Release date: Fall 2025

2026 GULF COAST ENERGY OUTLOOK

Gregory B. Upton, Jr. | David E. Dismukes | D. Andrew Owens
Chris McLindon | Tyler Gray | Garret Graves

LSU | Center for Energy Studies
LSU | Energy Institute

2026 Gulf Coast Energy Outlook

Gregory B. Upton, Jr.
David E. Dismukes
D. Andrew Owens
Chris McLindon
Tyler Gray
Garret Graves

Release Date: Fall 2025

Acknowledgments

The 2026 *Gulf Coast Energy Outlook* (*GCEO*) would not be possible without the help of many who contributed both time and financial resources. First, the input from dozens of industrial, governmental, civic, and trade organizations that requested having the last year's GCEO presented to their organizations is much appreciated. The feedback that was provided during these conferences and individual meetings continues to be instrumental in preparing the current report. While "crunching the numbers" is an important aspect of any forecasting process, the input provided by stakeholders who have an "on-the-ground" view of what is occurring in real time is equally valuable.

Special thanks are owed to Stephen Radcliffe (E. J. Ourso College of Business) for his media, editorial, and production expertise. Derek Berning, Nikkolas Monceaux, Sid Narra, and Ashma Pandey contributed to data collection and analysis included in this report.

Last, but certainly not least, a special appreciation is extended to Center for Energy Studies Sustaining Members.

- Platinum: **Air Products, Baton Rouge Clean Air Coalition, Entergy, ExxonMobil, LCA, Oxy, Shell,** and **Shintech**
- Gold: **Chevron, ConocoPhillips, Enverus, Jones Walker,** and **Phillips 66**
- Silver: **Cheniere, Cleco, Drax, Greater Baton Rouge Economic Partnership,** and **Placid**
- Bronze: **American Electric Power / Southwestern Electric Power Company (AEP/SWEPCO); Harris Deville & Associates; Kean Miller; Koch Companies Public Sector, LLC; LLOG; Louisiana Department of Conservation and Energy; Louisiana Oil and Gas Association (LOGA); The TJC Group;** and **Van Ness Feldman, LLP**
- Contributor: **EisnerAmper, Hood Baumann & Associates, Louisiana Economic Development, Regions,** and **Steelhead**

Table of Contents

List of Figures

List of Tables

1. Introduction

The annual Gulf Coast Energy Outlook (GCEO) is designed to provide stakeholders with an overview of current trends and expectations for the region's energy industry. The GCEO is a work product of Louisiana State University's Center for Energy Studies (CES). All CES research is supported by the Center's state appropriation, underscoring Louisiana's commitment to independent, data-driven energy analysis. CES is also grateful for its sustaining members, whose support helps make possible the dissemination of timely information and analysis on issues critical to the Gulf Coast economy, environment, and citizenry. Unless otherwise stated, the "Gulf Coast" region refers to Texas, Louisiana, Mississippi, and Alabama. In some instances, DOE reporting conventions require data at the PADD 3 level, which also includes Arkansas and New Mexico. Employment forecasts primarily focus on Louisiana and Texas. The forecast horizon generally extends through 2028 (approximately three years).

The sections below outline the key uncertainties and baseline assumptions framing this year's GCEO.

1.1 Policy Uncertainty

Perhaps the largest item of discussion with stakeholders this year has come around policy uncertainty. These discussions have centered around both state and federal policies. Novel to this year's GCEO, a section has been added specifically to address state and federal policies. This introductory section highlights some of the most notable changes as well as how GCEO incorporates such changes into the outlook.

The return of the Trump administration in January 2025 brought changes in federal energy policy with implications for Gulf Coast energy markets. The administration lifted the LNG export permit pause and extended LNG export terms through 2050. Since then, final investment decisions (FIDs) have been reached on several LNG projects, including the state's largest private foreign direct investment from Woodside's Louisiana LNG. Permitting timelines for oil and gas projects were also shortened under new "Emergency Permitting Procedures," while offshore wind leasing was paused and some existing leases are under review.

In addition, the administration implemented a 90-day pause on disbursements under the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA). While certain tax credits were later clarified as unaffected, the pause created a period of uncertainty for some projects. The One Big Beautiful Bill Act (OBBBA) subsequently restructured many IRA incentives. Section 45Q carbon capture credits remain in place, but "clean" electricity credits now face accelerated phaseouts, while incentives for nuclear, geothermal, hydropower, and storage remain intact. EV purchase tax credits were eliminated, and the methane emissions fee was repealed.

While many have expressed optimism about the Trump administration's pivot from an energy policy aimed at emissions reductions (under the Biden administration) to an energy policy aimed at energy production, many have also expressed concerns that energy policy has become increasingly political, with meaningful policy swings from administration to administration causing uncertainty. For example, while the Trump administration has prioritized LNG exports and offshore oil and gas production via executive actions, the administration has simultaneously prematurely ended tax credits for wind and solar and removed all areas of the OCS for offshore wind leasing. Offshore energy (both oil & gas and wind) and natural gas liquefaction are all examples of large capital-intensive projects that take years to complete. Thus, consistent energy policy across administrations is an important consideration for long-term project planning.

> **This year's GCEO assumes that the current federal framework continues through the forecast horizon (about three years). But we note that federal policy changes across administrations, and the resulting uncertainty this creates, has the ability to negatively impact energy investments.**

1.2 International Trade and Tariffs

Related to federal policies, international trade continues to create uncertainty for the Gulf Coast, which has become the nation's hub for exporting hydrocarbons and energy-intensive products. A consistent theme of prior year GCEOs is that the Gulf Coast region of the U.S. is a net exporter, with these exports driven by energy and petrochemical products. As also highlighted in prior year GCEOs, international trade frictions are a significant risk for the Gulf Coast energy sector.

The Trump administration's tariff program applies a baseline 10 percent tariff on all imports, with higher rates on certain products from key trading partners. Energy-specific provisions include tariffs on Canadian resources and restrictions on sourcing from "Foreign Entities of Concern" (FEOCs), particularly China and Russia.

At the same time, new specific trade agreements have expanded potential export opportunities. For example, the U.S.–EU Framework Agreement commits the EU to procure up to $750 billion in U.S. energy through 2028, though some question whether such ambitious targets are achievable given infrastructure and market constraints. Some have pointed to this trade agreement as aiding in the Gulf Coast's expanding LNG export capacity.

Tariffs have the ability to impact energy investments through two channels. First, companies looking to sell products overseas might see reciprocal tariffs, which can make it more difficult to find an international buyer for products. Second, capital projects require the purchase of machinery and equipment from all of the world to complete. Several project developers have cited specific cost increases due to tariffs. Thus, while some in the oil and gas industry were pleased with some of the policy changes in the prior section, tariffs were not generally viewed as favorable to investment.

> **This year's GCEO assumes that current tariff policies remain in place. Trade policies introduce uncertainty for Gulf Coast manufacturers through two channels: (1) making it more difficult to find international buyers for products due to potential for reciprocal tariffs and (2) higher input costs, especially for capital projects.**

1.3 Economic Outlook

Readers might recall that three years ago, many national forecasters were anticipating a recession beginning in 2023; however, a recession in the U.S. did not yet occur. As highlighted, GCEO believed that these concerns were driven largely by the fact that inflation was outpacing wage growth at the time. Earlier this year, concerns of a recession appeared again, and the stock market dipped significantly in February and April of 2025, spurred by trade uncertainties. The U.S. Bureau of Economic

Analysis estimates negative seasonally adjusted GDP growth in Q1 of 2025. But in Q2 seasonally adjusted GDP growth is estimated to be positive, and cumulatively, current estimates suggest GDP growth in the first half of 2025.

