ELECTRICITY PRICE IMPACTS OF U.S. LNG EXPORTS ON FLORIDA CONSUMERS

Authored by EQ Research LLC for Environmental Defense Fund

April 2026

Electricity Price Impacts of U.S. LNG Exports on Florida Consumers

Authored By: EQ Research LLC
Prepared For: The Environmental Defense Fund
Supported By: VoLo Foundation
Date: April 2026

Note: This report and its supporting work do not incorporate or account for impacts of the current conflict in the Persian Gulf region. The analysis represented herein began in late 2025, and while the authors acknowledge the potential for sustained energy market impacts as a possible effect of the Persian Gulf conflict no attempt has been made to include or otherwise address such possibilities in this report due to the rapidly changing nature of the conflict and uncertainty regarding outcomes.

Table of Contents

Executive Summary 3

Introduction 5

Synopsis of Report Contents 5

Summary of Key Findings 5

Influence of Natural Gas Prices on Florida Electricity Rates 7

Historical and projected natural gas use for electricity generation 7

Natural gas costs to Florida electricity consumers 9

Factors influencing natural gas costs to Florida electricity consumers 16

Natural Gas Prices 16

Natural Gas Market Price Forecasts 20

Natural Gas Risk Management 23

LNG Exports and Natural Gas Prices 24

Natural Gas Market Developments 24

U.S. LNG Export Capacity 25

Geography of LNG Exports 27

Impacts of LNG Exports on the U.S. Natural Gas Market 30

LNG Market Dynamics 31

Sale and Purchase Agreements 32

Global Market Exposure 33

LNG Export Impacts on Natural Gas Prices & Risks 34

LNG Export Impact Studies 36

Analysis of LNG Export Impacts on U.S. Natural Gas Prices 38

LNG Export Impacts on Absolute Price Level 39

LNG Export Impacts on Price Volatility 41

Analysis of LNG Export Impacts on Florida Electricity Consumers 44

Key Risk Factors for Florida Electricity Consumers 44

Scenario Analysis 45

Conclusions 49

Executive Summary

Florida relies heavily on natural gas to generate electricity for residents and businesses, and this reliance is expected to continue for at least the next decade. Additionally, Florida imports over 99.9% of natural gas consumed in the state, and the state's electric power sector consumed 86.25% of natural gas imports in 2025 – about twice the national average of 43.2%. Natural gas costs and associated risks rest entirely on Florida's electricity consumers. Growth in liquefied natural gas (LNG) exports amplifies these risks and is very likely to increase electricity costs paid by Florida consumers.

LNG exports have increased from a negligible percentage to the equivalent of about 13.2% of domestic natural gas consumption in less than a decade, and LNG exports are projected to double[1] before the end of the decade to reach between 25% and 30% of domestic consumption.

LNG export volume currently represents under 15% of U.S. natural gas production, but to meet the projected increase in LNG export volume U.S. natural gas production would have to increase by about 20% from the current level by 2030 and by nearly 30% from the current level by 2035 to maintain the current balance between supply and demand, without accounting for other increases in domestic natural gas consumption such as the rapid rise in electricity demand due to data centers. The EIA's most recent forecasts in the AEO 2026 project growth in natural gas production of between 20% and 40% above 2025 levels by 2050, not including the High and Low Supply scenarios, with most of the growth in natural gas production projected to serve international markets via LNG exports.

Known LNG export facilities with export approval represent between 30% and 45% of AEO 2026 scenarios' projected U.S. dry natural gas production as early as 2037. These facilities commonly operate under contracts with fixed-price or minimum-volume terms for periods of 10 or 20 years, making this increasingly large share of demand mostly unresponsive to domestic market price signals.

The results project expected growth in LNG exports to increase domestic natural gas prices by 28.8% in 2030 relative to the EIA's Reference scenario, which rises to an increase of 46.9% by 2050 relative to the EIA's Reference scenario. By 2035, natural gas costs on the typical Florida household's monthly electric bill rise by $4.10 under the Reference scenario to $29.76, whereas these costs rise by $16.10 under the LNG export-Adjusted scenario to reach $41.76 per month. Overall, for Florida's investor-owned utilities (IOUs) combined, the cumulative impact over the next decade of LNG export growth is expected to result in additional natural gas costs to Florida electricity consumers of between $18.48 billion and $22.32 billion compared to the EIA's Reference and Low Supply scenarios, respectively.

---

[1] https://www.eia.gov/todayinenergy/detail.php?id=66384

The prospect of these large electricity cost increases highlights the value to utilities of taking a holistic approach to managing natural gas price risk. One such approach is to optimize utilities' generation portfolios, by diversifying energy resources to minimize their risk exposure to a single fuel source. In Florida, solar energy in particular presents an abundant, stable, and low-cost alternative to lessen the state's dependence on natural gas and reduce exposure to the increasingly globalized gas market.

Introduction

Synopsis of Report Contents

EQ Research was engaged to conduct a three-phase study of fuel cost impacts and management across Florida's major investor-owned utilities (IOUs): Florida Power and Light (FPL)[2], Duke Energy Florida (DEF), and the Tampa Electric Company (TECO).[3] Phase One of this study was focused on developing a picture of how fuel costs have varied over time, their relative role as components of residential retail rates, the sources and magnitude of customer rate volatility, and how this may change in the future.[4]

This report comprises Phase Two of this larger study and is focused on analyzing the potential impacts on the fuel costs and customer electric bills of each of Florida's electric IOUs resulting from an increase in exports of U.S. liquefied natural gas (LNG). This report builds on the results of the Phase One study by evaluating a variety of LNG export-related factors' influence on natural gas prices and the resulting electric bill impacts under several timeframes. Specific topics addressed in this report include:

- How natural gas prices and risks affect electricity prices for Florida consumers;
- Influence of LNG exports on the U.S. natural gas market;
- Impacts of LNG export growth on U.S. natural gas prices and related risks; and
- Projected impacts on Florida electricity prices attributable to LNG export growth.

Summary of Key Findings

The key findings from this analysis are as follows:

- Florida's electric IOUs are highly reliant on natural gas for electricity generation and are expected to remain so over at least the next decade;
- Florida electricity consumers bear the entire burden of natural gas price and reliability risks;

---

[2] This includes FPL's Northwest Florida division, which was served by Gulf Power prior to the purchase of Gulf Power by FPL's parent company NextEra Energy in 2019. The former Gulf Power territory was fully consolidated into FPL operations in January 2022. In a historic context, we sometimes refer to FPL and Gulf Power separately, or to the two utilities combined (FPL/Gulf Power) depending on the context. On a forward-looking basis, we refer to the merged utilities as FPL.

[3] Florida Public Utilities, a small IOU has not been included in this analysis.

[4] The Phase One report, *Analysis of Florida IOU Fuel Costs and Rate Impacts on Residential Customers*, was released in October 2025 and is available at https://eq-research.com/eq-publications/florida-iou-fuel-costs/

- Growth in LNG exports is likely to increase price volatility and overall price levels for natural gas, which results in increased electric price volatility and higher electric prices for Florida consumers;
- The extent and impact of LNG exports on Florida electricity consumers varies by electric IOU, depending on the IOU's planned future reliance on natural gas for electricity generation;
- Increased LNG export growth is expected to result in an electric price increase for Florida's residential consumers that is nearly 300% higher than the baseline projection by 2035; and
- LNG export growth is projected to increase natural gas costs to Florida's residential electricity consumers by $18.5 billion cumulatively over the next decade.

Influence of Natural Gas Prices on Florida Electricity Rates

Florida's major IOUs are heavily reliant on natural gas for power generation and increased their reliance on natural gas between 2016 and 2024. Electricity consumers in Florida bear all the price risk associated with natural gas reliance. Florida's electric power sector has consumed more natural gas since 2010 than the electric power sector in any other state except Texas.[5]

Florida also imports over 99.9% of natural gas consumed in the state, and the state's electric power sector consumed 86.25% of natural gas imports in 2025 – about twice the national average of 43.2%.[6] This combination of heavy reliance on natural gas for electric power, dependence on imports, and the concentration of gas use for electricity generation makes Florida's electric power customers uniquely vulnerable to electricity price fluctuations resulting from changes in natural gas prices.

Compared to other sources of electricity generation, the cost of natural gas-fueled electricity generation is subject to a high degree of volatility resulting from fluctuations in the natural gas commodity price. In addition to price risk, high reliance on natural gas also has implications for operational risk, or the extent to which a utility is able to meet electricity demand during events when natural gas supply is disrupted or constrained.

Because changes in the commodity price of natural gas are passed on to electricity customers, Florida consumers bear all the exposure to natural gas price risk and the resulting impacts on electricity costs. The level of risk exposure varies by utility in proportion to a utility's reliance on natural gas for electricity generation.

The rapid and continuing growth in exports of LNG alters the dynamics of natural gas markets and introduces a new source of natural gas price uncertainty with the potential to magnify electric ratepayer exposure to natural gas-related risks over the next few decades. These risks are compounded by rapidly growing domestic demand for electricity to serve new large loads such as data centers and broader electrification trends, particularly within the Southeast region which is dependent on limited natural gas pipeline transportation capacity.

Historical and projected natural gas use for electricity generation

Natural gas represented 72.1% of the electric generation supply mix for Florida's major IOUs in 2025, an increase from 66% of the generation supply mix in 2016. The recent increase in natural gas reliance is mostly attributable to a 30% increase in natural gas generation by TECO and a 25.5% increase by DEF, while the share of natural gas generation for FPL/Gulf remained at about 70% over the period from 2016-2025.

---

[5] EIA. Natural Gas Delivered to Electric Power Consumers. http://www.eia.gov/dnav/ng/ng_cons_sum_a_epg0_veu_mmcf_m.htm

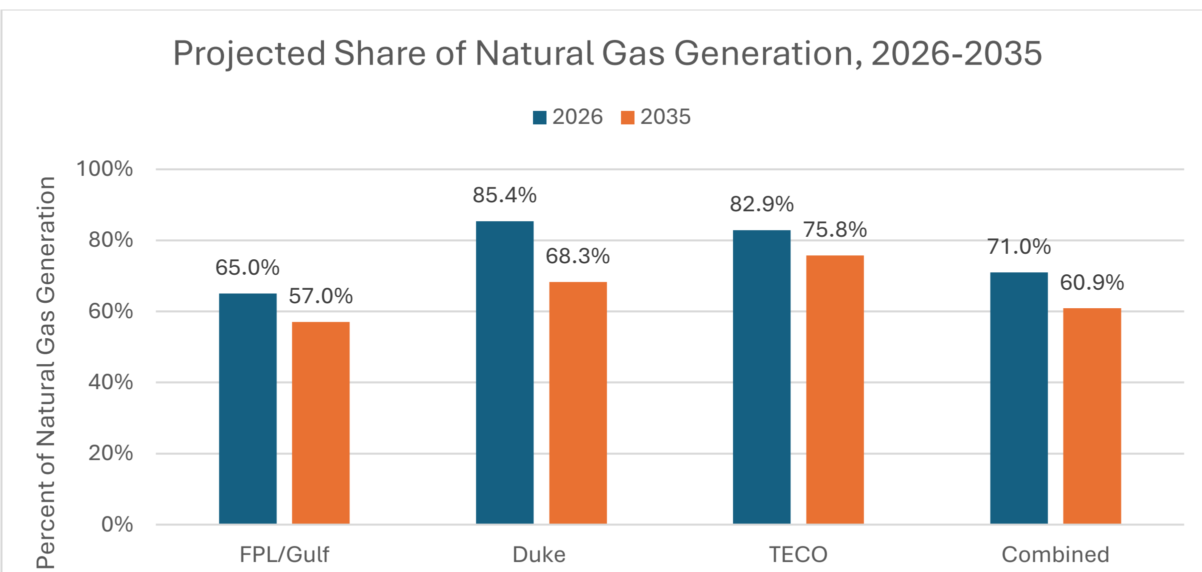
[6] https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SFL_a.htm

Combined, the major IOUs' 2026 Ten-Year Site Plans[7] filed with the Florida Public Service Commission (FPSC) projected their combined share of natural gas-fueled electricity generation to decline from 72.1% in 2025 to 60.9% in 2035. The IOUs' combined natural gas reliance increased significantly in the 2026 Plans compared to the 2025 Plans, with the share of electricity generation from natural gas rising from the 2025 projection of 53.3% in 2034 to 61.6% in the 2026 Plans.

The major IOUs project their combined total electricity generation to increase by 18.8% from 211,194 GWh in 2026 to 250,929 GWh in 2035, while over the same period the electricity from natural gas is projected to increase 1.9% from 149,989 GWh in 2026 to 152,798 GWh in 2035. The 2026 Ten-Year Site Plans show a major shift in Florida IOUs' natural gas usage from the 2025 Plans. In the 2025 Plans total combined electricity generation was projected to increase 9.7% and electricity generated by natural gas was projected to decrease by 18%, but in the 2026 Plans growth in total combined electricity generation doubled to 18.8% and electricity generated by natural gas is now projected to increase by 1.9%.

The large swing in projected natural gas use is nearly entirely attributable to a 40% increase in projected natural gas-fueled generation by FPL/Gulf, the largest of the three major IOUs. In its 2025 Plan, FPL/Gulf projected natural gas generation to decline by about 21,366 GWh over 10 years, but in its 2026 Plan it now expects natural gas generation to increase by 7,770 GWh over the next decade. The change in natural gas generation as a percentage of total generation from 2026-2035 for each IOU and the combined IOUs is shown in Figure 1.

Figure 1 - Projected Natural Gas Share of Generation by IOU, 2025-2034



[7] FPSC. Ten-Year Site Plans. https://www.psc.state.fl.us/ten-year-site-plans. The Ten-Year Site Plans are similar to integrated resource plans (IRPs), but have a number of key differences (e.g., informational only, less extensive, etc.).

The Florida IOUs' Ten-Year Site Plans changed significantly with respect to natural gas and solar generation between the 2025 and 2026 versions. In the 2025 Plans, growth in solar generation was forecast to exceed both the combined 26,918 GWh decline in natural gas generation and the 20,405 GWh increase in overall generation, but in the 2026 Plans natural gas generation is now expected to increase by nearly 3,000 GWh and growth in solar generation declined by about 10%. The expiration of the federal tax credit for solar power, expected load growth from large loads such as data centers and manufacturing facilities, and the proposed repeal of greenhouse gas (GHG) emission standards for fossil fuel generators[8] will likely impact future projections of both overall electric generation and the percentage of generation provided by natural gas.

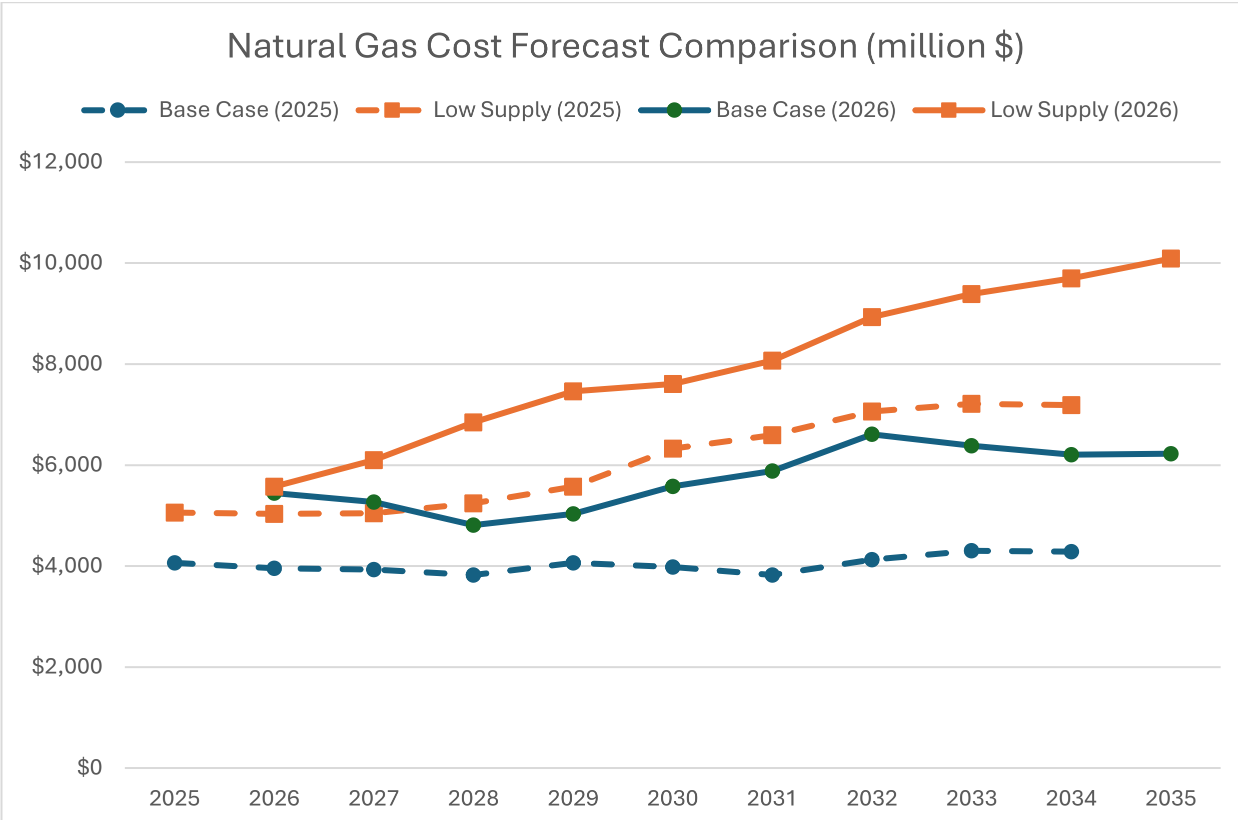
Natural gas costs to Florida electricity consumers

In the IOUs' 2025 Plans, the projected decline in natural gas consumption was offset by the projected increase in natural gas prices for a projected 5.5% increase in total natural gas costs; however, as a result of the increased natural gas consumption combined with higher expected prices in the 2026 Plans, total natural gas costs are now expected to increase by 14.3% over the next decade. Figure 2 compares the 2025 Plans' and the 2026 Plans' projected natural gas cost for the combined IOUs based on each IOU's gas generation projections and the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) price scenarios.[9] The expected total natural gas cost in 2034 under the 2026 projections is 44.8% higher than it was under the 2025 projections.

