473	\$1.255	\$0.594	\$0.610	\$12.800	\$13.537	\$12.862	\$13.537	N/A	\$4.616	\$8.921					
NTM Avg		\$14.074	\$14.010	\$13.938				\$12.793	\$13.405	\$13.306	\$13.497	\$13.497	\$4.170	\$9.328					
West of Suez Spot 174K XDF/MEGI Vessel Day Rate:					\$19,000					West of Suez 1-Yr TC 174K XDF/MEGI Vessel Rate:					\$35,000				

Source: CSI, Fearnleys, NGI calculations

Source: <https://naturalgasintel.com/news/more-us-lng-lands-in-europe-as-cargoes-divert-to-capture-stronger-prices/>

- Pipeline companies are entering into firm contracts with Southeastern utilities for millions of dekatherms of firm gas transportation.
- These expensive firm transportation contracts allow pipeline companies to raise the capital needed to build the pipeline expansion projects in the Southeast.
- But increasingly, *the gas molecules will flow to export.*

Paying to Widen the Highway

Another way to think about this is to envision these large Williams and Kinder Morgan interstate pipelines as highways built for the “transportation” of gas molecules. In the past, all of the traffic headed from south to north - gas from Gulf of Mexico rigs traveled up the East Coast. With the fracking boom in the Marcellus and Utica shale regions, toward the northern end of things, there

²⁵ See: <https://pgjonline.com/news/2024/november/williams-companies-exceeds-q3-profit-estimates-on-higher-revenue-boost-from-transco-pipeline>

²⁶ See: https://pgjonline.com/news/2024/december/kinder-morgan-predicts-higher-profit-in-2025-driven-by-natural-gas-pipelines?oly_enc_id=1249J689451217F

²⁷ “Netback” is essentially profit - the price a buyer is willing to pay for gas minus the cost to deliver it.

is now an oversupply of gas looking for offtakers. *At the same time, investment in LNG exports is booming.*

Our ratepayer dollars that pay for the Southeast utilities' (Duke, Dominion, Santee Cooper, Georgia Power) firm transportation contracts are paying to “widen” that highway as the flows reverse direction from north to south. Southeastern utilities' use of this gas in power plants can be likened to offramps along these highways, and these offramps will be used less and less.

Nature Abhors a Vacuum

As Duke, Dominion, Santee Cooper, and Georgia Power need less from the spot market (thanks to their expensive firm contracts), the excess gas molecules from one utility on a given day will *no longer flow to another Southeastern utility* in need of some extra molecules. Nature abhors a vacuum, and the continual increase in LNG export capacity is creating a giant sucking sound as more and more US fossil gas molecules are drawn toward more lucrative overseas markets and away from domestic markets.

Southeastern ratepayers are helping to finance the infrastructure that ultimately benefits 1) pipeline company shareholders and 2) foreign countries. The expansion is being paid for by Southeastern ratepayers, but the end consumers increasingly will be in foreign markets.²⁸ Yet these foreign countries are not listed in the applications to FERC as part of the “necessity” in the Certificate of Public Convenience and Necessity process that allows pipeline companies to use eminent domain to take control of private property in order to build these pipeline expansions.

In addition to paying to widen the highway, US ratepayers will pay higher electric bills due to the upward price pressure of the world fossil gas commodity market. A new study released by the Department of Energy Office of Fossil Energy and Carbon Management confirmed this finding.²⁹ **So as a thank you for helping to increase access to LNG export markets, Southeastern ratepayers also get higher prices.**

The study also found that the carbon footprint of LNG export gas is much higher than previously thought - even higher than that of coal. But LNG export operations continue to grow and grow and grow.³⁰ The DOE study indicates that there is 14.28 Bcf (or 14,280,000 dekatherms) of **online** US LNG export capacity, 11.57 Bcf **under construction**, and a total of 42.14 Bcf **authorized** by the DOE.³¹ Currently, about 20% of US fossil gas from the lower 48 states is

²⁸ Source: US EIA <https://www.eia.gov/energyexplained/natural-gas/liquefied-natural-gas.php>

²⁹ Source: US Department of Energy https://www.energy.gov/sites/default/files/2024-12/LNGUpdate_SummaryReport_Dec2024_230pm.pdf (accessed February 10, 2025)

³⁰ Source: EIA Today in Energy September 3, 2024
<https://www.eia.gov/todayinenergy/detail.php?id=62984>

³¹ *ibid* p. S-4

exported through pipelines to Mexico (to LNG ports) or as LNG via ship from the US.³² This percentage will only grow.