All-in-all, since the pandemic-induced recession in the first quarter of 2020, the U.S. economy has continued to expand. At the time of this writing, employment is above pre-pandemic peaks, unemployment remains below 4.5 percent, and wage growth is now outpacing inflation. Inflationary pressures have subsided; the Federal Reserve has stopped increasing interest rates and is expected to reduce interest rates in the coming months. It should be noted that GDP growth for the U.S. was negative in the first quarter of 2025 (concurrent with tariff announcements and a drop in the stock market), but was positive again in the second quarter.

Internationally, economic growth has also persisted, with the U.S., China, and India all continuing to experience real GDP growth per the most recent data available at time of writing[1] and organizations such as the IMF, OECD and World Bank are all forecasting global GDP growth in the coming few years, with this growth again driven by the growing developing world. A recurring theme of the GCEO, we continue to see announcements for export-oriented projects, as economic opportunities for the U.S. energy sector continue to be driven by international demand.

> **This year's GCEO modeling assumes that the U.S. will continue to experience economic growth and demand for energy globally will continue to rise. GCEO, much like years past, anticipates that long-run energy demand growth will lead to increased U.S. energy exports, especially to the growing developing world. In the event an economic slowdown does occur, this would make forecasts generally less optimistic.**

1.4 Electricity Demand Growth: From Projection to Reality

For nearly two decades, U.S. energy use in total BTUs has been relatively flat, with efficiency gains offsetting economic and population growth. Past GCEOs noted scenarios where electricity's share of energy could increase through adoption of EVs, heat pumps, and larger-scale data centers. Over the past two years, those scenarios have moved from projection to reality.

U.S. electricity consumption grew 2% in 2024 and is projected to continue rising at a similar pace. Growth is concentrated in the commercial (notably data centers have gained significant attention recently) and industrial sectors, alongside moderate contributions from growing EV adoption and residential electrification. Importantly, while total BTU consumption remains flat, electricity accounts for a larger share of that total, driving new power generation and infrastructure investment.

Three potential drivers for electricity demand growth were identified in last year's GCEO—electric vehicles, heat pumps, and data centers. Of the three, data centers are now front and center of discussions of near-term electricity demand growth, with IEA estimating U.S. demand projections for 2026 approximately 100 TWh higher than previous estimates.[2]

In Table 1 below, we present simple "what-if" calculations to give perspective on how three frequently discussed developments—EVs, heat pumps, and data centers—could affect both electricity demand and total U.S. energy use (quads). We emphasize that these are not forecasts or policy scenarios,

[1] Notably, the 27 countries within the European Union (in sum) and Japan, along with the other largest global economies, have experienced relatively flat real GDP over the past decade.
[2] International Energy Agency. Electricity 2025. Analysis and Forecast to 2027. Report downloaded 10/23/2025. Page 36.

but stylized calculations meant to illustrate scale. They assume each change occurs immediately and universally—conditions that are not realistic, but nonetheless informative for understanding energy-system dynamics.

First, if all light- and medium-duty vehicles on the road in the U.S. were instantly replaced with EVs, total energy consumption would fall by about 12.6 percent, even after accounting for line losses. This reduction reflects differences in conversion efficiency: utility-scale power generation is more efficient at turning fuels into useful energy than internal combustion engines (ICEs). Thus, although electricity demand rises, the overall system requires less total energy to move the same number of vehicles the same distance.

Second, we apply the same logic to residential and commercial heating. If all heating were immediately electrified via heat pumps, electricity consumption would rise by roughly 11.6 percent, but total energy use would fall by around 4 percent. Because heat pumps move heat rather than generate it, they can deliver the same level of service with much less energy input. In both the EV and heat pump cases, the implication is similar: total energy declines even as electricity's share of the energy mix increases.

Finally, we summarize publicly discussed estimates of potential energy growth from data centers, which have been the subject of heightened attention. We compile results from five recent reports, selecting the more aggressive growth case when multiple values are provided. In contrast to the electrification cases above, these calculations show increases in both electricity demand and total energy use, because we do not assume any offsets or efficiency gains from AI adoption elsewhere in the economy; and unlike EVs and heat pumps, new AI and hyperscale data centers are not replacing an existing technology like an internal-combustion engine or furnace that uses fossil fuel. Estimates from EPRI, IEA, and Goldman Sachs suggest data centers could contribute less than 1 percent of U.S. total energy and increase electricity consumption by 5–7 percent, while McKinsey and Boston Consulting Group offer more aggressive assumptions.

Taken together, the table illustrates that electrification of vehicles and heating tends to reduce total energy use while increasing electricity's share, whereas data centers tend to increase both electricity use and total energy. These exercises provide useful scale benchmarks as stakeholders evaluate evolving U.S. demand for energy.

Table 1: Theoretical potential impact on electricity and energy usage

Technology	*% Δ Electricity (TWh)*	*% Δ Energy (quads)*
Electric Vehicles	25.8%	-12.6%
Heat Pumps	11.6%	-4.0%
Data Centers		
EPRI - Higher Growth	5.6%	0.8%
IEA - Base Case	5.9%	0.9%
Goldman Sachs	6.8%	1.0%
McKinsey - Medium Scenario	10.4%	1.5%
Boston Consulting Group - High Case	17.7%	2.6%

Note: These are meant to be illustrative only, not a projection of future changes. Electric Vehicles and Heat Pumps consider full adoption for light duty vehicles and residences. Data Centers use 2024-2030 buildout estimations from multiple sources.

Sources: EV scenario uses data from EIA, DoT, and DoE. Heat pump scenario uses data from NREL's ResStock policy simulations. Data center scenarios use data from McKinsey (Oct 2023), EPRI (May 2024), Boston Consulting Group (Jun 2024), IEA (Apr 2025), and Goldman Sachs (Aug 2025).

GCEO continues to assume that U.S. total BTU consumption will remain flat, but electricity's share will increase. Availability of affordable electricity is increasingly cited as a reason for project location choice, even for investments outside the energy and petrochemical sectors.