[8] *See* https://www.federalregister.gov/documents/2025/06/17/2025-10991/repeal-of-greenhouse-gas-emissions-standards-for-fossil-fuel-fired-electric-generating-units

[9] Natural gas costs are based on price scenarios from the EIA's 2025 and 2026 Annual Energy Outlook and the three IOUs' 2025 and 2026 Ten-Year Site Plan forecasts of natural gas consumption.

Figure 2 – Comparison of Natural Gas Cost Forecast for Florida's Major IOUs Combined, 2025-2035



There are several factors influencing overall natural gas cost to Florida's major electric IOUs, including each IOU's forecasted amount of natural gas-fueled electricity generation, the efficiency of natural gas power generation, and the EIA's price forecast scenarios. Within these gas cost forecasts, natural gas price increases are partially offset by utility projections of natural gas declining as a share of total electricity generation.

To examine ratepayer impacts, projected natural gas costs for each IOU are calculated per megawatt-hour (MWh) of expected natural gas generation, then distributed across all electricity sold by the utility to reflect the natural gas-related cost of each MWh to which the fuel recovery charge is applied, and the estimated impact on monthly residential electricity bills is based on a typical[10] Florida residential customer's monthly use of 1,000 kWh (i.e., 1 MWh).

[10] *See* FP&L, Exhibit TCC-2, p. 1. Florida PSC, Docket No. 20250011-EI. https://www.floridapsc.com/pscfiles/library/filings/2025/01187-2025/01187-2025.pdf and Duke Energy Florida Press Release, https://www.duke-energy.com/home/billing/def-rates-2024.

Under EIA's Base Case (Reference scenario) forecast, as shown in Figure 3, the natural gas portion of a typical monthly residential electric bill for all IOUs combined declines by $0.98/month, or 3.8% between 2026 and 2035, but under the Low Supply scenario increases by $13.82/month, or 52.4%. The monthly bill impact in each forecast year for a typical residential customer for the combined IOUs, FPL, DEF, and TECO is shown in Figure 4, Figure 5, Figure 6, and Figure 7, respectively.

Figure 3 - Monthly Bill Impact for Typical Florida Residential Customer

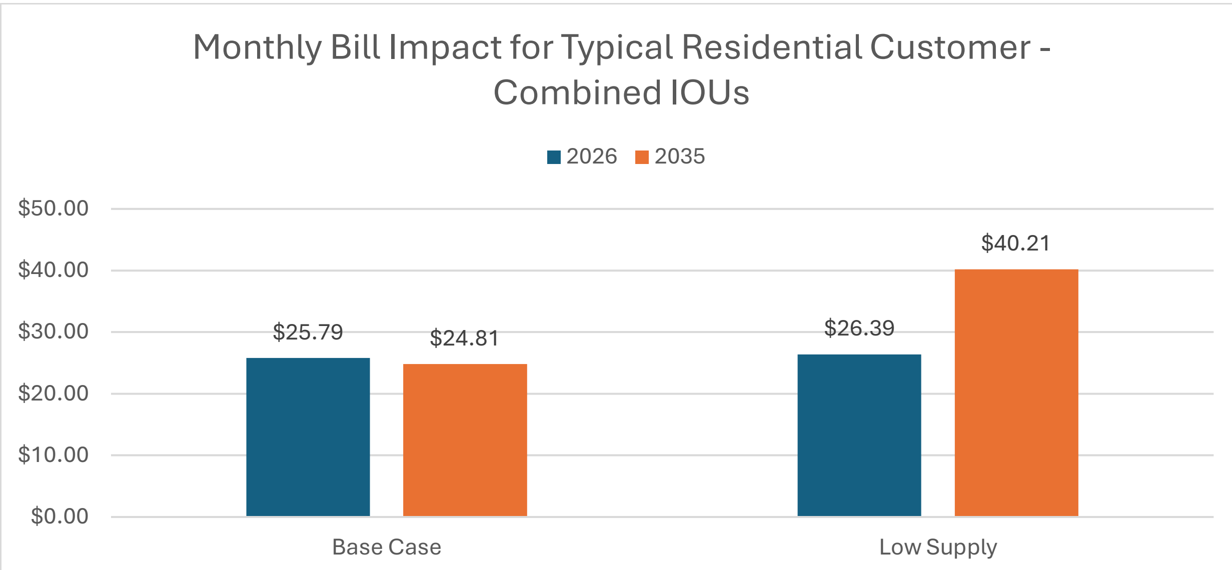


Figure 4 - Monthly Bill Impact for Typical Residential Customer - FPL

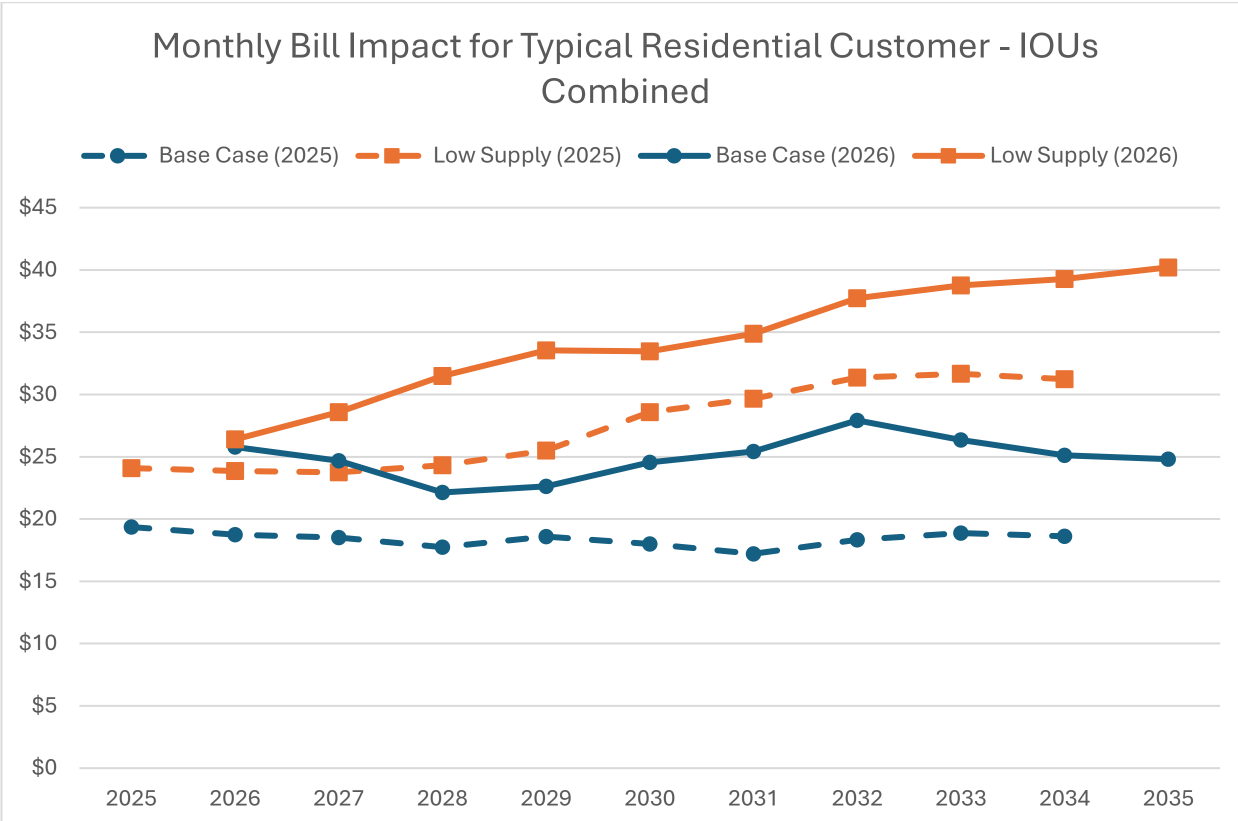


Figure 5 - Monthly Bill Impact for Typical Residential Customer - FPL

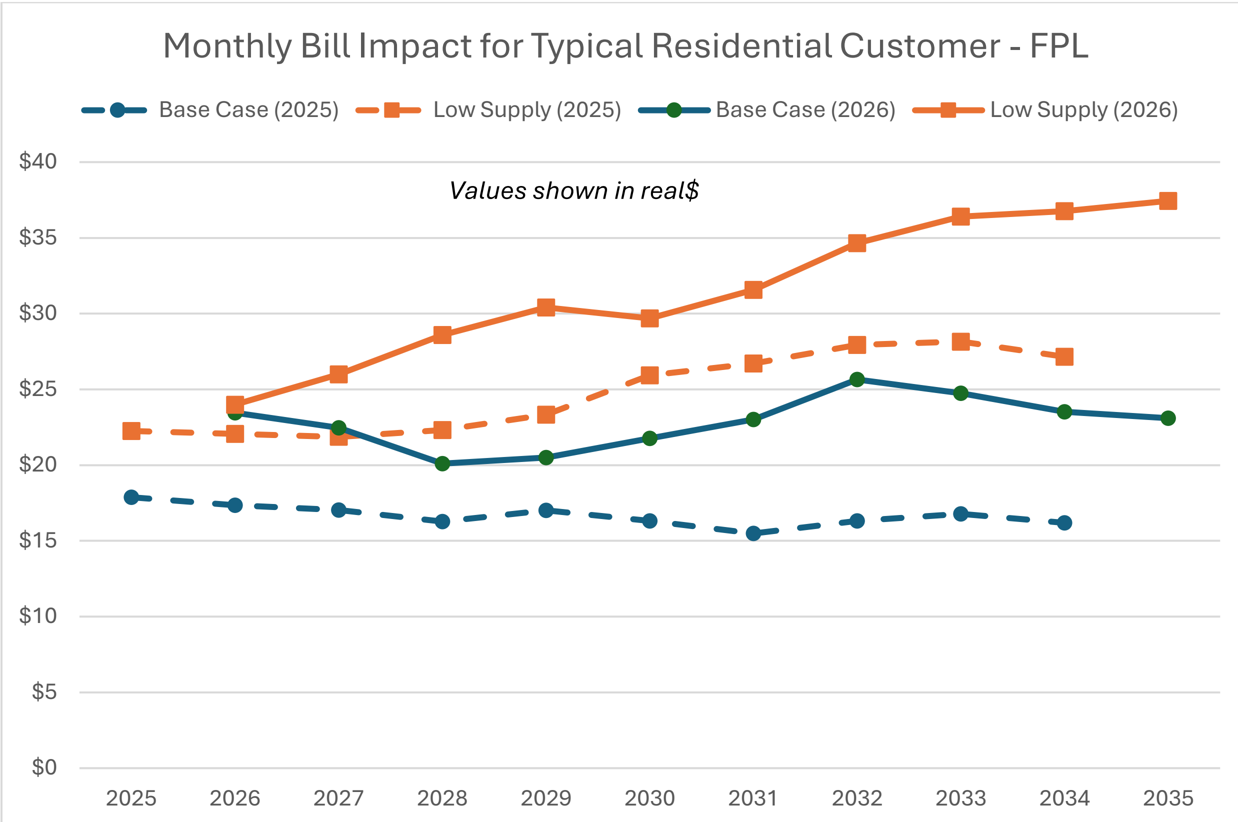


Figure 6 - Monthly Bill Impact for Typical Residential Customer - Duke

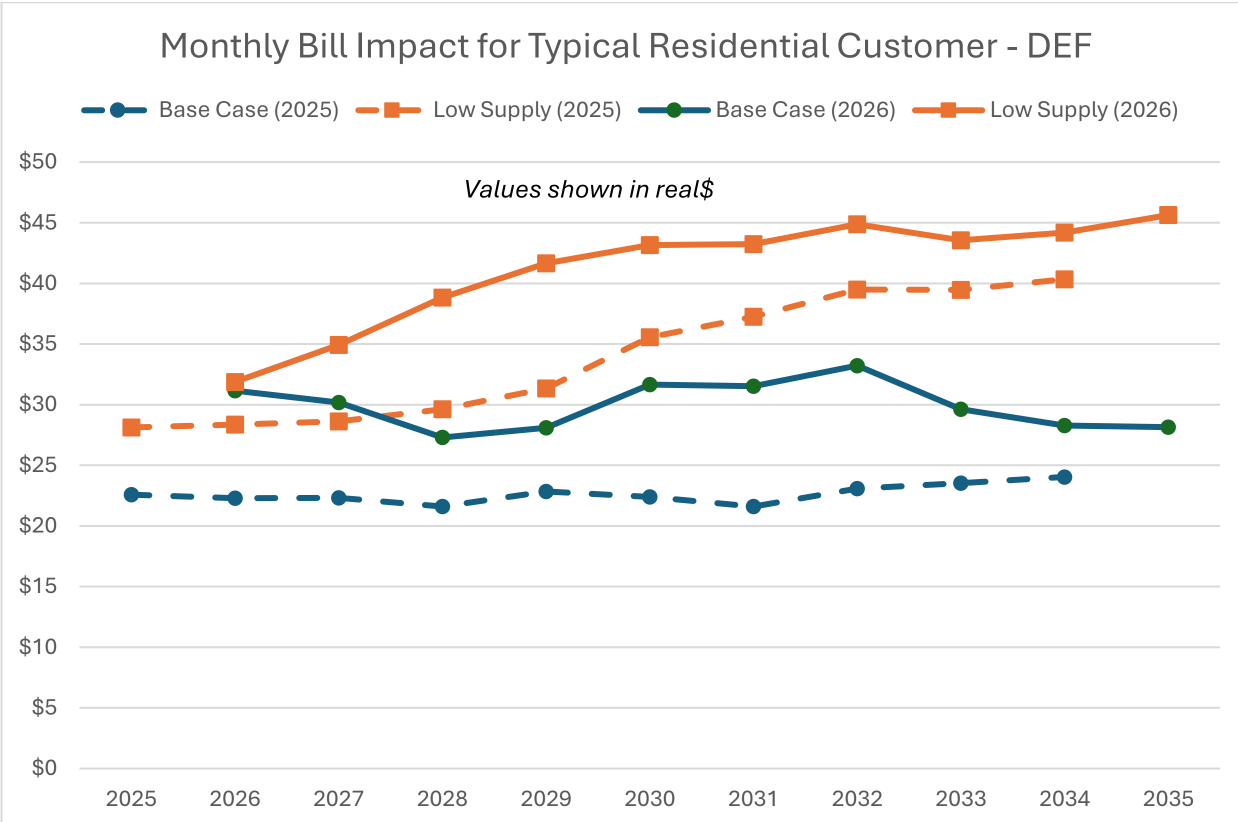
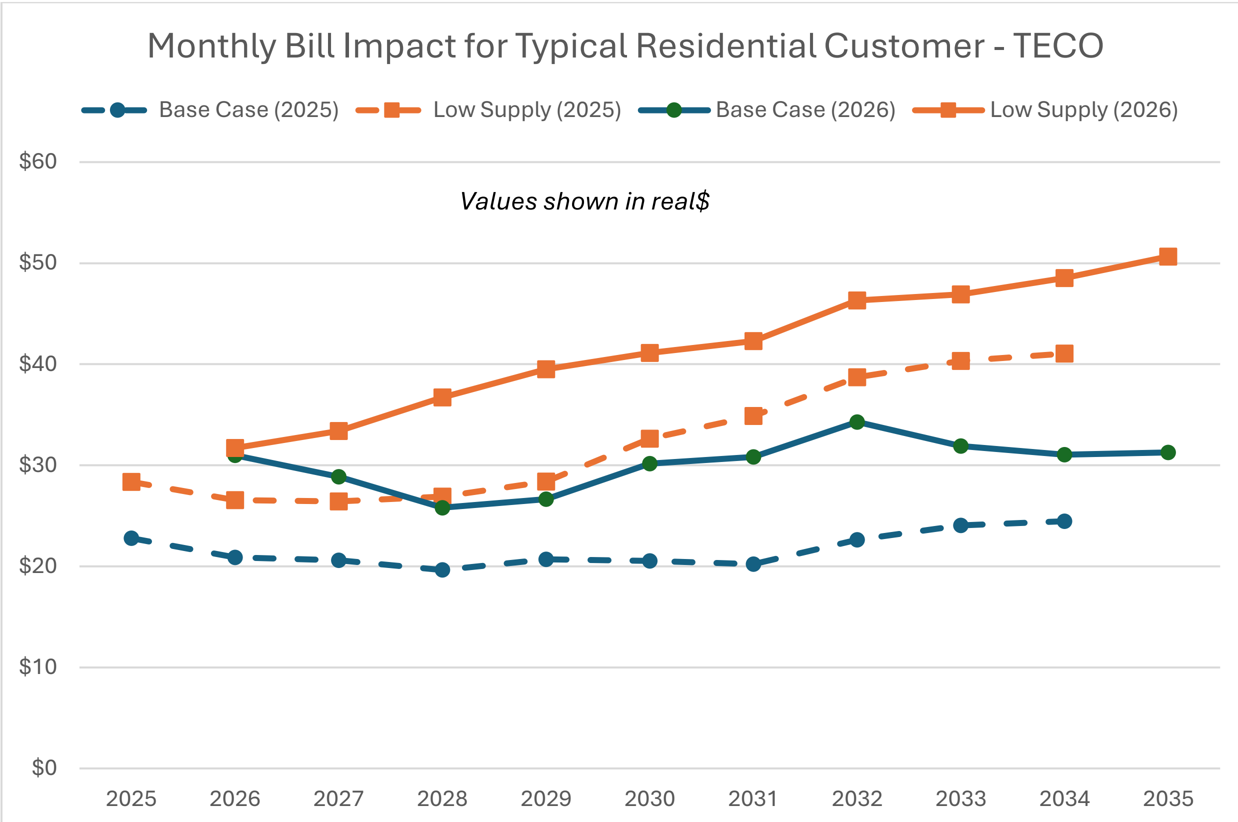