Opening Marcellus and Utica to the Southeast

The construction of the Mountain Valley Pipeline opened Transco up to considerably more fracked gas supply from the Marcellus and Utica regions around West Virginia. Production growth had previously been constrained by a lack of pipeline takeaway capacity.³³ To get that gas into the Southeast and toward the lucrative export market, MVP will need to increase its existing capacity - and this is already in the works. EQT announced on an earnings call that it will be pursuing a .5 Bcf per day (500,000 dekatherms per day) expansion, with more to come after that. They estimate demand at potentially up to 18 Bcf (18 million dekatherms) per day.³⁴

EQT sees that the LNG demand pull will increase prices for firm gas along Transco in the Southeast. From:

*“So, we think that market really in time becomes the **most premium market in the country** because you have a combination of LNG pulling gas away and a deeper deficit from all these other factors we’re talking about, whether it’s retirement of coal, whether it’s data center growth.*

*And so **that’s why the utilities, I think, are willing to pay the prices that they did to lock up reliable gas supply**. That’s the reason we’re so excited about expanding MVP and adding additional capacity because we think -- I mean, there’s a big demand sync (sic) being created in that market from both teams but it’s really the confluence of both of those big demand themes that’s going to drive that market where it is.”³⁵ - Jeremy Knop, Chief Financial Officer, EQT (emphasis added)*

³² Source: <https://rbnenergy.com/i-wanna-drive-you-home-padd-3-exports-surge-as-competition-intensifies-among-major-players>

³³ Source: EIA Today in Energy March 29, 2023 <https://www.eia.gov/todayinenergy/detail.php?id=56000>

³⁴ Source: https://www.sec.gov/Archives/edgar/data/33213/000121390024035837/ea0204602-425_eqtcorp.htm

³⁵ Source: https://www.sec.gov/Archives/edgar/data/33213/000121390024035837/ea0204602-425_eqtcorp.htm

Jim Welty, President of the Marcellus Shale Coalition, stated that one driver of demand for Appalachian region gas is “the increasing global market for liquefied natural gas (LNG) exports,” that the International Gas Union anticipates a world supply shortfall by 2030, and the Appalachian region is “well-positioned to address this looming gap.”³⁶

Gas Pipeline Companies Can't Lose

Southeastern states have become an all-you-can-eat buffet for the major pipeline owners and operators. The **load growth frenzy** has been used by utilities to try to justify building **more power plants** that they can earn a rate of return on, and the **power plants** have been used by the pipeline industry to justify building **more pipeline capacity**. We, the ratepayers, will pay for these assets, even as they are used less and less.

But the end game for pipeline companies is the lucrative LNG market, and they can't lose. We pay for their infrastructure, and either they sell the molecules to us at increasing prices, or the unused molecules are resold to foreign countries via the third-party market - where the same companies are players - for double what they can charge in the domestic market. This gas frenzy will continue to fuel climate change [catastrophes](#) - fires, floods, drought and famine.

Now is the time for regulators and consumer advocates to look critically at who will ultimately benefit from these proposed new gas plants and pipelines: customers, or just shareholders?

At SACE we will continue to daylight and oppose injustices such as this and boost clean energy solutions in the South through our work to decarbonize the electric sector and avoid the worst impacts of the climate crisis.



³⁶ Source:

https://read.nxtbook.com/gulf_energy_information/pipeline_and_gas_journal/january_2025/spotlight_on_marcellus_mcdonough.html