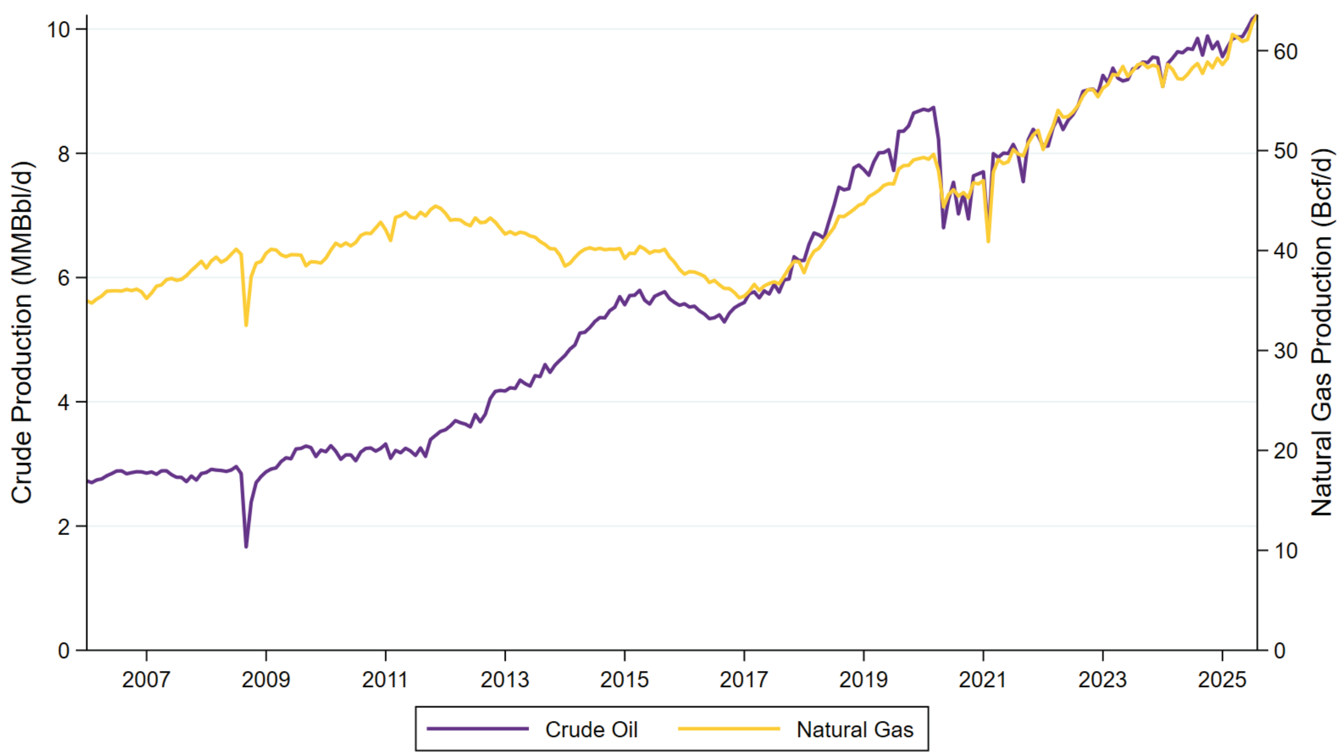
2. Crude Oil and Natural Gas Production and Prices

2.1 Crude Oil and Natural Gas Production

U.S. oil production continues to reach record levels, achieving an all-time high of 13.8 MMbbl/d in August 2025. Natural gas production has similarly established new records, currently running at a historical high of approximately 132 billion cubic feet per day (Bcf/d).

Gulf Coast oil and gas production trends are shown in Figure 1. The region has continued to demonstrate robust production growth over nearly two decades, with crude oil production reaching 10.2 MMbbl/d and natural gas production at 63.6 Bcf/d as of August 2025. Crude oil production has shown consistent growth throughout this period, rising from under 3 MMbbl/d in the mid-2000s to current record levels. Natural gas production has also increased substantially, with particularly significant growth since 2017, experiencing some temporary decline during 2020 before resuming its upward trajectory to current levels.

Figure 1: Gulf Coast crude oil and natural gas production



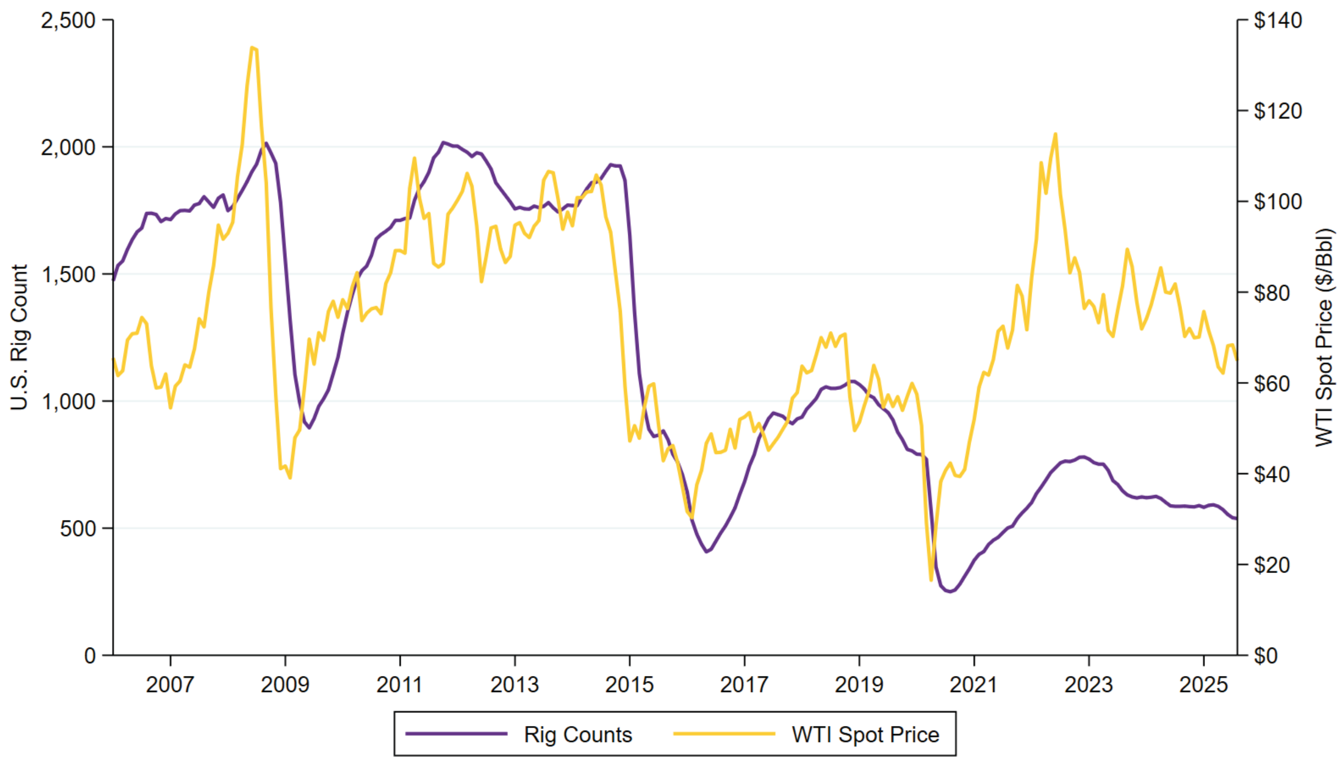
Source: U.S. Energy Information Administration. Petroleum & Other Liquids. Crude Oil Production. Natural Gas Gross Withdrawals.

Figure 2 highlights the relationship between U.S. rig counts and oil prices over the data period from 2006 to 2025. The data shows significant variation in drilling activity, with rig counts reaching a historical peak of over 2,000 in 2011 during the height of the unconventional oil boom. Following the

2014-2016 oil price downturn, when prices fell below $30 per barrel, rig counts declined substantially before recovering in subsequent years. More recently, rig counts peaked at 780 in December 2022 and have since gradually declined to 542 active rigs as of September 2025.

This decline has mirrored the drop in oil prices with typical industry lags. As discussed in Section 2.3, the GCEO anticipates that oil and gas production will continue to increase despite fewer active rigs, reflecting continued efficiency improvements in drilling and completion technologies. This has been a consistent theme of GCEOs in past years: production growth is driven by increased efficiencies, not necessarily increased active rigs and workers. Although not shown in the figure, Gulf Coast rig counts move in tandem with U.S. rig counts and exhibit a similar pattern relative to oil price movements.