Figure 7 - Monthly Bill Impact for Typical Residential Customer - TECO



Factors influencing natural gas costs to Florida electricity consumers

The cost of natural gas generation to Florida ratepayers is influenced by a variety of factors, the most basic of which include:

- Price of natural gas – including the commodity cost and pipeline transportation cost;
- Percentage of electricity generation from natural gas – a factor influenced by total electricity demand and generation from non-fuel sources such as solar; and
- Efficiency of natural gas-fueled electricity generation – a factor depending partly on each utility's generation portfolio (e.g., capacity of combustion turbines vs. capacity of combined cycle units) as well as how the generation portfolio is dispatched.

Of these three basic factors, the price of natural gas tends to be the most volatile, difficult to accurately predict, and yet the most meaningful driver of cost. The other two factors are driven by utility planning and analysis, but those factors tend to change slowly over time as the influence of an individual new generation facility is moderated by the existing generation fleet.

Natural Gas Prices

Natural gas prices over the long term are driven by fundamental economic forces of supply and demand, but natural gas prices are difficult to accurately forecast because of the wide variety of factors that influence the market. Natural gas production is steady over short time periods, influenced by incremental reductions in the output of existing wells and the addition of new wells. But because natural gas demand fluctuates significantly throughout the year, with seasonal peak demand often about 50% higher than demand in other months, actual market prices fluctuate significantly compared to the annual average price.[11]

In addition to seasonal price fluctuations, unexpected large changes in demand or supply over brief periods of time, often due to extreme temperature events or unexpected supply disruptions, drive brief but very large increases in the market price. Over longer periods of time, natural gas prices are influenced by fundamental shifts in supply or demand, such as increased supply from shale formations due to advances in hydraulic fracturing and horizontal drilling extraction techniques or widespread increased adoption of natural gas-fueled electricity generation.

[11] *See* https://www.eia.gov/todayinenergy/detail.php?id=22892 and https://www.eia.gov/todayinenergy/detail.php?id=64845

The uncertainty and volatility of natural gas prices from day-to-day, season-to-season, and year-to-year presents a price risk to electricity consumers, a risk that is magnified by the degree of reliance on natural gas. For electricity consumers, volatility in natural gas prices often results in higher unpredictable electric bills. This price volatility manifests in several primary forms which can be categorized based on their predictability, magnitude, and duration.

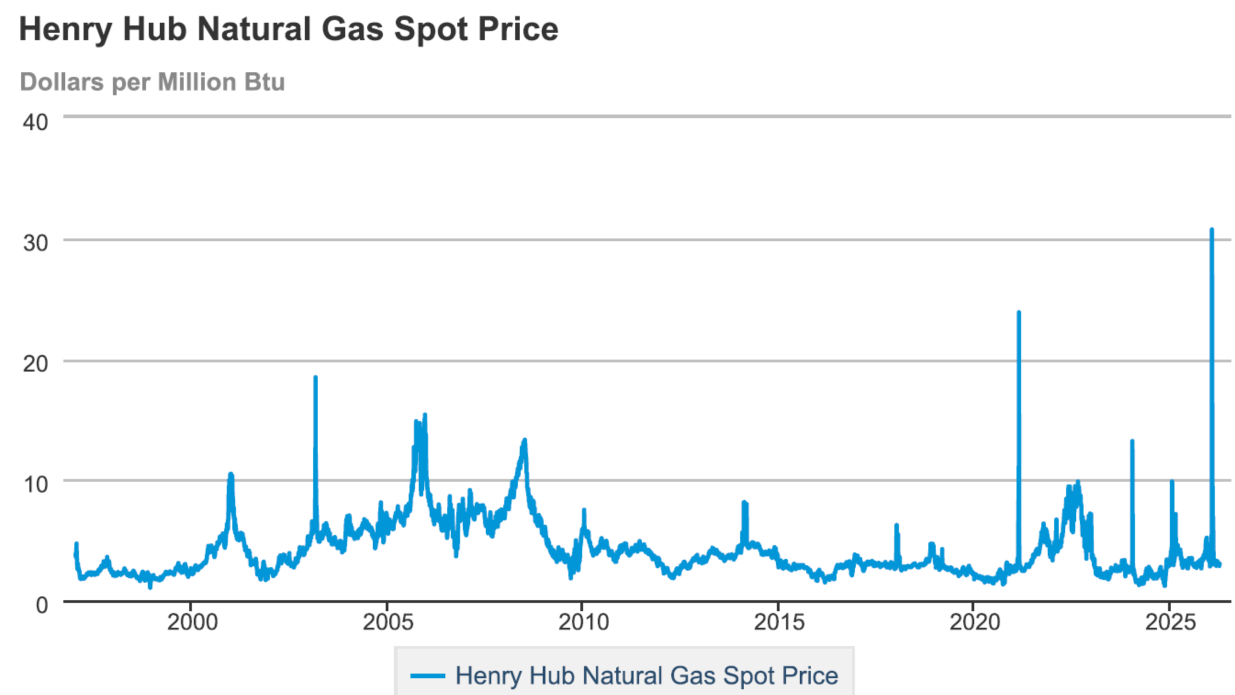
Table 1 - Natural Gas Price Events

	Predictability	Magnitude	Duration
Spike	Low: immediately prior to event, i.e. days ahead	Low impact on annual cost	Days
Seasonal	High: annually recurring pattern	Moderate	Months
Bubble	Very Low: highly unpredictable	Very High	Years

A Spike event is characterized by a rapid large price movement of short duration, often in response to an extreme weather event. Spike events are visible in charts showing high-frequency prices (i.e. daily) such as in Figure 8 below.[12] While Spike events look dramatic and can be attention-grabbing, they ultimately have a minimal impact on annual electricity costs because they start and stop within a few days and represent about 1%-2% of annual electricity prices.

[12] Chart from https://www.eia.gov/dnav/ng/hist/rngwhhdD.htm

Figure 8 - Henry Hub Daily Natural Gas Spot Prices



THOMSON REUTERS

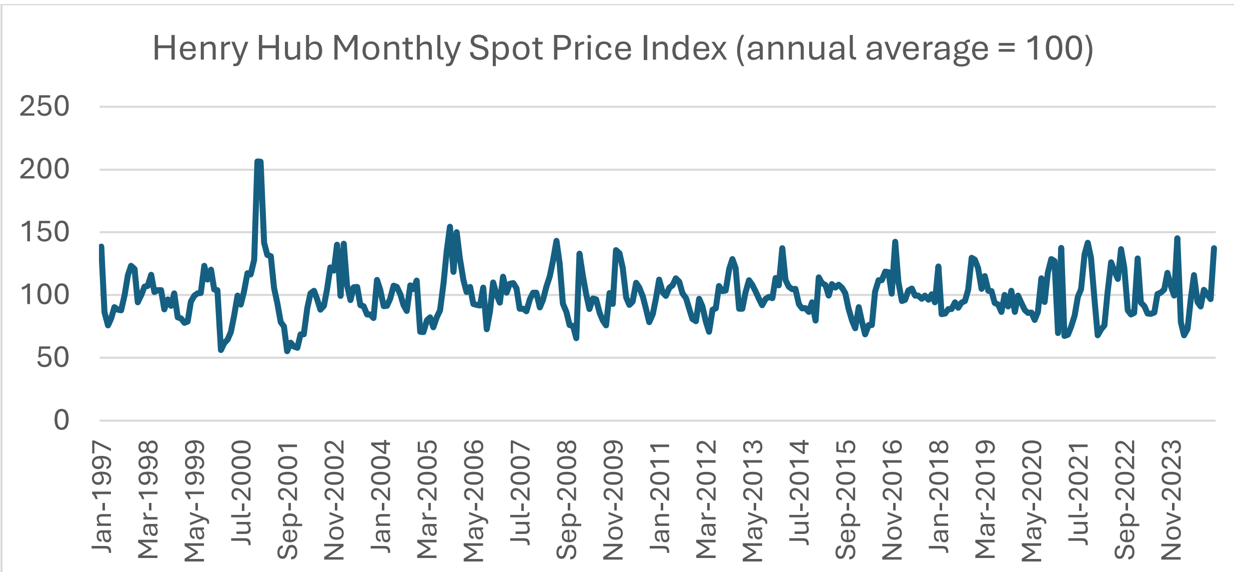
For example, on February 25, 2003 the Henry Hub[13] spot price reached $18.48/MMBTU – more than 300% above the price a week prior on February 18, 2003 and 140% above the price a week later on March 4, 2003. An even greater magnitude Spike event occurred on February 17, 2021 when the Henry Hub spot price reached $23.86/MMBTU – 535% higher than the price of $3.76/MMBTU on February 10, 2021 and 752% higher than the price of $2.80/MMBTU a week later on February 24, 2021.

Seasonal price fluctuations are the most predictable types of natural gas price changes because they are driven by changes in demand during summer and winter months. Seasonality occurs to some degree every year with the magnitude of the Seasonal event dependent on how extreme or mild summer and winter temperatures are over a period of months. [14]

[13] The Henry Hub is the physical location for natural gas delivery located in Louisiana and prices for this delivery point are widely considered the benchmark U.S. natural gas price.
[14] https://www.eia.gov/todayinenergy/detail.php?id=22892

For example, an abnormally cold winter with persistent below-average temperatures will result in elevated natural gas prices for a period of a month or more, which impacts annual electricity costs as increased consumption drives prices higher for 10%-25% of a year. Figure 9 shows average monthly prices indexed to the average annual price, where the average annual spot price equals 100. Using an indexed value removes the effects of changes in the absolute price level and expresses monthly prices relative to the annual average and demonstrates seasonality by indicating how monthly prices fluctuate around the average price in each year.

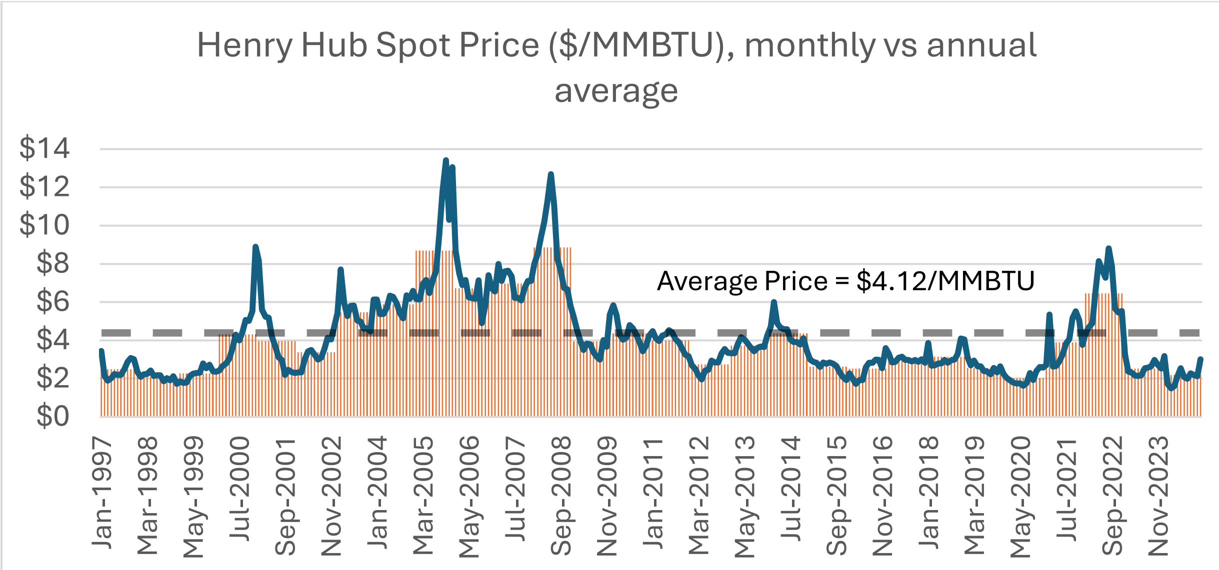
Figure 9 - Henry Hub Spot Price monthly price index (annual average = 100)



Bubble-type events have the highest magnitude of impact on annual electric costs because they are characterized by elevated prices that persist for a duration of about a year or more. Unlike Spike events where the cost impact is averaged out, or Seasonal events that can be mitigated or managed with hedging strategies, the cost impacts of Bubble events are difficult to manage or mitigate. Furthermore, these periodic events are difficult if not impossible to accurately predict the timing of, as they are often the result of an imbalance in supply and demand, yet have a high likelihood of occurring every 5-10 years.

The most recent occurrence of this type of periodic event was following COVID-19 when natural gas spot prices reached a low averaging $1.76/MMBTU in June 2020 and then rose more than 400% over the next two years to an average of $8.81 in August of 2022, as shown in Figure 10.

Figure 10 - Henry Hub Spot Price ($/MMBTU), monthly vs annual average



Natural Gas Market Price Forecasts

As previously discussed, natural gas prices in the U.S. are highly volatile over a wide range with monthly average prices over the past 25 years ranging between $1.49/MMBTU and $13.42/MMBTU. This volatility is fundamentally driven by imbalances in supply and demand, the limited amount of natural gas storage, and the speed and ability of response of both supply and demand to market signals such as price.