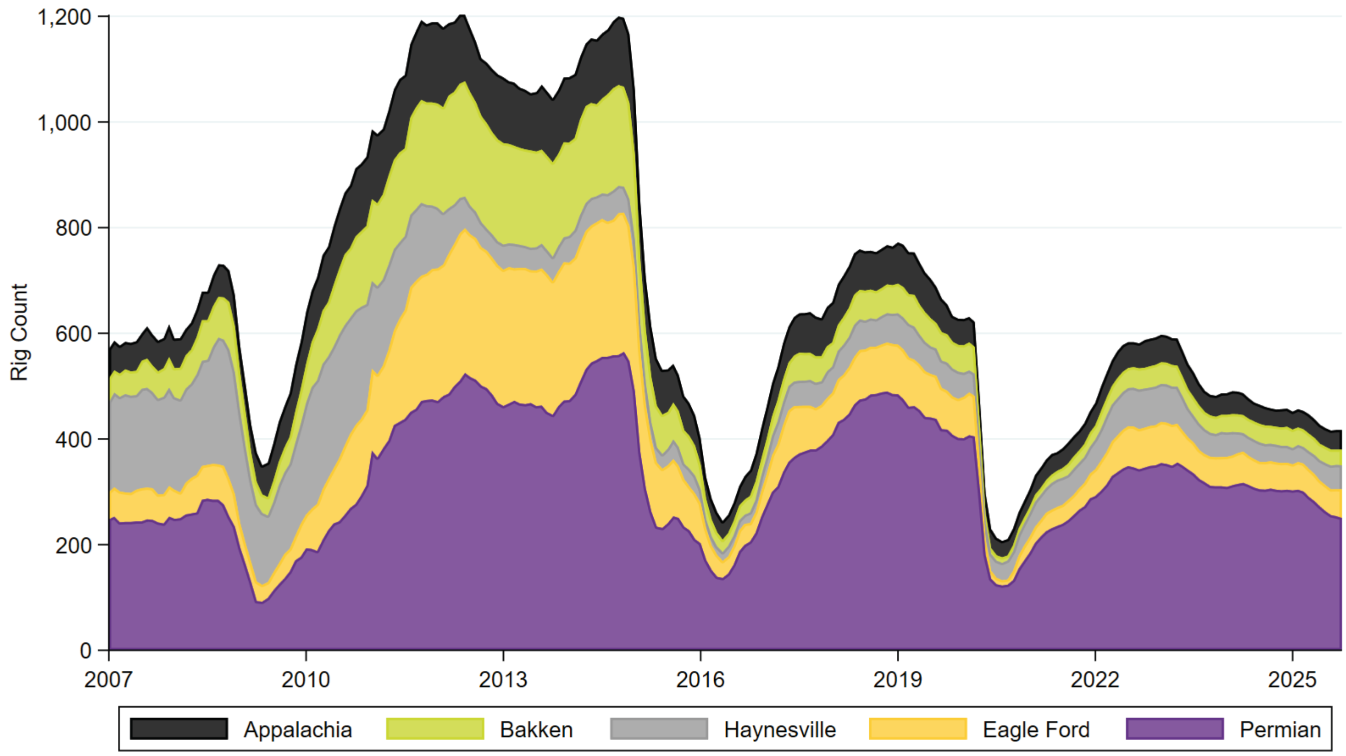
Figure 2: U.S. crude oil prices and rig count



Source: U.S. Energy Information Administration. West Texas Intermediate Spot Price. Baker Hughes Rotary Rig Counts.

Figure 3 displays rig activity levels in five U.S. production regions, as defined by EIA's *Short-Term Energy Outlook*. For the past several years, GCEO has noted that the Permian Basin had been the predominant U.S. shale play, and this continues to dominate, accounting for more than half of all active rigs in major shale plays. All five basins shown in Figure 3 have experienced reductions in rig counts since the beginning of 2023, with drilling activity declining approximately 9 percent year-over-year across major shale formations. More focus on Gulf Coast oil and gas production specifically will be provided in Section 2.3 below.

Figure 3: Rig counts in U.S. production regions



Source: U.S. Energy Information Administration. Short-Term Energy Outlook.

2.2 Commodity Pricing

Figure 4 shows recent trends in both crude oil and natural gas commodity pricing. The top panel shows historic trends, and pricing "epochs," whereas the bottom panel presents historic trends for natural gas pricing.

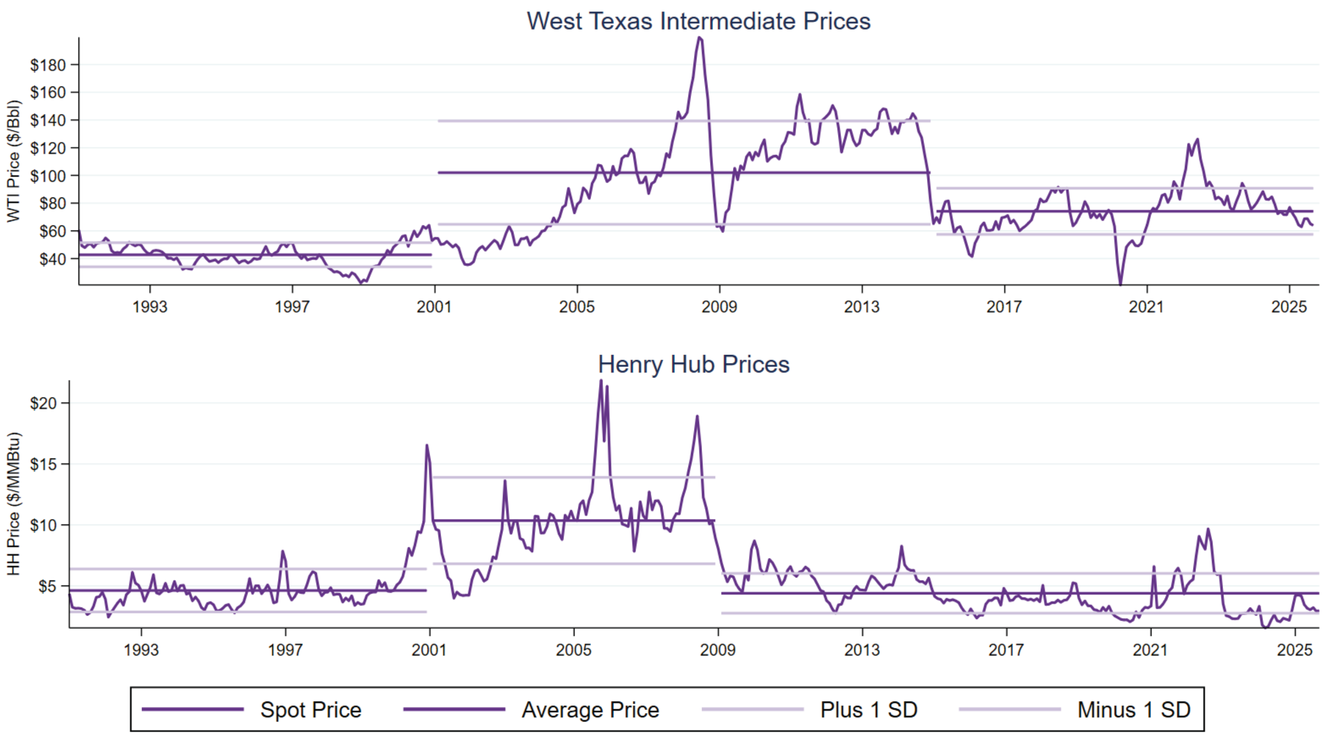
Historic natural gas pricing shows three separate epochs: (1) the period spanning the 1990s; (2) the period starting with the natural gas supply/pricing crisis of the 2000s; and (3) the post-recession period to current. These epochs differ in both their levels and variability.[3] The relevant question that was posed in GCEO over the past two years was whether natural gas prices had entered a new epoch that reflects a greater integration of U.S. natural gas markets to global markets. Prior to the advent of LNG exports, U.S. markets faced limited pricing exposure to changes in global markets.

The 2024 GCEO commented that the Russo-Ukrainian war and resulting sanctions on Russian natural gas, alongside the U.S. becoming the world's largest producer and exporter of natural gas, would likely result in substantially more, but still not total, integration. Through 2025, we have not observed a departure from this third "epoch" of natural gas prices, with current natural gas prices remaining relatively low. At this time, natural gas prices are still within the third epoch as described above. Some in industry have noted that if natural gas prices increase significantly due to U.S. prices converging

[3]Variability is shown as the standard deviation in the change in average monthly prices.

with global prices, this could (1) reduce the likelihood of LNG investments due to the fundamentals of price arbitrage, but (2) change the political willingness to sell a valuable commodity onto a global market while locally consumers pay higher prices. This will continue to be something GCEO watches in coming years.

Figure 4: Historical inflation-adjusted oil and natural gas price

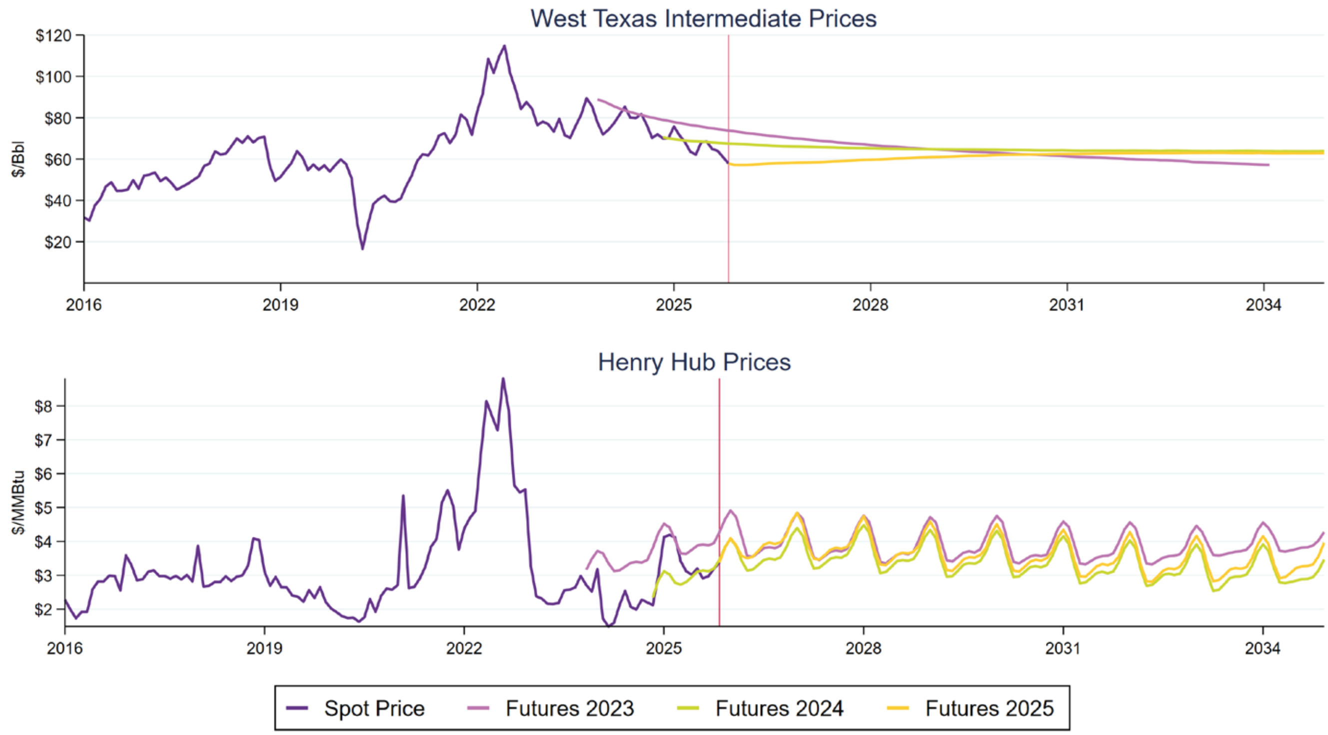


Source: U.S. Energy Information Administration. West Texas Intermediate Spot Price (top) and Henry Hub Natural Gas Spot Price (bottom). Inflation adjustment based on U.S. Consumer Price Index sources from the Bureau of Labor Statistics.

The trends in inflation-adjusted crude oil pricing continue to underscore how the unconventional revolution has led to dramatically reduced volatility relative to past pricing epochs. Pre-pandemic crude oil prices are shown in the middle range of the third epoch. The pandemic crashed crude oil prices, which bottomed out at a monthly average of less than $17 per barrel in April 2020 before quickly rebounding. But the global economic recovery alongside the war in Ukraine put significant upward pressure on oil prices in 2022. Since then, inflation-adjusted oil prices have steadily declined and now fall within the lower range of the third epoch.

Figure 5 compares historical prices and futures for both the West Texas Intermediate (WTI) crude oil price (top panel) and Henry Hub natural gas price (bottom panel). Unlike Figure 4, both energy commodity prices are shown in nominal dollars (i.e., no inflation adjustment). Also, futures prices are shown for the most recent data available, alongside the futures prices listed in the two prior editions of the GCEO to illustrate how futures markets have evolved over the last several years.

Figure 5: Oil and natural gas price outlook



Source: New York Mercantile Exchange Henry Hub Futures Price. Sources from S&P Global Market Intelligence. Red vertical line represents November 2025. Most recent futures price as of October 2025.

There are several notable observations based on Figure 5. First, markets continue to anticipate that oil prices will converge in the long run to around $60 per barrel. When prices shift outside of this range due to a shock (e.g. pandemic, geopolitical tensions, etc.), markets continue to anticipate convergence to a similar long-run price. At the time of this writing, oil prices are in backwardation: the WTI spot price is $58 per barrel for November and the anticipated price by the end of 2025 is about $57 per barrel. Futures prices over 2025-2030 gradually rise, moving from $57 to $63 per barrel, indicating a moderate upward market expectation over the next few years.