Natural gas price forecasting is imprecise at best, with neither financial markets nor modeling showing consistent or particularly accurate results. For instance, a 2005 paper from Lawrence Berkeley National Lab that compared the results of both EIA modeling and Henry Hub futures prices with actual prices found that the Henry Hub futures price underestimated the natural gas price by 11.5% ($0.35/MCF) between 1996 and 2003 and the EIA's Annual Energy Outlook modeling underestimated prices by 23.4% ($0.71/MCF).[15]

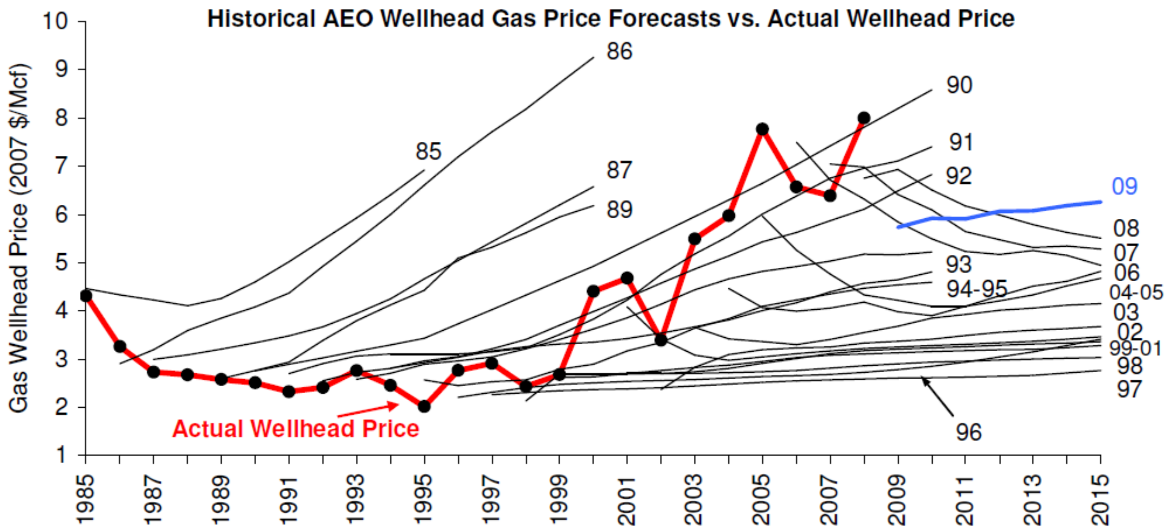
Figure 11, from Lawrence Berkeley National Lab[16], compares actual natural gas prices to EIA price forecasts in the AEO. Natural gas price forecasts have tended to capture the general directionality of price movements even if not the timing or magnitude of those price movements. Behind the scenes of the figure below are several historical developments or inflection points in the maturation of natural gas markets.

---

[15] https://eta-publications.lbl.gov/sites/default/files/natural_gas_prices_forecast_cmparison-aeo_vs._natural_gas_markets_lbnl-55701.pdf
[16] https://www.osti.gov/servlets/purl/948129

The natural gas market was undergoing complex regulatory restructuring during the 1980s and early 1990s that resulted in an abundance of supply and EIA forecasts during this period continually reflected the expectation that the mismatch between supply and demand would be resolved and prices would revert and rise again to a level supporting new gas production replacing exhausted gas resources. The expected supply-demand balance and resulting reversion of natural gas prices that was reflected in EIA forecasts from the mid-1980s through the early 1990s did occur and while the EIA forecasts during this period are not aligned with actual gas price movements the reason for the misalignment is more about the timing of this regulatory restructuring inflection point than it is about the economic fundamentals.

Figure 11 - AEO Price Forecasts vs. Actual Prices



In the mid-1990s the EIA changed its forecast methodology, which resulted in a series of forecasts with relatively flat prices that were ultimately considerably below actual prices. However, the new methodology did not account for the increased demand and low investment in new natural gas supply resources that resulted from the extended preceding period of low prices, nor did it foresee the rapid economic growth of the late 1990s. The next methodology change occurred in 2003 and resulted in forecasts of falling prices, which did eventually occur but not until several years later as a result of new extraction technologies expanding the available supply at the same time as a global economic downturn.

A 2012 study conducted by NERA Economic Consulting[17] examined 15 years of EIA natural gas price forecasts and found an average error of about 29% and an error range of -$6.44/MCF and $3.85/MCF. The same study found that National Petroleum Council predictions were no better than those of the EIA over periods longer than about two years, and NYMEX futures prices erred by about 20% and the error increased with time. Private investor predictions fared no better and maybe even worse as demonstrated by the numerous high-level references from the early-2000s about the critical need for new U.S. LNG *import* facilities.

In short, the natural gas system has very little "slack" as nearly all gas production is delivered directly for consumption at the time it is produced. The result is that unexpected changes in supply or demand cause a market imbalance and are rapidly reflected in market prices. Some changes like an abnormally cold week may persist only for days, others like demand growth due to widespread replacement of coal with natural gas for power generation or rapid growth in demand for new power generation such as that driven by data centers needed to power artificial intelligence technology may persist for years.

The fundamentals of the natural gas market are highly sensitive to imbalances in supply and demand, and rapid and large price shifts occur in response to the weather, technology, economic trends, geopolitics, and even industrial accidents. The influence of these types of unpredictable events on natural gas prices is generally understood, but the timing of natural gas price movements is as difficult to predict as the types of events that cause these price movements, such as an industrial accident at a major LNG export terminal, abnormally cold weather next year, or the invasion of one country by another.

In the absence of such exogenous shocks to supply or demand, natural gas prices are reasonably predictable as supplies tend to adjust in response to known future events, such as the construction of new LNG export facilities. For instance, the basic economic concepts of supply and demand indicate that the price of natural gas will increase in response to a sustained large increase in demand from LNG exports. Even absent unexpected events, a 20%-30% or greater increase in natural gas demand will require additional supply and each unit of additional supply will come at a slightly higher incremental cost than the last.

[17] https://downloads.regulations.gov/EPA-HQ-OAR-2013-0602-22907/attachment_3.pdf

Natural Gas Risk Management

The more reliant a utility is on natural gas generation, the more exposure its customers have to natural gas-related risks. Some risks such as price risk can be partially managed over periods of a few years through hedging strategies such as using futures or options contracts to establish maximum prices for all or a portion of a utility's expected natural gas needs, while other risks such as operational risks can be managed through guaranteed contracts for pipeline transportation capacity or supply in order to increase the likelihood of gas being available for electricity generation during times of high demand and constrained capacity or limited supply.

However, those types of risk management approaches are natural gas-specific, do not fully eliminate certain key risks, and add to the cost of natural gas. One recent example of how hedging and contract guarantees are not foolproof mitigations of risk is the May 2021 ransomware attack on Colonial Pipeline's billing system which shut down pipeline delivery of petroleum products along the east coast for nearly a week.[18] Other risk-management approaches involve a more holistic approach, such as optimizing a utility's generation resource portfolio to minimize risk exposure to a single commodity through energy resource diversification. Resource diversification is the only available approach to reduce risks associated with high reliance on a single resource.

[18] *See* https://www.cisa.gov/news-events/news/attack-colonial-pipeline-what-weve-learned-what-weve-done-over-past-two-years, https://www.law.georgetown.edu/environmental-law-review/blog/cybersecurity-policy-responses-to-the-colonial-pipeline-ransomware-attack/#_ftn10, and https://houstonlawreview.org/article/73666-cybersecuring-the-pipeline

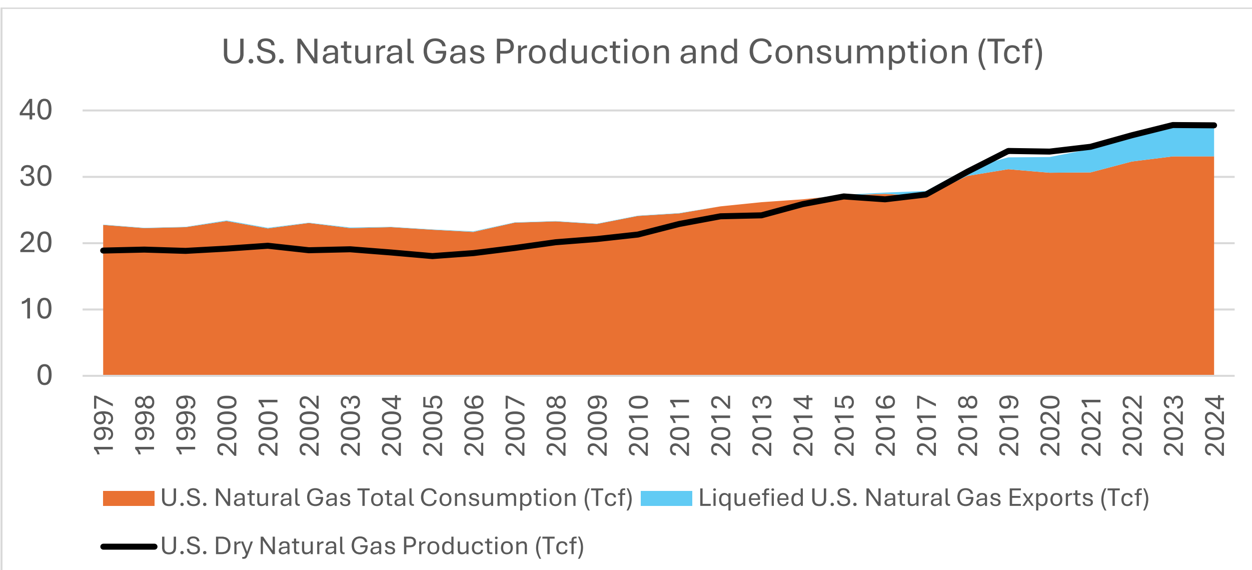
LNG Exports and Natural Gas Prices

Natural Gas Market Developments

U.S. natural gas production began increasing around 2005 after decades of stagnant production and between 2005 and 2016 natural gas production grew by 52%.[19] During that same period, the quantity of natural gas used for electricity generation increased by more than 70% and the percentage of natural gas consumed for electricity generation increased from 26.7% in 2005 to 36.4% in 2016.[20]

For decades prior to the emergence of LNG export facilities in 2016, the U.S. was a net importer of natural gas. As shown in Figure 12, since LNG exports via dedicated specialized ships began in 2016 domestic natural gas production has grown on par with LNG exports, reaching about 37.8 trillion cubic feet (Tcf) in 2024. Between 2016 and 2024, natural gas production grew 42.0% while domestic consumption grew only 20.5% and LNG exports grew 2,237%. At the end of 2024, the volume of LNG exports, reported by the EIA, were equal to 13.2% of domestic natural gas consumption.

Figure 12 - U.S. Natural Gas Production and Consumption (Tcf)



[19] EIA. U.S. Natural Gas Monthly Supply and Disposition Balance.
[20] EIA. U.S. Natural Gas Consumption by End Use.

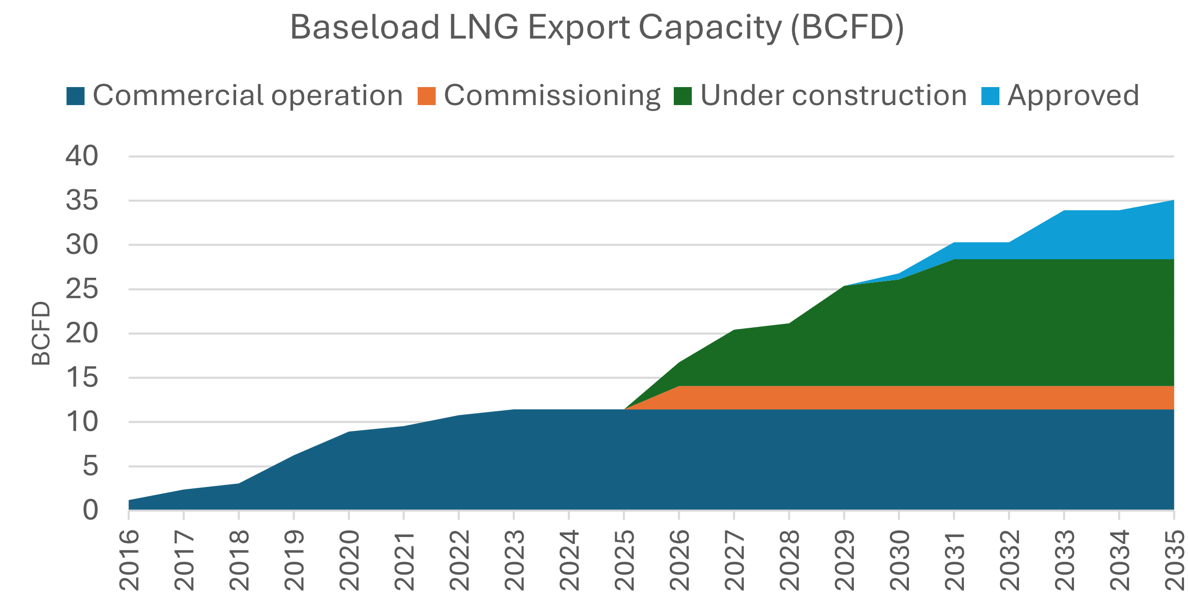
U.S. LNG Export Capacity

Individual LNG export facilities are the largest single-point demand sources in domestic natural gas markets. The average LNG export facility currently under development has a baseload capacity of over 1.59 billion cubic feet per day (BCFD) – enough natural gas energy to fuel 8.86 GW of electricity generation in combined cycle facilities if they operated at full output 24 hours a day.

Baseload LNG export capacity in the U.S. is projected to more than double by 2029, rising 122.8% from 11.4 BFCD in 2025 to nearly 25.4 BCFD in 2029 as shown in Figure 13.[21] Peak LNG export capacity, which represents the maximum potential rate of exports, is expected to increase from 14.0 BCFD in 2025 to 30.4 BCFD over the same period. According to the International Energy Agency, the U.S. represents 46.6% of global LNG export capacity expansions through 2030.[22]

[21] https://www.eia.gov/naturalgas/importsexports/liquefactioncapacity/U.S.liquefactioncapacity_2025_Q4.xlsx
[22] https://www.iea.org/data-and-statistics/charts/cumulative-lng-liquefaction-capacity-additions-from-post-fid-projects

Figure 13 - U.S. LNG Baseload Export Capacity



Data Source: EIA Liquefaction Capacity Q4 2025

In addition to the LNG export facilities represented above which have all been approved and reached a final investment decision, there are an additional 9 LNG export facilities representing an additional 5.87 BCFD of new export capacity that are fully approved[23] but have not yet reached a final investment decision[24]. Additionally, in November 2025 the Plaquemines Expansion project requested authorization for a new facility adjacent to the existing Plaquemines LNG terminal with peak LNG export capacity of 4.45 BCFD[25]. Recent federal policy changes may result in continued expansion of natural gas exports, with changes made in mid-2025 eliminating some environmental-impact reviews of applications to export natural gas to non-Free Trade Agreement (FTA) countries, particularly those related to certain types of greenhouse gas (GHG) emissions.[26]

[23] The term "fully approved" as used here includes facilities that have been approved by both DOE and FERC (for land-based) or DOT (MARAD) (for offshore).

[24] https://www.eia.gov/naturalgas/importsexports/liquefactioncapacity/U.S.liquefactioncapacity_2025_Q3.xlsx

[25] *See* FERC Energy Infrastructure Update for November 2025 at https://cms.ferc.gov/media/energy-infrastructure-update-november-2025

[26] On August 4, 2025, in *Venture Global Calcasieu Pass, LLC,* DOE/FECM Order No. 4346-B (Docket No. 15-25-LNG), DOE explained that its discussion of the 2024 LNG Export Study would focus only on the economic analysis in the Study, as well as DOE's related findings on energy security. The DOE's 2024 LNG Export Study docket page was updated to reflect these changes in October 2025.

By 2029, if the LNG export facilities currently under construction all come online, U.S. LNG exports would rise to more than 9.72 trillion cubic feet of natural gas at full utilization[27] of baseload, or nominal, export capacity. Including all approved LNG export facilities increases total exports in 2035 by 207% above 2025 levels to over 13.45 trillion cubic feet per year.