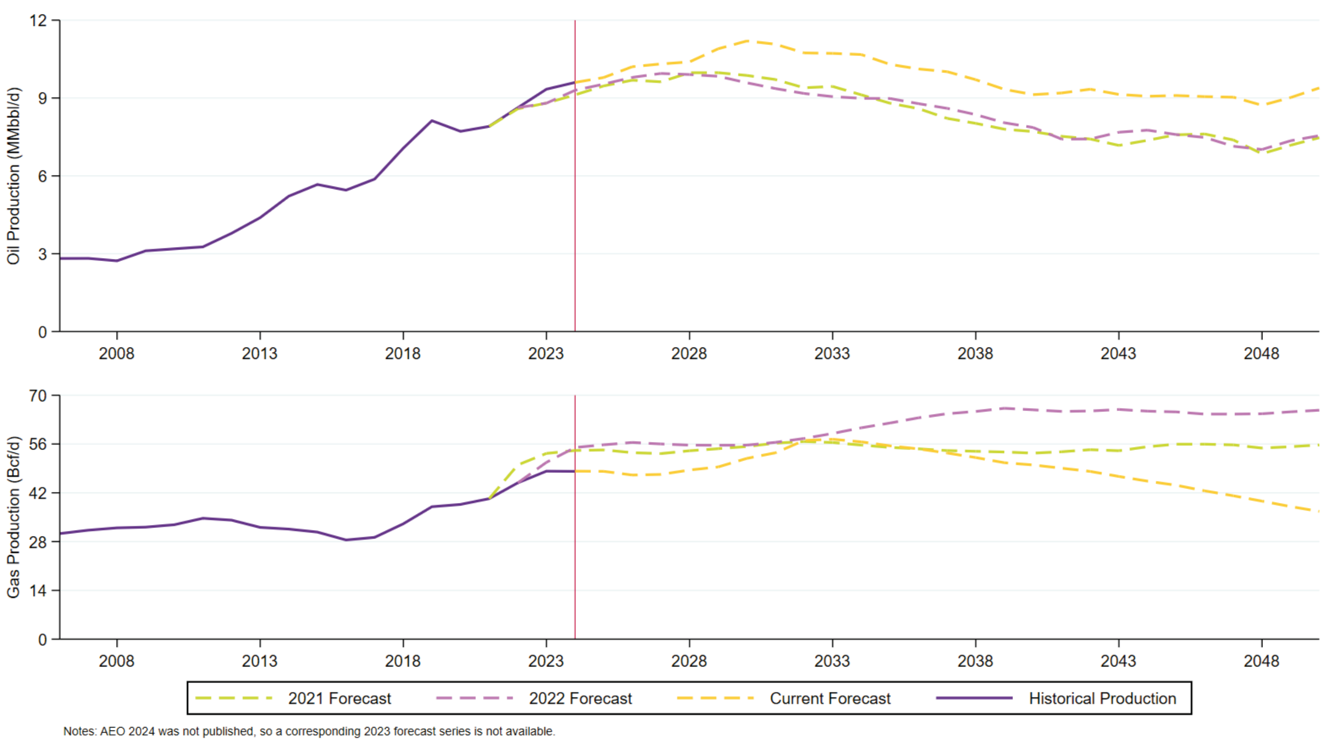
Natural gas prices are illustrated in the bottom panel of Figure 5. Natural gas prices are quite similar to what was anticipated last year at this time, and as shown in Figure 4 natural gas prices are at the low end of the prices experienced over the past decade. It is incredible to see how quickly U.S. natural gas prices have converged back to long-term norms in the wake of the global supply disruption that came from the Russian invasion of Ukraine in early 2022 and resulting sanctions. In the long run, futures markets anticipate natural gas prices to oscillate between about $2.8 to $4.5 per MMBtu. As will be discussed later, European and Asian markets have not experienced the same rapid convergence to pre-Russian invasion of Ukraine norms, and this has continued to create a comparative advantage for the Gulf Coast in attracting capital for projects in the processing and exporting of hydrocarbon-based products from the Gulf Coast region. It is this comparative advantage on natural gas prices that continues to drive investment in LNG export and chemicals.

2.3 Outlook: Crude Oil and Natural Gas Production

Figure 6 shows crude oil and natural gas production forecasts for the Gulf Coast based on the AEO (Energy Information Administration, Annual Energy Outlook) forecast model. In prior years, GCEO has utilized the *Enverus Prodcast* Model for production forecasts. We utilize AEO for two reasons; first AEO did a significant update to its forecasts now allowing for more granular geographic breakdowns, and second the *Enverus Prodcas*t Model has been significantly updated, thus apples-to-apples comparisons from prior year model runs are no longer straightforward to produce. Following tradition, both figures show the current forecast as well as those in the past two years' AEOs, as EIA did not publish the AEO in 2024.

Gulf Coast crude oil production is anticipated to increase over the forecast horizon.[4] For perspective, in 2023 regional crude oil production averaged 9.3 MMbbl/d. In calendar year 2025, which at the time of this writing is partially completed, AEO estimates Gulf Coast oil production to average 9.8 MMbbl/d, or an increase of approximately 5 percent. By 2032, Gulf Coast oil production is forecasted to reach 10.7 MMbbl/d. This oil production forecast remains essentially unchanged from the previous AEO. As with prior years, there is plenty of oil in the ground to sustain a decade of production growth. Although not shown here, AEO also estimates U.S. oil production to decrease 1.2 percent by 2032.

Figure 6: Gulf Coast oil and natural gas production forecast



Source: U.S. Energy Information Administration, Annual Energy Outlook, Author's Calculations

[4]Note that the definition of the Gulf Coast region in the AEO model differs slightly from political boundaries, due to the inherently geological nature of the model.

Figure 6 shows that Gulf Coast natural gas production is also anticipated to continue to grow over the next decade.[5] In 2023, Gulf Coast natural gas production was about 48.5 Bcf/d, with AEO projecting the same estimates for 2024. By 2032, AEO estimates Gulf Coast natural gas production to reach around 58 Bcf/d, followed by a gradual decline through 2050. Similarly, Gulf Coast oil production is forecasted to peak around 2030 before gradually declining through the forecast horizon. Thus, both oil and natural gas production in the region are anticipated to experience a decade of growth even though oil and natural gas prices have been remarkably flat on an inflation adjusted basis, with this price trend expected to continue based on futures markets. Although not shown graphically, both U.S. oil and natural gas production are also anticipated to grow over the coming decade.

2.4 Drilling & Completion Technologies

As noted in Section 2.1, the GCEO anticipates that oil and gas production will continue to increase despite fewer active rigs, reflecting continued efficiency improvements in drilling and completion technologies. Two specific examples in 2025 include a record-breaking well drilled in the Haynesville Formation with a total measured depth of 32,001 feet and a lateral length of 20,034 feet.[6] The well is currently producing 80 MMcf/d, which is also a record for the shale play.[7] The second example is from the deepwater Wilcox trend in the Gulf of Mexico. A floating production facility reached its target production rate of 100,000 bopd producing from reservoir depths of approximately 30,000 feet and utilizing industry-leading high pressure 20,000 psi production equipment.[8] These technological advancements underscore the recent trends of increasing rates of production and decreasing rig counts.

2.5 OCS Federal Lease Sale

2025 will also see the first federal lease sale in the Gulf OCS since 2023. The Bureau of Ocean Energy Management (BOEM) published the Final Notice of Sale in the Federal Register on November 10, 2025 announcing that on December 10, 2025, they will open and publicly announce bids received for blocks offered in the Gulf of America (GOA) Outer Continental Shelf (OCS) Oil and Gas One Big Beautiful Bill Act Lease Sale 1 (Lease Sale BBG1). BOEM is holding this sale pursuant to the One Big Beautiful Bill Act (OBBBA) and in accordance with the Outer Continental Shelf Lands Act (OCSLA). The last federal lease sale in the Gulf OCS, Lease Sale 261, was held on December 20, 2023. A total of 352 bids from 26 companies were submitted on 311 tracts totaling 1,728,343 acres. The total of high bids for Sale 261 was over $382 million.

[5] Note that AEO was not released in 2024.

[6] Deep Well Services

[7] RBN Energy, LLC

[8] Beacon Offshore Energy, LLC

3. Midstream Constraints and Pipeline Activity

Geographic differences in crude oil and natural gas prices often drive pipeline development. If prices at “Point A” are higher than “Point B” at a given time, firms have the incentive to develop transportation resources to capture this price differential (or “basis”).