For context, LNG export volume represents under 15% of U.S. natural gas production, but export increases of this scale would require U.S. natural gas production to increase by about 20% from the current level by 2030 and by nearly 30% from the current level by 2035 to maintain the current balance between supply and demand under our estimates for LNG export volumes[28], without accounting for other increases in domestic natural gas consumption such as the rapid rise in electricity demand due to data centers.[29] The EIA's most recent forecasts in the AEO 2026 project growth in natural gas production of between 20% and 40% above 2025 levels by 2050, not including the High and Low Supply scenarios, with most of the growth in natural gas production projected to serve international markets via LNG exports.[30]

Geography of LNG Exports

Nearly all U.S. LNG exports depart from the South Central/Gulf Coast region, as shown in Figure 14.[31] However, natural gas production growth, especially future production growth, is concentrated in the eastern Appalachian region, as shown in Figure 15.[32]

[27] In 2024, LNG export facilities operated at 104% of baseload, or nominal, capacity.
[28] *See* https://www.eia.gov/outlooks/aeo/pdf/2026/AEO2026_LNGexports.pdf
[29] This growth in natural gas production only reflects growth required to meet new demand from increased LNG exports and does not include production growth necessary to meet new domestic demand such as electricity generation to support new large loads like data centers.
[30] https://www.eia.gov/todayinenergy/detail.php?id=67425
[31] https://www.eia.gov/todayinenergy/detail.php?id=64224
[32] https://www.eia.gov/todayinenergy/detail.php?id=65824

Figure 14 - U.S. LNG Export Facilities

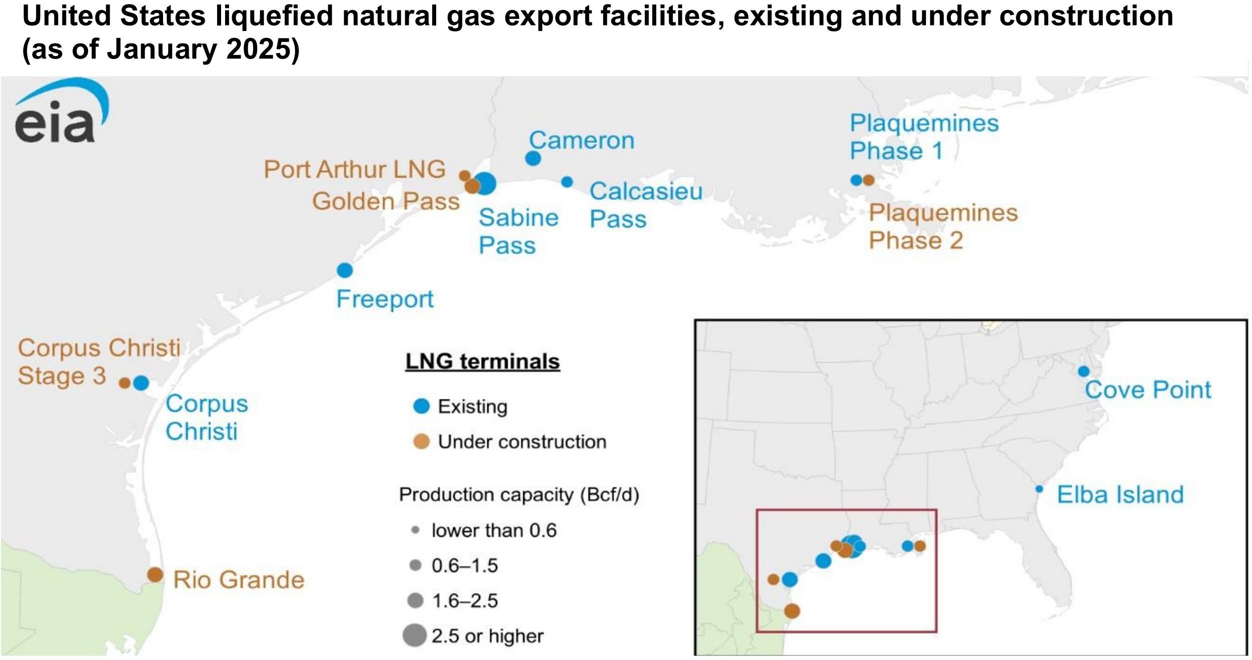
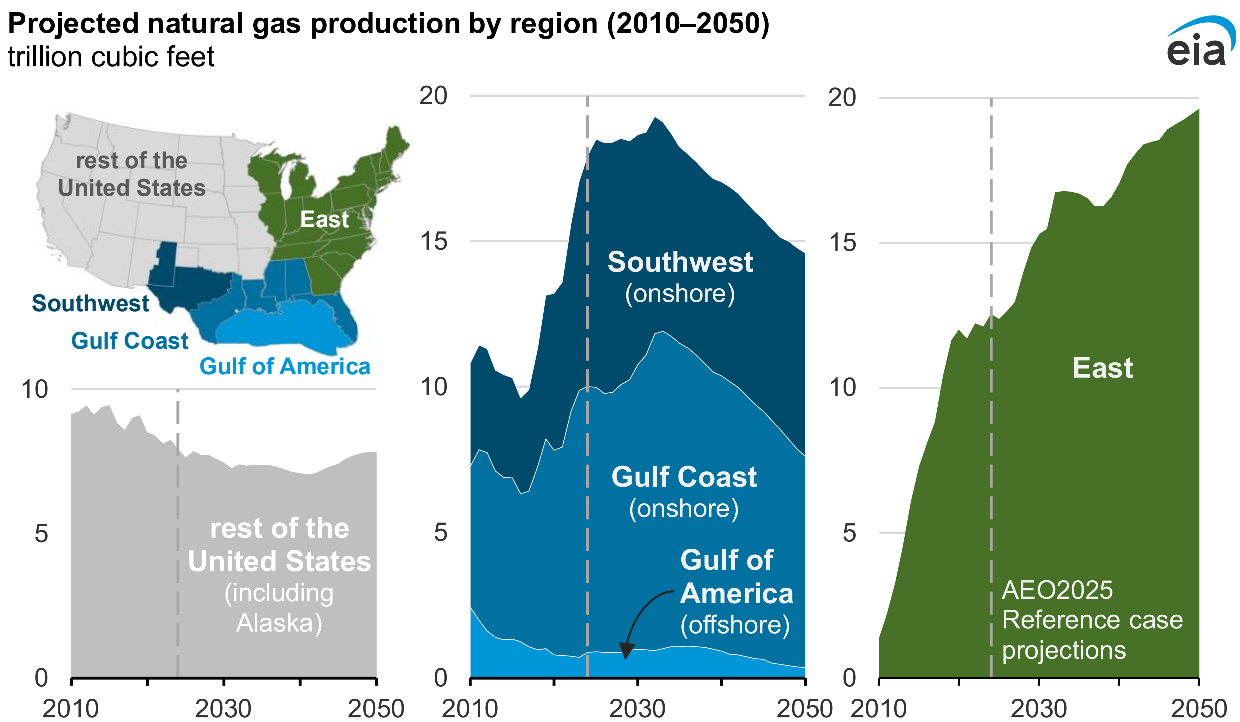
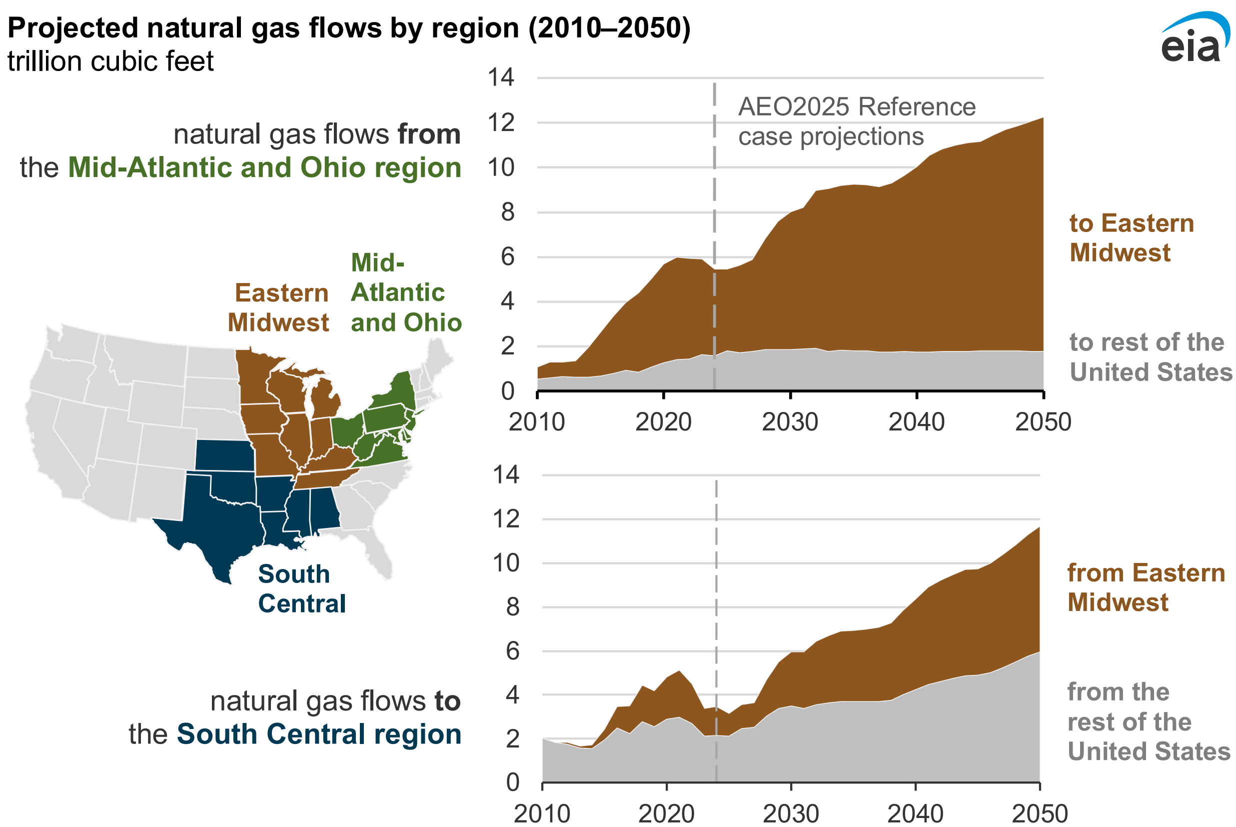


Figure 15 - Projected natural gas production by region



Since U.S. LNG exports began, natural gas flows from the mid-Atlantic to the Midwest and from the Midwest to the South Central region have increased and are projected to continue increasing, as shown in Figure 16. As intra-continental gas flows shift, gas flows from the East into the Midwest are projected to more than double by 2050 and flows from the Midwest to the South Central region are projected to nearly double by 2030 and increase nearly 400% by 2050. While these projections show the South Central region becoming ever-more dependent on pipeline capacity to import natural gas from other regions of the country, 85% of new pipeline capacity added in 2025 was within or connecting to the South Central region[33], and continued pipeline capacity development would be necessary to fully supply LNG exports and avoid adverse impacts from pipeline constraints such as higher gas prices or limited gas supplies.

Figure 16 - Projected natural gas flows by region



Natural gas prices vary in different regions of the country, at times due to local weather impacts on demand, but more generally due to the cost of extracting natural gas. "In 2024, natural gas prices averaged $0.75/MMBtu more on the Gulf Coast than in the East region, indicating that resources in the East are more economical to produce even when including the costs to transport natural gas to consumers in Texas and Louisiana on the Gulf Coast."[34]

[33] https://www.eia.gov/todayinenergy/detail.php?id=67225
[34] https://www.eia.gov/todayinenergy/detail.php?id=65824

The EIA projects this regional price difference to widen to more than $2.00/MMBTU (in 2024-denominated dollars) by 2050, and increased demand from the Gulf Coast's growing LNG export capacity will continue to be met with gas produced in lower-cost regions that is transferred to areas with higher demand and higher prices like the Gulf Coast region – a trend that impacts prices in states, such as Florida, that are dependent on Gulf Coast pipeline infrastructure.

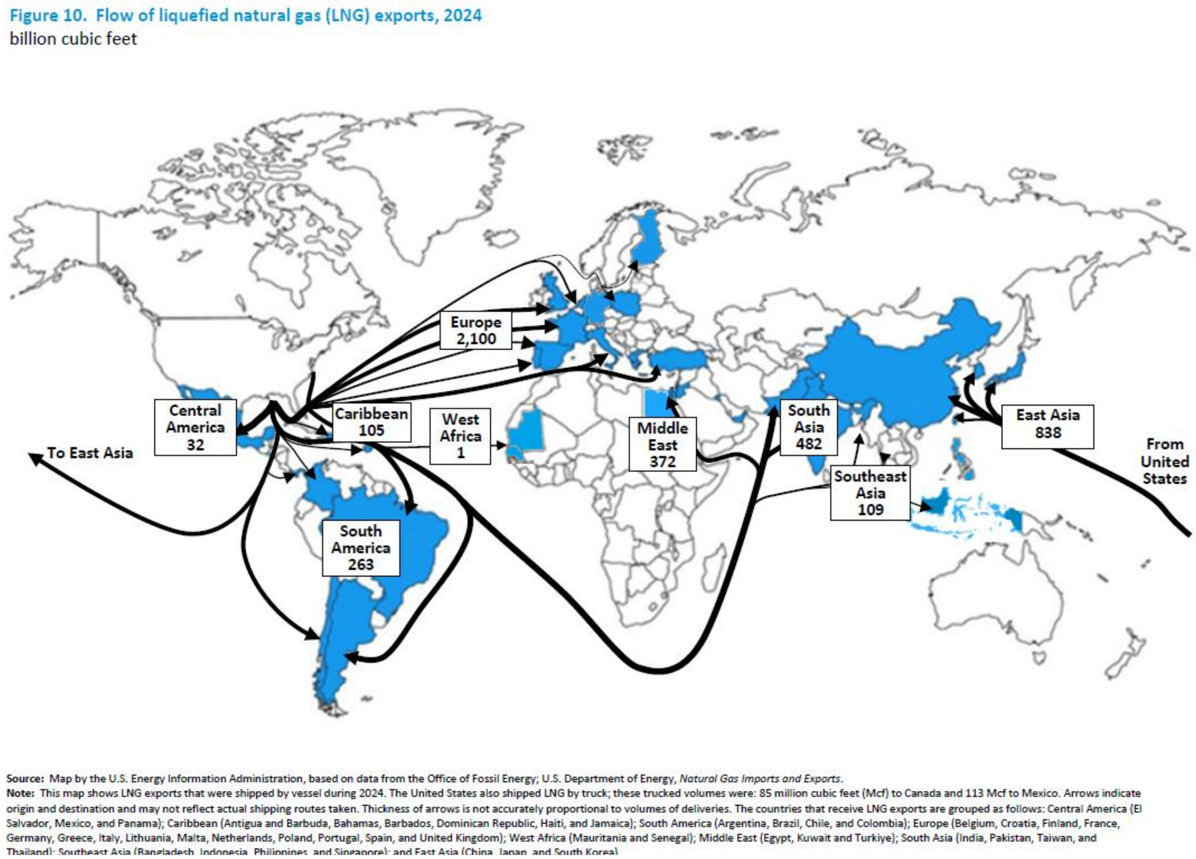
Impacts of LNG Exports on the U.S. Natural Gas Market

U.S. LNG exports have risen rapidly and steadily since they began in 2016, and at 11.9 BCFD of LNG exports in 2024, the U.S. remained the leading global exporter of LNG followed closely by Australia and Qatar with 10.2 and 10.7 BCFD exported.[35] In 2024, the U.S. exported 4.37 trillion cubic feet of LNG – a 140.0% increase over 2019 LNG exports.[36] The value of U.S. LNG exports in 2024 was $27.99 billion.[37]

The average price of LNG exports in 2024 of $6.41 per thousand cubic feet (MCF) was nearly three times the average Henry Hub spot price of $2.19. This price premium is partly due to the use of natural gas to fuel the energy-intensive process of liquifying natural gas, but it is easily offset because LNG exporters ultimately are paid for LNG at a price based on foreign-market natural gas prices, typically set based on prices in Asian or European markets which are the destination for the majority of U.S. LNG exports, as shown in Figure 17.

[35] https://www.eia.gov/todayinenergy/detail.php?id=64844
[36] https://www.eia.gov/dnav/ng/ng_move_poe2_a_EPG0_ENG_Mmcf_a.htm
[37] https://www.eia.gov/dnav/ng/ng_move_poe2_a_EPG0_PNG_DpMcf_a.htm

Figure 17 - LNG Export flows



LNG Market Dynamics

LNG exports are increasingly made under long-term (i.e., 10 or more years) sale-and-purchase agreements (SPAs) with 75% of global export volume subject to such agreements since 2022.[38] After a few years of declines in new SPAs – a necessary step for new LNG export facilities to reach a final investment decision – new SPAs for 5.2 BCFD of LNG exports were executed during 2025.[39] Over 90% of LNG export volumes in 2025 were contracted as free-on-board SPAs, under which international buyers take ownership of and pay for the purchased LNG exports at the producing country's loading terminal.

About 80% of U.S. LNG export terminal capacity not only use SPAs, but also increasingly feature destination-free agreements, which allow the contracted buyer of U.S. exports to deliver the LNG to any allowable import market globally.[40] In 2025, about 56% of SPAs had a purchase price indexed to the Henry Hub price, and 95% were contracted for 20 or more years.

---

[38] IEA. Gas 2025. https://iea.blob.core.windows.net/assets/db3d568d-b985-4cc2-bb1a-119517f118ac/Gas2025.pdf
[39] https://www.eia.gov/todayinenergy/detail.php?id=67264
[40] EIA. Natural Gas Weekly Update. Week of January 25, 2023. https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2023/01_26/#itn-tabs-0

The combination of long-term guaranteed LNG supply agreements, destination-market flexibility, and pricing structures that reduce LNG export sensitivity to domestic market prices positions LNG exports as a market segment with baseload-type demand. LNG exports effectively represent an increasingly large block of fixed demand with volumes that do not respond to changes in U.S. natural gas prices like most other natural gas consumers. For U.S. consumers, the impact of these LNG market dynamics is a likely increase in price volatility due to a) how LNG export demand will amplify any short-term supply shortfalls and b) the potential for more consistent growth in natural gas production, as the steady nature of this increased demand reduces the risk to suppliers of prices falling below their cost of production.

Sale and Purchase Agreements

SPAs often feature terms commonly characterized as "take-or-pay" under which the buyer agrees to accept a minimum quantity of LNG over a set period such as a year or pay an agreed-upon amount, potentially up to the full amount of contracted volume at the contracted price, and retain the right to take delivery of the unfulfilled contract volume at a later date.

Although the individual terms of a particular SPA vary somewhat, the general take-or-pay concept provides a degree of certainty to both the buyer, or importer, and the seller, or exporter – certainty as to both volume and price.[41] The significant investments required to support LNG export (e.g., liquefication) and import (e.g., LNG storage, re-gasification, and end-use development such as distribution pipelines or power generation facilities) benefit from the certainty and reduced risk provided by such long-term contracts.

Within the U.S. natural gas market, these types of SPA clauses present an additional source of potential price volatility. In 2024, LNG exports represented about 11% of the 37,767 BCF of dry natural gas production in the U.S.[42] Although the fixed nature of SPAs limits the direct influence of higher-priced global natural gas markets on domestic prices, the increasingly large share of U.S. production volume tied up in LNG SPAs magnifies the price swings that result from supply-demand imbalances in the U.S. natural gas market, much the same way using a lever and fulcrum magnifies force.

LNG's leverage effect can amplify domestic price movements upward or downward, depending on the nature of the supply disruption. For instance, the failure of piping at the Freeport LNG Terminal on June 8, 2022, resulted in an explosion and fire that shuttered the entire facility until January 2023.[43] This incident reduced U.S. LNG export capacity by about 2 BCFD, a reduction of nearly 20% of then-total U.S. LNG export capacity.

[41] https://www.jdsupra.com/legalnews/the-shift-away-from-take-or-pay-42077/
[42] https://www.eia.gov/dnav/ng/hist/n9070us2m.htm
[43] https://www.ferc.gov/industries-data/resources/project-directory/freeport-lng-incident-june-2022

Henry Hub spot prices on the day of the event averaged $9.43/MMBTU but fell 18.1% to $7.72/MMBTU within a week and while the outage persisted Henry Hub spot prices trended dramatically downward as a result of the oversupply of natural gas in the U.S. market, falling to below $3/MMBTU – the lowest levels since mid-2020.[44] Likewise, imbalances resulting from increased demand during extreme hot or cold weather will likely see higher price spikes because the LNG export portion of natural gas demand is less responsive to prices than other market segments. In other words, domestic gas supply will be even more constrained because LNG exporters will still be filling their orders, thereby driving domestic gas prices higher.

Global Market Exposure

Destination-flexible LNG contract marketing allows SPA buyers the opportunity to ship LNG to destinations besides the primary contracted import destination. Destination-flexible contracts are also increasingly used by "portfolio players" that serve as global LNG brokers providing purchase or sale guarantees for export volumes while retaining the flexibility to adjust LNG destinations according to variations in global market demand. According to the International Energy Agency, portfolio players' procurement volume in 2025 reached 42% of total LNG contracts, up from 26% in 2016, increasing global LNG market liquidity substantially.[45]

Another emerging trend in the globalization of U.S. natural gas markets via LNG exports are instances of small-scale indexed-price SPAs. Under these agreements, U.S. gas producers contract for the sale of domestically produced gas at a price based on foreign-market price indexes. Starting in 2027 and 2028, at least three such contracts for a total of more than 100 BCF per year are expected to begin.[46] Although they represent experimental-scale activity at present, such direct-to-consumer type contracts bypass U.S. market prices as gas production at the wellhead is exclusively for export, reducing domestic supply and could result in upward pressure on domestic gas prices if implemented on a larger commercial scale.

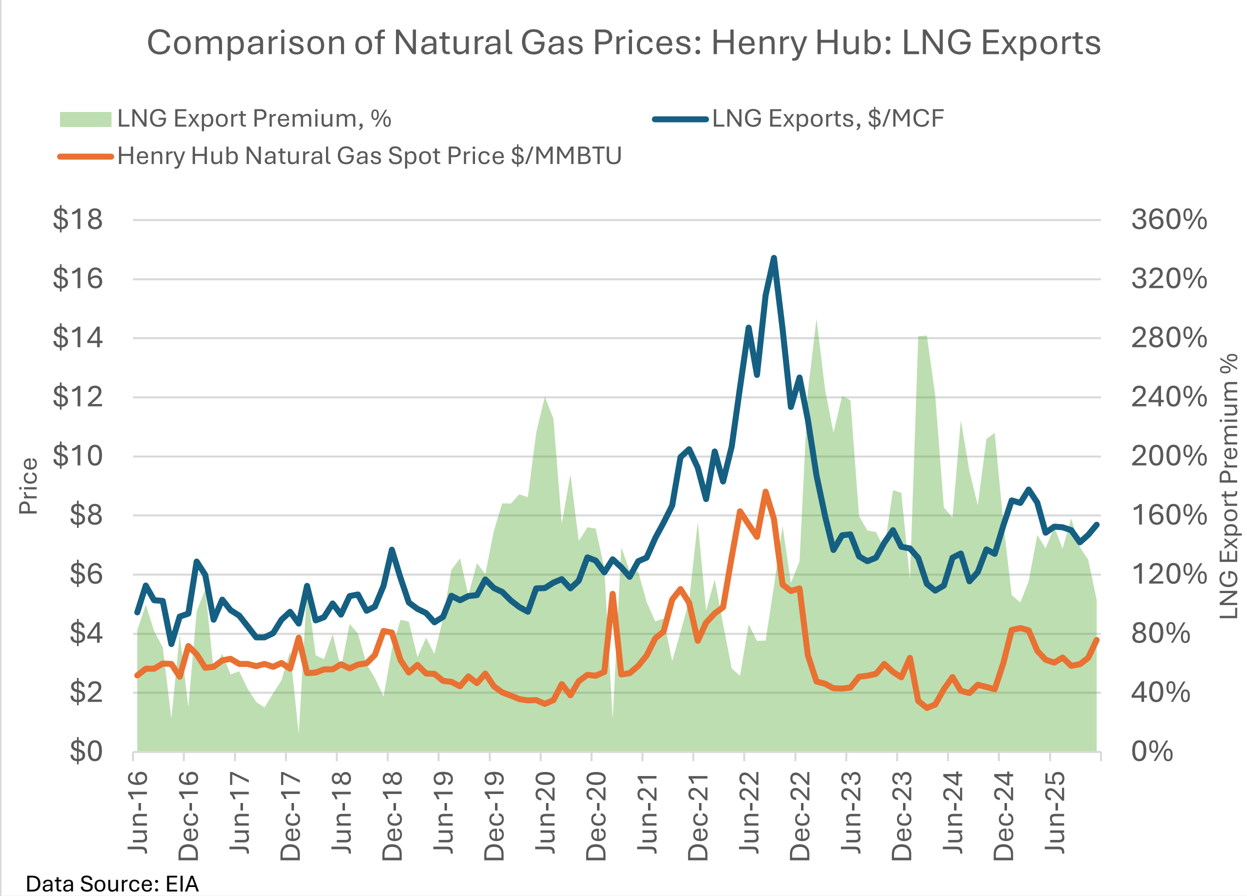
[44] https://www.eia.gov/dnav/ng/hist/rngwhhdD.htm
[45] IEA. Gas 2025. https://iea.blob.core.windows.net/assets/db3d568d-b985-4cc2-bb1a-119517f118ac/Gas2025.pdf
[46] https://www.hartenergy.com/exclusives/chesapeake-lng-deal-moves-its-haynesville-gas-closer-global-price-204389/ and https://www.lw.com/en/news/latham-watkins-advises-vitol-in-long-term-lng-indexed-gas-supply-agreement and https://naturalgasintel.com/news/global-lng-marketers-tout-natural-gas-supply-deals-with-us-producer-coterra/

LNG Export Impacts on Natural Gas Prices & Risks

LNG exports occupy a novel and increasingly large niche in the U.S. natural gas market, and the potential impacts on natural gas prices and price risks to U.S. consumers is not well understood. The limited understanding of LNG export risks to U.S. consumers results from (1) limited data[47] on how LNG exports influence U.S. natural gas markets, (2) the recent rapid growth of LNG exports[48], (3) uncertainty about the future degree of LNG export growth, and (4) the complexity of natural gas markets themselves.

LNG exports are sold at a premium relative to U.S. natural gas prices because they supply the global market where natural gas prices are higher. Figure 18 shows this export price premium in the green area as a percentage of domestic prices on the right axis, with actual prices as lines.

Figure 18 - Comparison of Natural Gas Market Price and LNG Export Price



[47] There have been less than 10 years of large-volume dedicated tanker ship-based LNG exports, and LNG exports have only exceeded 10% of U.S. natural gas consumption in the most recent four of those years. Further complicating analyses is the impact of the COVID-19 response in 2020 and 2021 which affected all energy demand in the U.S. and globally.

[48] LNG exports increased 479.7% in their first three years of dedicated tanker ship-based exports (i.e., between 2016 and 2018), and then 301% between 2018 and 2023.

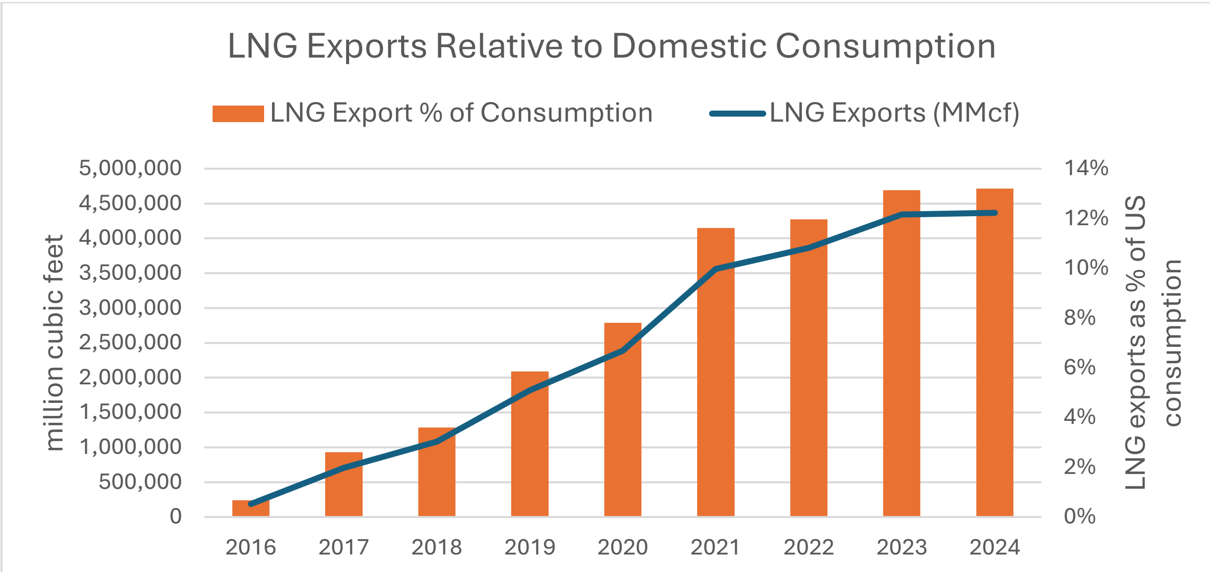
Because LNG exports also represent an increasingly large share of natural gas demand that is far less responsive to domestic influences on natural gas prices, U.S. prices would have to rise to a level that is competitive with prices in foreign LNG import markets for domestic consumers to secure supply that otherwise would have been exported. For comparison, natural gas prices in Asia in January 2026 were about $10.44/MMBtu[49] and prices in the European Union were about $12/MMBtu[50], compared to about $4/MMBtu in the U.S.[51] This premium is magnified during times of global supply disruptions such as the 2022 invasion of Ukraine when prices reached about $70/MMBtu and $54/MMBtu in the EU and Asia, respectively, while domestic prices remained under $10/MMBtu.

To the extent that U.S. natural gas production can match the growth rate of both LNG exports and domestic consumption – and maintain that level of production – the long-term impacts on domestic prices are likely to be minimized. However, if the demand from LNG exports outpaces domestic supply or otherwise results in supply-demand imbalances, whether short-term or long-term imbalances, LNG exports are likely to result in increased natural gas prices and increased price volatility for U.S. consumers.

LNG exports are a rapidly growing and increasingly important market for domestic natural gas. As shown in Figure 19, LNG exports have increased from a negligible percentage to the equivalent of about 13.2% of domestic natural gas consumption in less than a decade, and LNG exports are projected to double[52] before the end of the decade to reach between 25% and 30% of domestic consumption. To minimize the impact on domestic natural gas prices, the rapid and substantial increase in natural gas demand from LNG exports would require not only increasing domestic production to satisfy this new demand but also maintaining those higher levels of production for decades to come.

[49] https://fred.stlouisfed.org/series/PNGASJPUSDM
[50] https://fred.stlouisfed.org/series/PNGASEUUSDM
[51] https://www.eia.gov/naturalgas/weekly/ week ending January 21, 2026.
[52] https://www.eia.gov/todayinenergy/detail.php?id=66384

Figure 19 - LNG Exports Relative to Domestic Consumption



LNG Export Impact Studies

Higher demand from LNG export facilities is generally expected to increase natural gas prices over the coming decades. The U.S. Department of Energy's 2024 LNG Export study[53] (DOE Study) examined potential impacts on the Henry Hub price from a 150% increase in authorized export volumes by 2050.

The DOE Study's Reference scenario resulted in an additional $1.09/MMBTU Henry Hub price increase (i.e., from $3.53/MMBTU to $4.62/MMBTU), with a low-end increase of $0.94/MMBTU for a high gas production/supply scenario and an upper price increase of $2.30/MMBTU for a low gas production scenario.

[53] https://www.energy.gov/sites/default/files/2025-10/ENERGY%2C%20ECONOMIC%2C%20AND%20ENVIRONMENTAL%20ASSESSMENT%20OF%20U.S.%20LNG%20EXPORTS_0.pdf

However, there are a few caveats worth noting to the DOE Study. The first is that all scenarios for the above-referenced prices include declining natural gas consumption in the U.S. electric power sector by 2050 of between -7.4% and -17.4%, and minimal growth in overall domestic natural gas consumption. Second, the DOE Study does not reflect current federal policies with regard to renewable energy such as solar or wind which typically offset natural gas generation, or the then-enacted limits on GHG emissions from new natural gas facilities that will not likely remain in effect. Additionally, recent federal policy changes remove some of the GHG emissions evaluations related to consideration of LNG export applications, potentially enabling more exports or faster growth in exports than those included in the DOE Study. Finally, the DOE Study was completed before the current cycle of rapidly expanding demand for new power generation, including new natural gas generation, to power AI and related data centers was fully recognized.

The same DOE Study noted that the EIA's AEO 2023 produced a range of Henry Hub spot prices (in 2022 dollars) from $2.78/MMBtu to $6.37/MMBtu in 2050. The EIA forecast from the AEO 2025 was published in early 2025[54], relies on 2024 data, and is also subject to the same policy and demand caveats as the DOE Study.

The AEO 2026[55] projects an annual domestic gas production growth rate between 2025 and 2050 from 2.0% under a high supply scenario to -1.1% under a low supply scenario. The AEO 2026's baseline, high-, and low-supply scenarios all project net LNG exports through 2050. Henry Hub prices (in 2025$) forecast for 2050 in the AEO 2026 are $4.64/MMBtu under the baseline scenario, $2.75/MMBtu under the high-supply scenario, and up to $13.67/MMBtu under a low-supply scenario. While the 2050 price projections for the baseline and high-supply scenario in AEO 2026 are relatively unchanged from AEO 2025, projected 2050 prices under the low-supply scenario are 40.2% higher in AEO 2026 than in AEO 2025.

---

[54] The AEO 2025 was prepared after the EIA updated the National Energy Modeling System which is used to produce the AEO. Although the extensive model development conducted in 2024 better reflects a variety of recent trends, the AEO 2025 does not include significant recent changes in federal policy or changes in market developments such as data center-driven load growth. For more information on the updates, see https://www.eia.gov/outlooks/aeo/resources/.

[55] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2026&region=0-0&cases=cb2026~highogs~lowogs&start=2025&end=2050&f=A&linechart=~~&sourcekey=0

The 2025 Edition of BP's annual Energy Outlook[56] shows LNG exports continuing to rise alongside overall global natural gas demand through 2050 if maintained on the current trajectory, and eventually decreasing by 2050 after increasing through at least 2035 if policies are enacted globally to limit the impact of GHG emissions to a 2°C global average temperature change. The World Bank's 2025 Commodity Markets Outlook[57], published in April 2025, projected U.S. natural gas prices to increase by about 50% in 2025 as the price gap between U.S. prices and global prices starts to narrow – a projection that turned out to be close to the actual 56% increase in average daily Henry Hub spot market natural gas price.