As in prior year GCEOs, Figure 7 compares differences in prices of West Texas Intermediate (WTI) and Louisiana Light Sweet (LLS). Three vertical lines are drawn. The first vertical line marks pricing levels as of January 2007, the date at which the EIA began tracking crude oil and natural gas unconventional production in its *Drilling Productivity Report*. The second line marks pricing levels as of May 2012, when the Seaway pipeline was reversed. Seaway initially moved crude from Freeport, Texas, on the Gulf Coast, to Cushing, Oklahoma, where WTI is priced. After Seaway was reversed, the pipeline carried crude produced in the Mid-Continent to Gulf Coast refineries. This line divides a regime of increasing internal shipping constraints from a regime where those constraints were relieved. The third line marks pricing levels as of December 2015, when the U.S. government lifted the crude oil export ban.

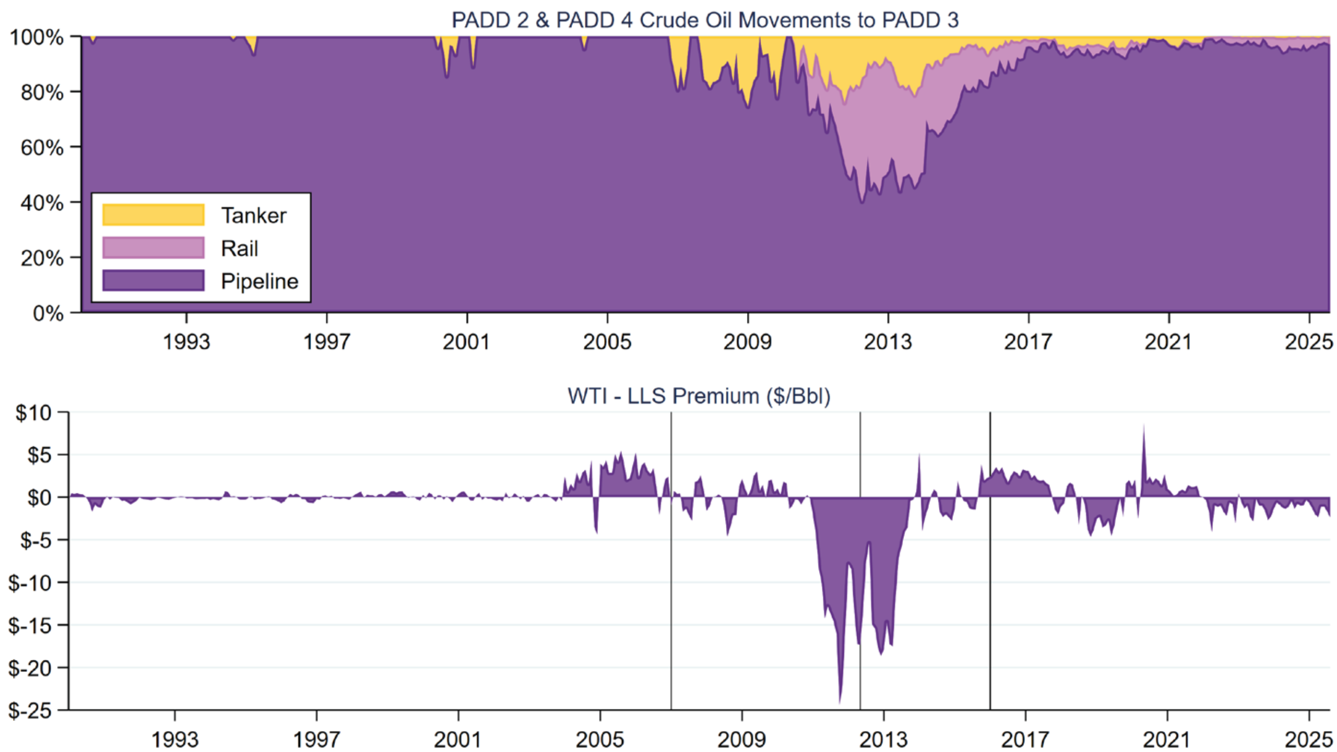
The top panel of Figure 7 shows the share of crude oil transported from PADD 2 and PADD 4 in the Mid-Continent (states in the Rocky Mountain and Midwestern regions) to PADD 3 on the Gulf Coast. From 1990 to 2007, almost all crude was transported from the mid-continent to the Gulf Coast via pipeline. Shippers used pipelines because rail and tankers were more expensive on the margin. During this time WTI and LLS moved in lockstep. In fact, by April 2012, more than half of the crude shipped from the mid-continent to the Gulf Coast went via high-cost barge and rail, as pipelines were at full capacity. Almost immediately after the reversal of the Seaway pipeline, this trend stopped, and the share of crude shipped via pipeline began to recover.

The LLS-WTI premium closely mirrors changes in the mode of transport over the 2007-to-2015 time period. This close correlation between shipping and prices can explain between one-half to three-quarters of relative price movements. Prior empirical research has investigated the degree to which refinery composition, captured by API crude oil gravity, can explain these differentials.[9] Evidence of shipping constraints, but not refining constraints, is observed.

For the past five years or so, crude markets have remained relatively balanced, with a small premium to LLS in the more recent years. The GCEO anticipates this small premium to persist over the forecast horizon and that more than 95 percent of crude shipped from the Mid-Continent to the Gulf Coast will continue to come from pipelines. Although oil production is anticipated to increase, due to the investment in pipeline infrastructure over the past decade, the need for increased barge and rail shipments is unlikely at this time. Last year’s GCEO questioned whether pipeline additions could become necessary once U.S. oil production reached pre-pandemic levels. Now that production has marginally surpassed those levels and reached historical highs, time will tell whether pipeline constraints will become prevalent in the future. Currently, markets appear to be in balance, with a small share of oil shipped via tanker and rail and price differences being minimal across space. If oil production continues to grow, GCEO will keep watch on whether price differentials emerge sending the price signal for additional pipeline capacity.

[9] Agerton and Upton, 2019. Decomposing Crude Price Differentials: Domestic Shipping Constraints or the Crude Oil Export Ban? *The Energy Journal*, Vol. 40, No. 3.

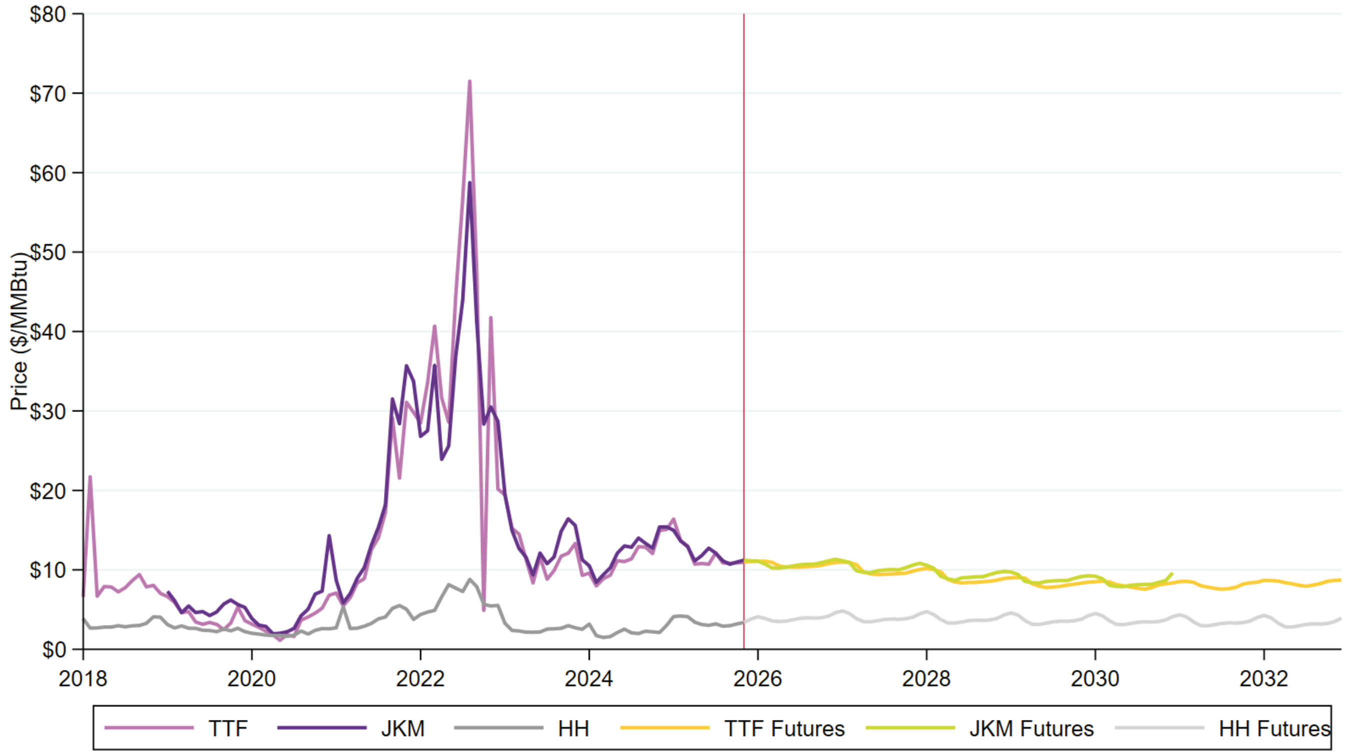
Figure 7: PADD 3 crude oil movements by transportation type