Analysis of LNG Export Impacts on U.S. Natural Gas Prices

LNG exports are 1) a source of significant new and rapidly growing natural gas demand that is largely insensitive to domestic prices, and 2) a long-term fundamental driver of natural gas demand that could represent one-third or more of domestic natural gas production at current production levels. The impact LNG exports will have on natural gas prices depends on multiple factors, including:

- Supply-Demand Balance: The extent to which natural gas production can grow in parity with demand and sustain production levels over time;
- LNG Export Contract Terms: The extent to which LNG export volumes are responsive to domestic natural gas prices and the duration of contracted export volumes;
- Timing and Coincidence of New Export Facility Commercial Operation Dates: The total volume of new LNG export demand coming online when expected and the new demand volume entering the market over a short time period.

A single LNG export facility with a baseline export capacity of 1 BCFD would export between 0.36 and 0.38 trillion cubic feet (Tcf) per year, or about 1.1% of total annual U.S. natural gas production. Known LNG export facilities with export approval represent between 30% and 45% of AEO 2026 scenarios' projected U.S. dry natural gas production as early as 2037. These facilities commonly operate under contracts with fixed-price or minimum-volume terms for periods of 10 or 20 years, making this large share of demand largely unresponsive to domestic market price signals.

Natural gas price risk manifests in two primary ways:

[56] https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2025.pdf
[57] https://thedocs.worldbank.org/en/doc/1b388949805c9a0ae3736bdacb32ea94-0050012025/original/CMO-April-2025.pdf

- Price Volatility: The degree of daily price movement relative to a longer-term average price, where higher volatility reflects higher price risk, based on standard deviation of price movement;[58] and
- Absolute Price Level: The extent to which sustained higher levels of demand results in sustained higher prices as the lowest-cost natural gas is extracted before higher-cost natural gas and higher prices are necessary to drive investment in higher-cost natural gas resources.

This analysis begins by adjusting AEO 2026 forecasted LNG export volume to reflect recent developments in LNG export permits and to incorporate exports not included in the EIA forecast. The impacts of this increased volume are represented based on the two price risk mechanisms described above, with the mechanisms represented independently.[59] Price volatility is represented by changes in the annual standard deviation of natural gas prices based on the annual percentage change in LNG exports. Changes in the absolute price level of natural gas are projected based on the volume of LNG exports as a percentage of forecasted natural gas production.

LNG Export Impacts on Absolute Price Level

Sustained large increases in demand, such as those from increased LNG exports, require (1) increased natural gas extraction and production, as well as (2) a replacement rate for natural gas wells, particularly for shale resources, to maintain the balance between supply and demand. However, assuming a reasonable level of economic efficiency in the extraction industry, lower-cost resources will be drawn upon first and as additional resources enter the supply the cost of extracting those resources increases, requiring a higher market price to justify the investment.

This economic merit order effect is the underlying driver of increases in the absolute price level of natural gas as LNG exports claim an increasingly large share of domestic natural gas production. This effect is compounded by the contractual nature of LNG exports, which includes long-term contracted volumes and often pricing that is somewhat unlinked from domestic markets.

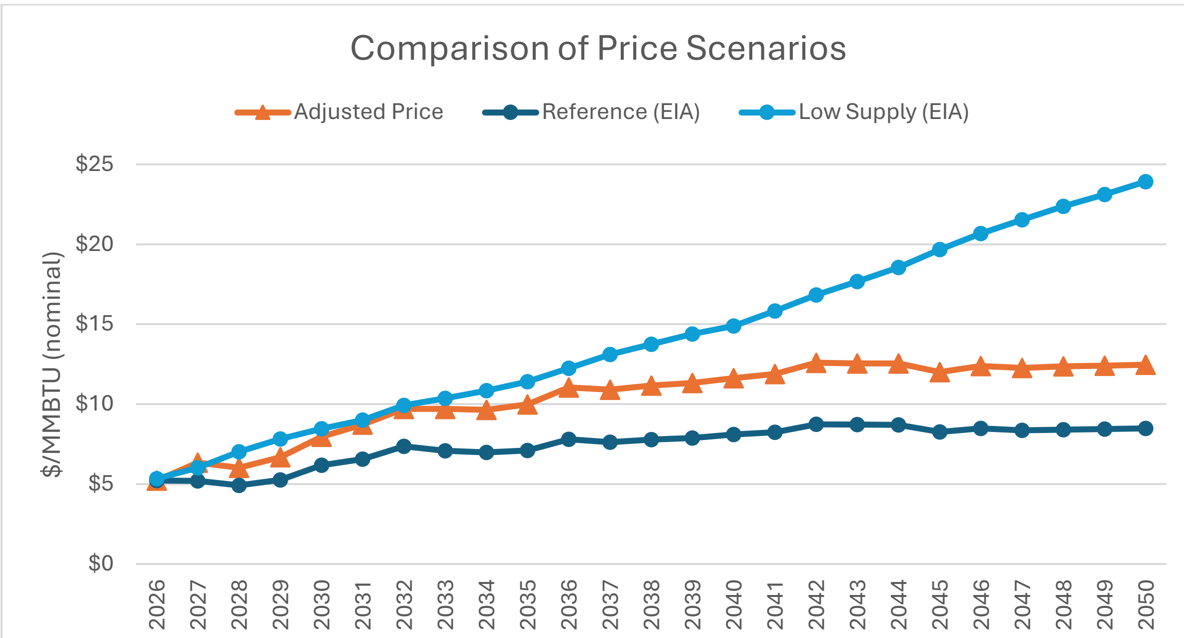
---

[58] *See* https://www.eia.gov/todayinenergy/detail.php?id=65784#:~:text=The%20average%20historical%20volatility%20of,69%25%20by%20mid%2D2025 and https://www.eia.gov/todayinenergy/detail.php?id=53579

[59] Sustained changes in the absolute price level are typically driven by fundamental shifts in the balance of supply and demand such as new extraction technology, development of new markets, etc. Price volatility occurs over shorter periods of time in response to recent events such as weather, geopolitical instability, or even industrial accidents. Elevated price volatility can increase the average price over a period of time such as a season or year, and higher price volatility also increases uncertainty and price instability in household heating and electric bills.

The results of our analysis of LNG impacts on the absolute price level of U.S. natural gas reflect the increased demand of LNG exports. Figure 20 shows an Adjusted Price scenario that is based on LNG export volumes increasing share of U.S. natural gas production. The results project expected growth in LNG exports to increase domestic natural gas prices by 28.8% in 2030 relative to the EIA's Reference scenario which rises to an increase of 46.9% by 2050 relative to the EIA's Reference scenario.

Figure 20 - Comparison of Price Scenarios



LNG Export Impacts on Price Volatility

The second part of natural gas price risk is the extent of short-term price movements, or volatility. Volatility measures price movements over a specified time period and it is typically based on the standard deviation[60] of price movements.[61] Because our analysis is forward-looking and constrained by available forecast data – EIA's AEO does not include volatility forecasts, standard deviations, or intra-year price movements – standard deviations and the relative standard deviation[62] (RSD) are used to represent this aspect of natural gas price risk.[63]

Figure 21 shows the comparison of standard deviation by year for the EIA's Reference scenario and our calculated Adjusted scenario. The start of commercial operations at new LNG export facilities is likely to increase price volatility over the short term because each new facility is a significant new source of natural gas demand.

---

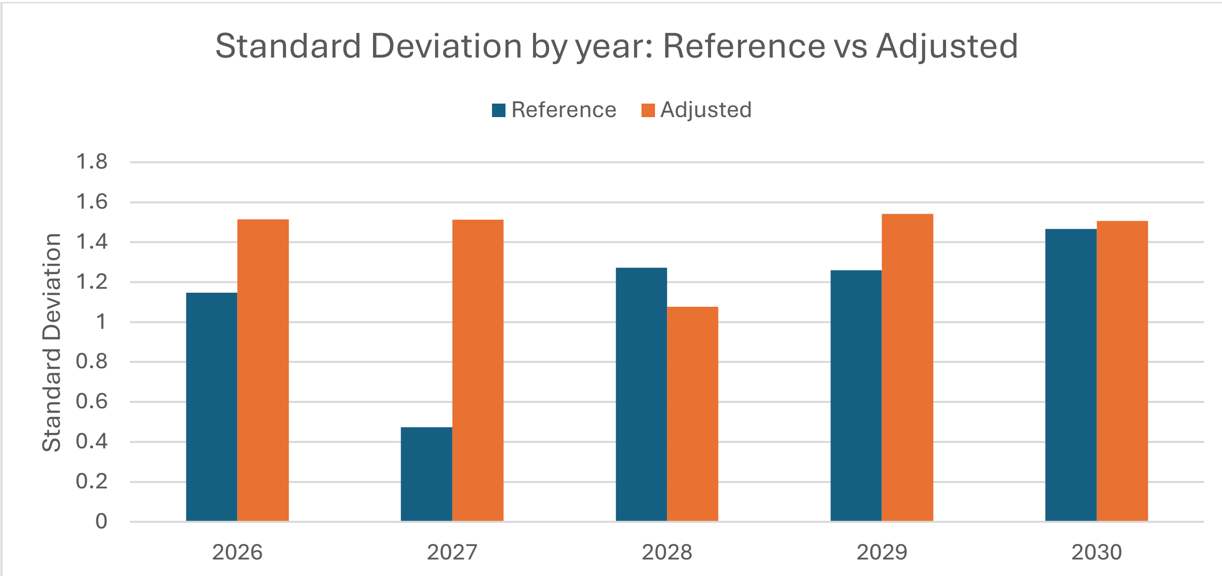
[60] Standard deviation measures the dispersion of data points relative to their average; low values indicate data is close to the average, while high values indicate values further from the average.

[61] *See* https://www.macroption.com/implied-vs-realized-vs-historical-volatility/, https://www.eia.gov/todayinenergy/detail.php?id=53579, and https://www.eia.gov/todayinenergy/detail.php?id=65784

[62] Relative Standard Deviation, or the Coefficient of Variation, is the ratio of the standard deviation to the average (i.e., mean). Use of the RSD allows comparison of variation over multiple years with different average prices. A high RSD indicates there is a lot of variability in the data, or that values in the data set are widely dispersed compared to the average. For more information on RSD, see https://www.6sigma.us/six-sigma-in-focus/relative-standard-deviation/.

[63] Because the average natural gas price changes from year to year, a comparison of standard deviations from year to year can be misleading. For example, a year with an average price of $3/MMBtu and a standard deviation of 0.30 means that each standard deviation represents a price that is +/- $0.30/MMBtu, with an RSD of 0.1, but a year with an average price of $5/MMBtu and a standard deviation of 0.30 means that each standard deviation represents a price that is +/- $0.30/MMBtu, with an RSD of 0.06. In this example, the standard deviation is the same in both years and does not fully represent price volatility, but the lower RSD in the latter year indicates a reduction in price volatility or a reduction in the dispersal of prices around the average price.

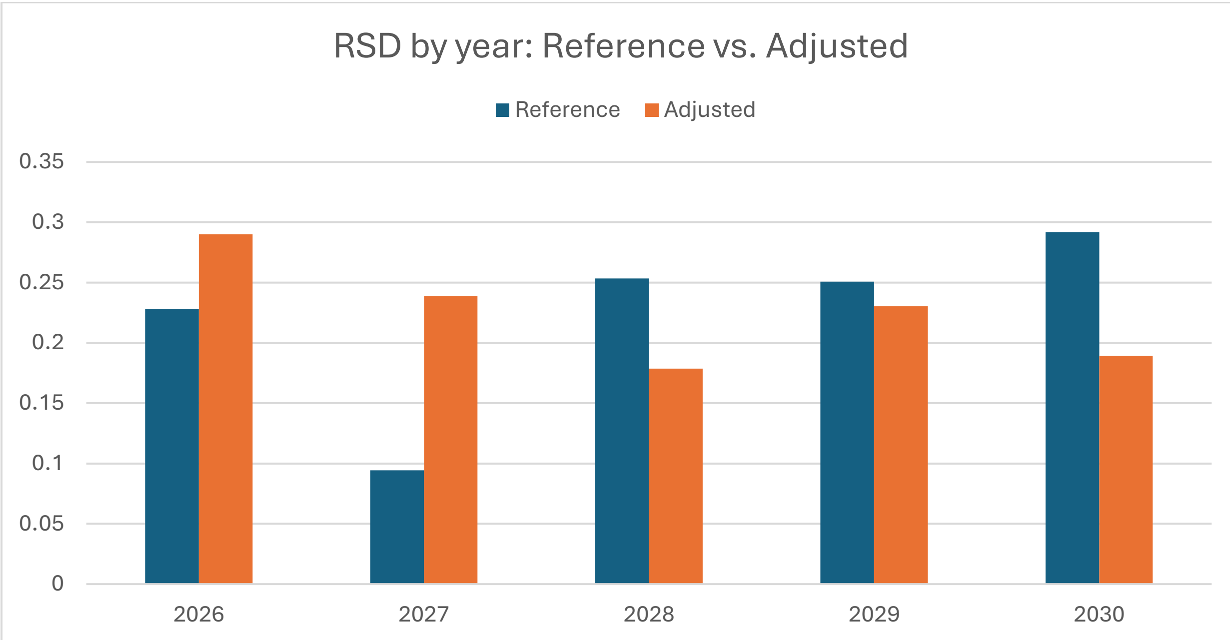
Figure 21 - Comparison of Standard Deviation by year



Because the AEO does not include standard deviation forecasts for natural gas prices, we relied on an analysis of daily historical Henry Hub spot market prices to first calculate historical annual standard deviations of natural gas prices and price movements. To calculate standard deviations for forecast years, we apply the historical relationship between increases in LNG exports and increases in natural gas price volatility to future year prices based on the timing of expected increases in LNG exports.

As shown in Figure 22, the RSD varies considerably from year to year based on the timing of new LNG export facilities starting operations. Because of their large volume of demand, when new LNG export facilities start operating there is some degree of market disruption that can be magnified depending on the extent to which the actual start date occurs as expected or whether it is later or earlier than expected.

Figure 22 - RSD by year

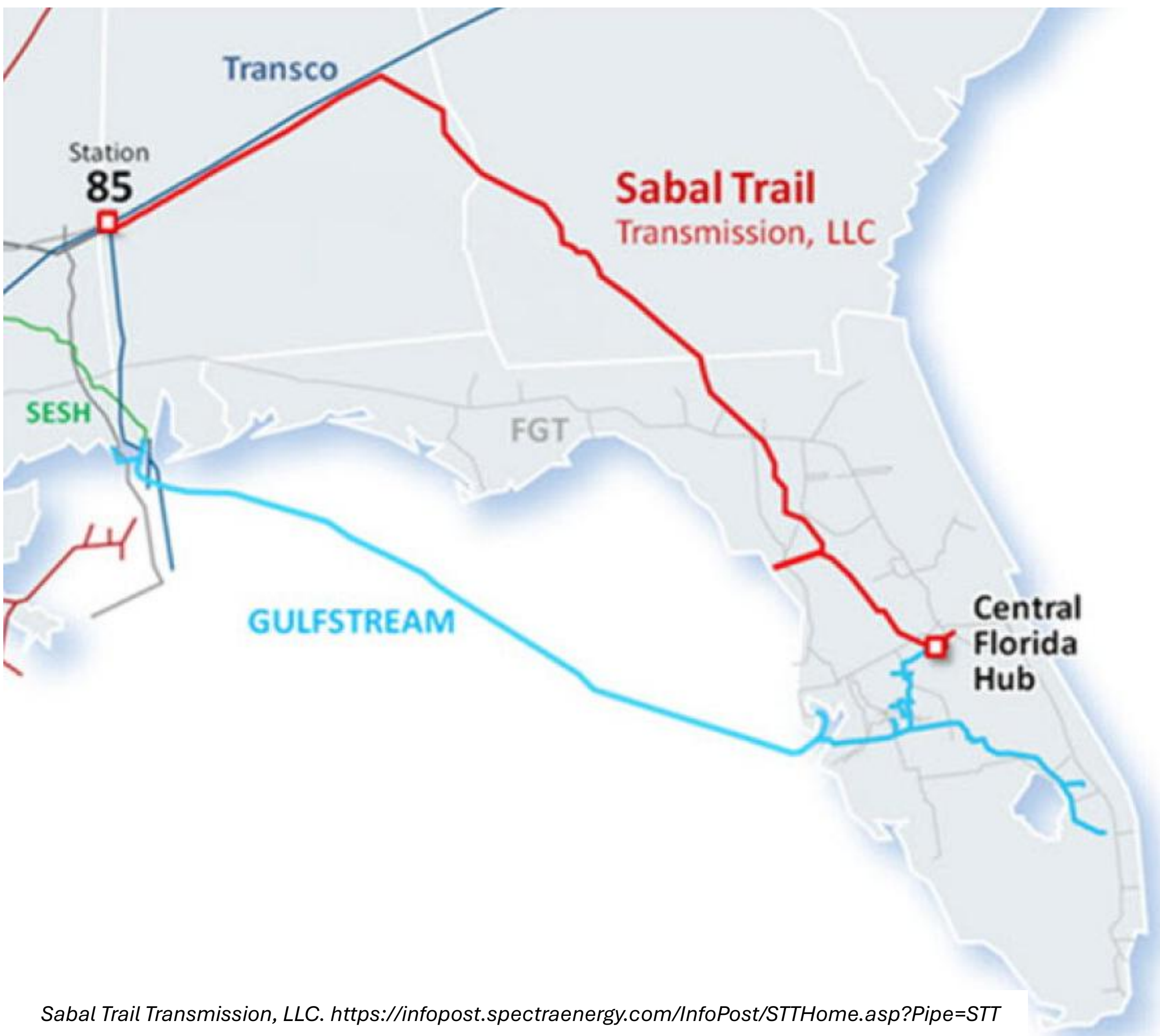


Analysis of LNG Export Impacts on Florida Electricity Consumers

Key Risk Factors for Florida Electricity Consumers

Florida's natural gas supply is delivered through three interstate pipelines, shown in Figure 23, all of which originate from the Henry Hub pipeline network in Louisiana. The geographic concentration of natural gas supplies increases the state's vulnerability to disruptions in the South Central pipeline network as the state's entire gas supply could be disrupted by a single event.

Figure 23 - Pipelines supplying Florida natural gas



Sabal Trail Transmission, LLC. https://infopost.spectraenergy.com/InfoPost/STTHome.asp?Pipe=STT

This geographic risk is compounded by Florida's high degree of reliance on natural gas for electricity generation. Any event that significantly disrupts natural gas supplies in the South Central region would have significant impacts on the availability of electricity in the state, and similarly, developments that increase natural gas prices in the South Central region would also increase prices of natural gas and therefore prices of electricity for Florida consumers.

Florida shares its dependence on this pipeline network with other southeastern Atlantic states. In addition to rapid growth in LNG exports, domestic demand for natural gas is also growing rapidly in states connected to the South Central pipeline network, particularly new natural gas electricity generation to support data centers and other large loads in Virginia, Georgia, Texas, and North Carolina. The rapid domestic growth in natural gas demand and growth in LNG exports have compounding effects on the price and availability of natural gas because of their shared dependence on the South Central pipeline network.

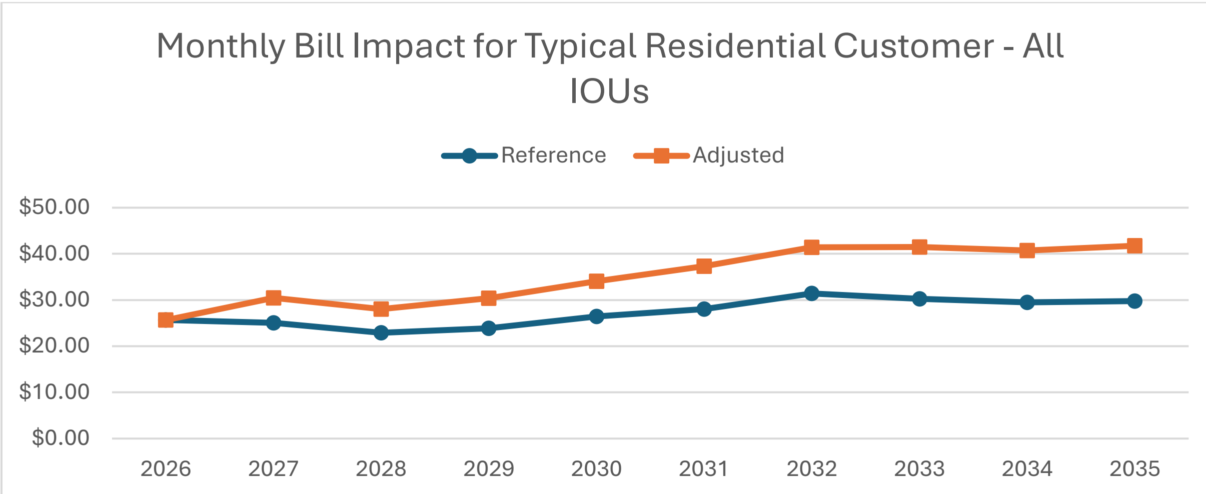
Scenario Analysis

To examine the impact of LNG exports on Florida electricity consumers, the adjusted natural gas price forecasts described in the previous chapter are applied to the Florida IOUs' Ten-Year Site Plans using the same methodology[64] in the Phase 1 study. This new scenario based on LNG export-adjusted prices is then compared with the AEO Reference case scenario for the years 2026-2035.

For all Florida IOUs combined, by 2035 the EIA's Reference case projects a $4.10 increase in the typical residential monthly electric bill, but the monthly bill increase is $16.10 when the effects of LNG export growth are included. Overall, LNG exports are projected to increase typical residential electricity bills in Florida by nearly 300% more than the increase projected under the EIA's Reference scenario, as shown in Figure 24. By 2035, natural gas costs on the typical residential monthly electric bill under the Reference scenario rise by $4.10 to $29.76, whereas under the LNG export Adjusted scenario natural gas costs on the typical residential monthly electric bill rise by $16.10 to $41.76. Overall, for the combined IOUs, LNG export growth is projected to result in a cumulative increase in fuel costs of $18.48 billion to Florida electricity consumers between 2026 and 2035 compared to the Reference scenario.

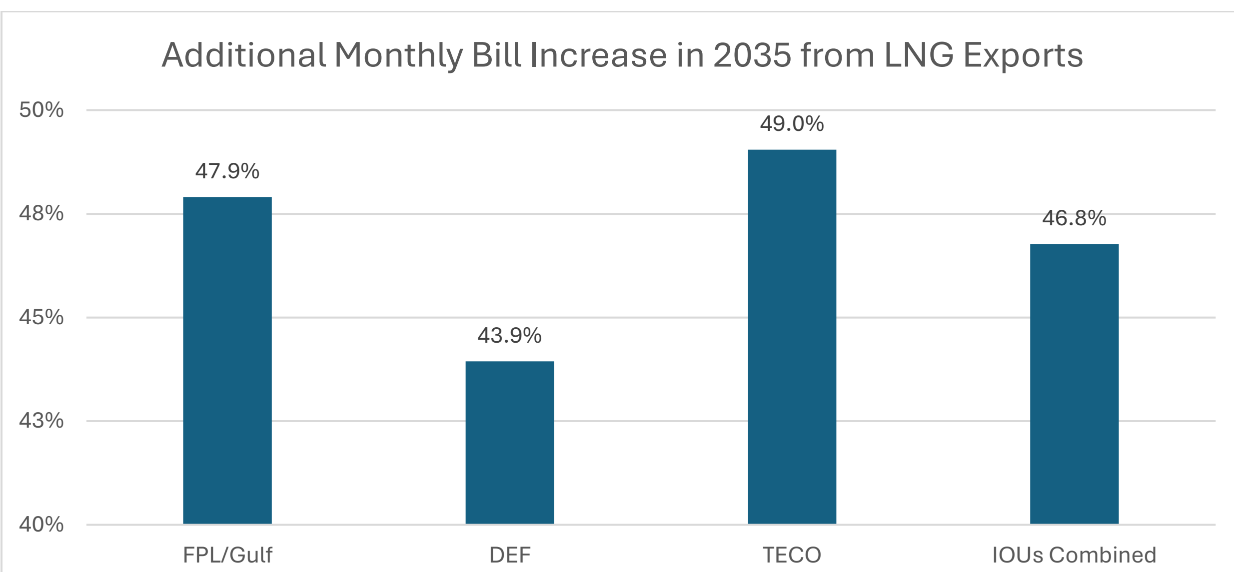
[64] This study uses nominal dollars instead of real 2025-denominated dollars in an effort to convey the actual forecast prices consumers will pay in the year they will pay them.

Figure 24 - LNG Export Residential Monthly Bill Impact - All IOUs



Our analysis indicates expected growth in LNG exports will result in monthly residential electric bills that are substantially higher by 2035 than they would be under the EIA's Reference scenario. As shown in Figure 25, LNG exports are projected to add 46.8% to the forecasted increase in monthly residential electric bills for all Florida IOUs combined. For example, under the EIA's Reference scenario prices, the natural gas portion of a typical residential bill for all IOUs combined increases by 16%, but under the LNG export growth-Adjusted prices the natural gas portion of a typical residential bill for all IOUs combined increases by 62.8%, which is an additional increase of 46.8%.

Figure 25 - Additional monthly residential bill increase from LNG exports



Among the individual IOUs, the largest dollar increase occurs for TECO customers as monthly electric bills increase $21.79/month by 2035 under the LNG export-adjusted scenario compared to only $6.67 under the Reference scenario. DEF customers are expected to see a bill increase by 2035 of $2.78 under the Reference scenario prices, but an increase of $16.40/month under the LNG export-Adjusted prices. For FPL/Gulf customers, a $4.39 increase is projected under the Reference scenario, which rises to a $15.56 increase under the LNG export-Adjusted scenario.

Figure 26 - LNG Export Residential Monthly Bill Impact - FPL/Gulf

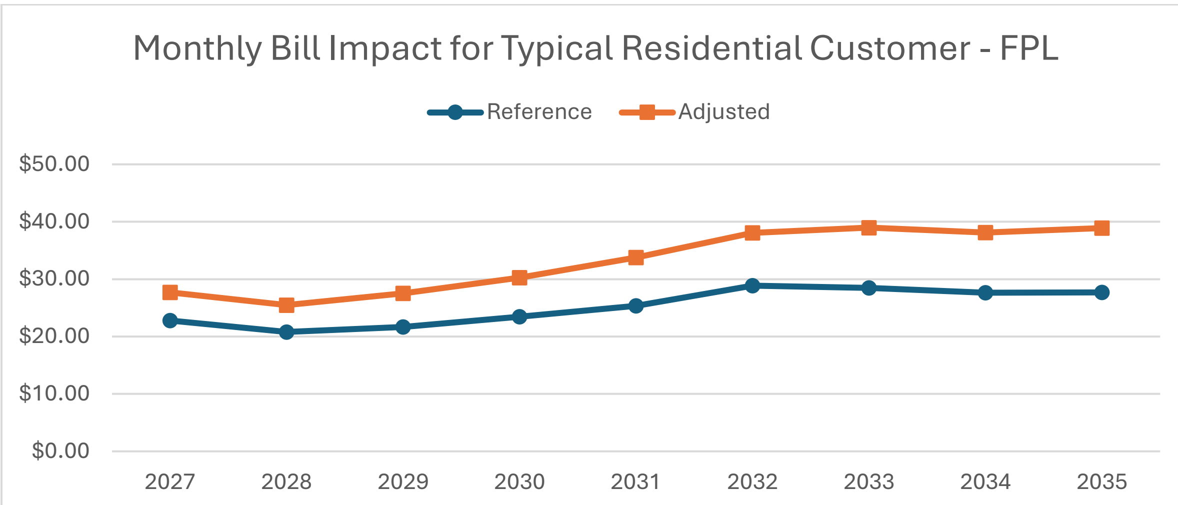


Figure 27 - LNG Export Residential Monthly Bill Impact - Duke

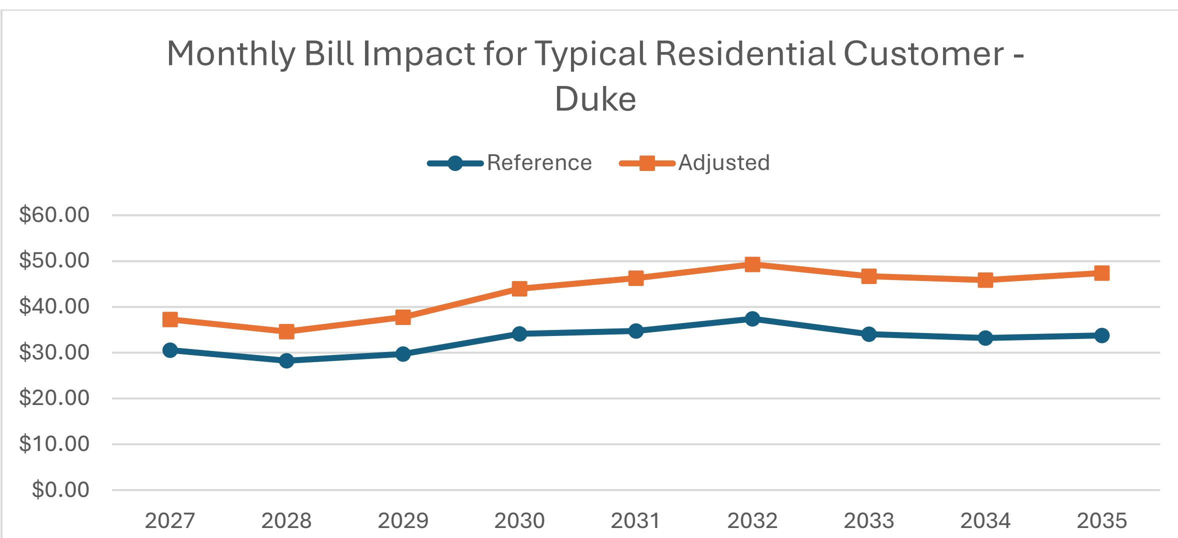
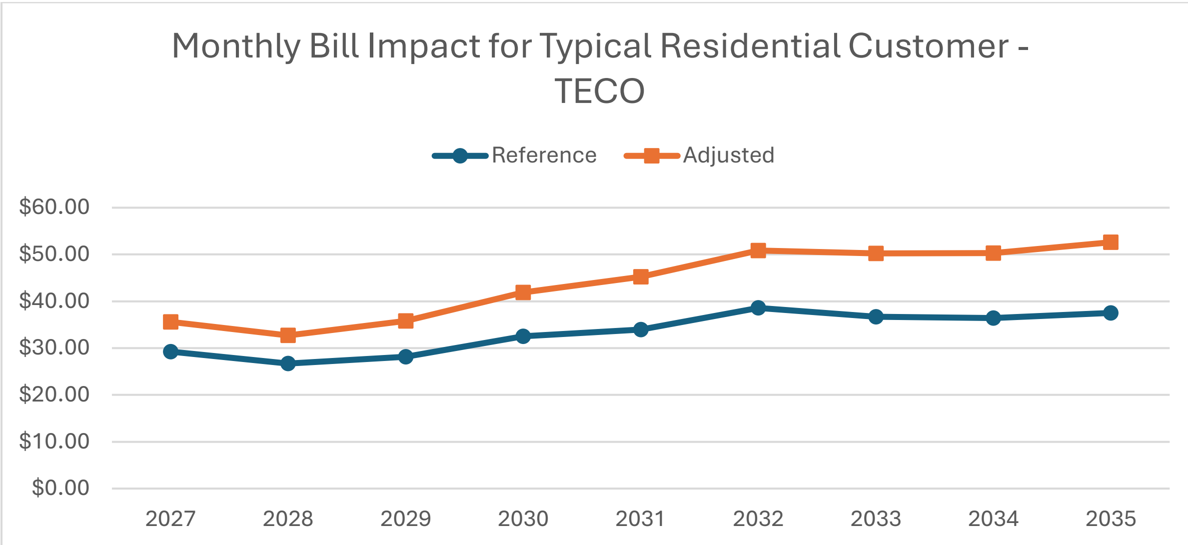


Figure 28 - LNG Export Residential Monthly Bill Impact - TECO



For all IOUs combined, the cumulative impact over the next decade of LNG export growth is expected to result in additional natural gas costs to Florida electricity consumers of between $18.48 billion and $22.32 billion compared to the EIA's Reference and Low Supply scenarios, respectively.

Conclusions

Increases in LNG exports from the U.S. are likely to amplify the existing natural gas-related price risks faced by Florida's electric consumers. Florida's electricity consumers already shoulder the burden of natural gas-related risks due to the state's high reliance on imported natural gas for electricity generation, the limited availability of substitute sources of electricity generation, and the geographic concentration of the state's natural gas supply.

As LNG export increases shift the fundamental dynamics of U.S. natural gas markets, Florida consumers will likely face higher electricity prices resulting from higher natural gas prices driven by LNG export demand, greater electricity price volatility as increased natural gas price volatility attributable to growth in LNG export volumes is passed to consumers in the form of unexpected increases in fuel costs, and higher risks associated with the availability of natural gas fuel during extreme weather events.

The Florida electric IOUs' most recent Ten-Year Site Plans from 2026 indicate declines in reliance on natural gas for electricity generation over the next decade, but those declines are far more moderate than projections in the 2025 Plans. Changes in policy, markets, and technology could drive further change in IOU Plans in ways that would further exacerbate natural gas-related risks to Florida electricity consumers. Recent developments such as policy changes that reduce incentives for non-fossil fuel electricity generation and that repeal and reverse existing pollution controls, as well as market developments such as rapid growth of new domestic natural gas demand to support electricity generation for data centers and other large loads, especially in the south/southeast region of the country, all have potential to magnify the price and reliability risks that Florida electricity consumers already face due to a high degree of reliance on natural gas.