Source: U.S. Energy Information Administration, West Texas Intermediate Spot Price and Light Louisiana Sweet First Purchase Price. Movements between PADD Districts, by pipeline, tanker and barge, and rail.

The more notable spatial price differences instigating mid-stream investment are natural gas prices internationally. Figure 8 shows historical series for Henry Hub (Gulf Coast of U.S.), Title Transfer Facilty (TTF—European benchmark), and the Japan Korean Marker (JKM—Asian benchmark). As recently as 2020, natural gas was trading at a similar price (within ~$0.50 per MMBtu) in the U.S., Europe, and Asia. But this has changed dramatically over just a few years. In the most recent full month of data available, October of 2025, natural gas prices in Asia (represented by JKM) and Europe (represented by TTF) were approximately 240 percent more expensive than the Gulf Coast. Thus, the mid-stream constraints for natural gas are between *international* locations; not as much within the U.S. While not shown here, international oil prices do not vary nearly as much as natural gas, with Brent (in Europe) trading at $4 per barrel more than West Texas Intermediate (in the U.S.) at the time of this report. As mentioned previously, the price discount between Gulf Coast natural gas prices compared to Asia and Europe is perhaps the most important factor in both the continued investment in LNG export as well as the competitiveness of the petrochemical sector.

Figure 8: Henry Hub (HH), Japan Korean Marker (JKM) and Title Transfer Facility (TTF) natural gas prices



Source: Bloomberg Terminal, U.S. Energy Information Administration, S&P Global Market Intelligence.

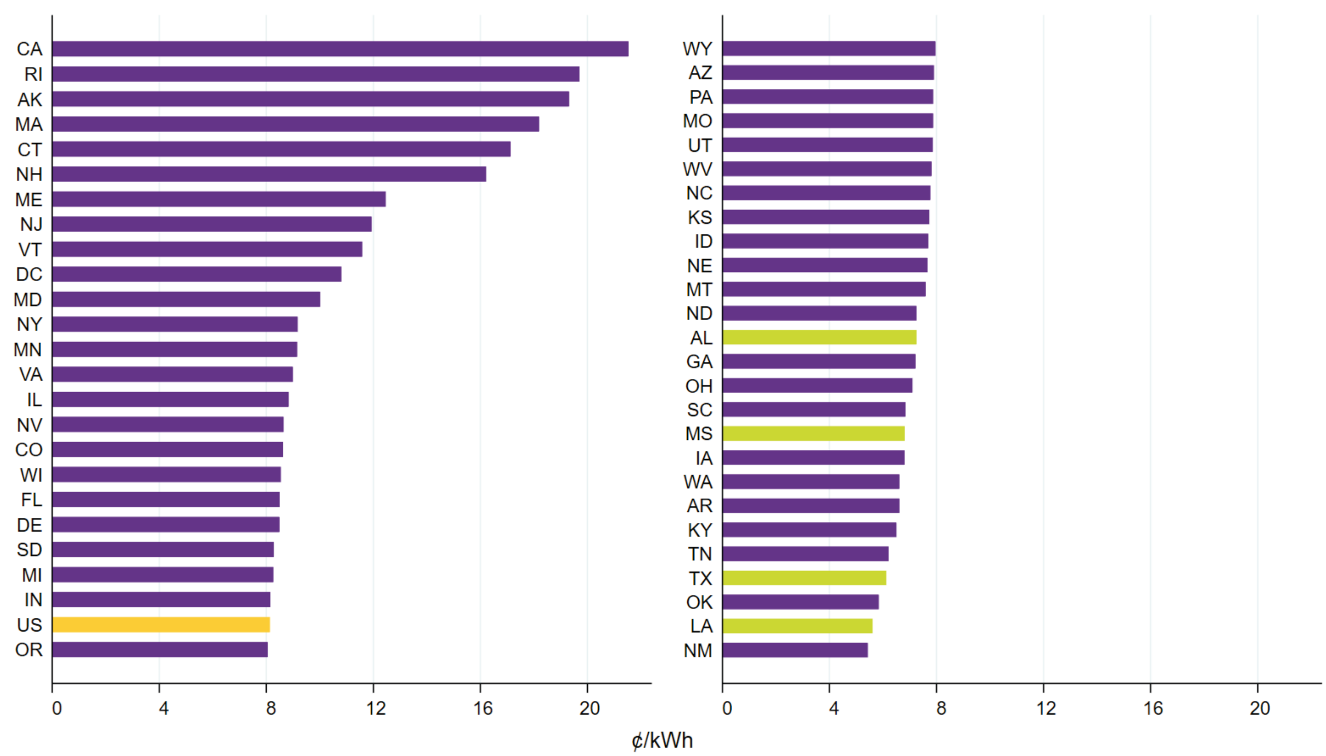
4. Power Sector

4.1 Average Retail Prices

Electricity is a key input for manufacturing, and for certain energy-intensive operations, power can comprise as much as 75 percent of total variable operating costs. As such, electricity price competitiveness relative to other states is important in regional economic development. The Gulf Coast continues to have competitive industrial retail electricity rates, particularly the State of Louisiana. Figure 9 shows recent (2024) average industrial retail electricity prices for the U.S. and each state.

The U.S. average industrial electricity rate in 2024 was 8.1¢ per kilowatt-hour (kWh), which is considerably higher than the Gulf Coast weighted regional average of 6.2 ¢/kWh, giving the region a 20+ percent cost advantage. All Gulf Coast states are below the national average industrial retail price, with Louisiana having the lowest regional retail electricity industrial price at 5.6¢/kWh, the second lowest in the U.S. The average industrial retail rate in Texas in 2024 was 6.1¢/kWh, about 8.5 percent higher than Louisiana.

Figure 9: Average retail industrial electricity prices



Source: U.S. Energy Information Administration (EIA) 861 annual data.
Retail sales of electricity to ultimate consumers. Hawaii (34.1 ¢/kWh) is excluded from the figure.

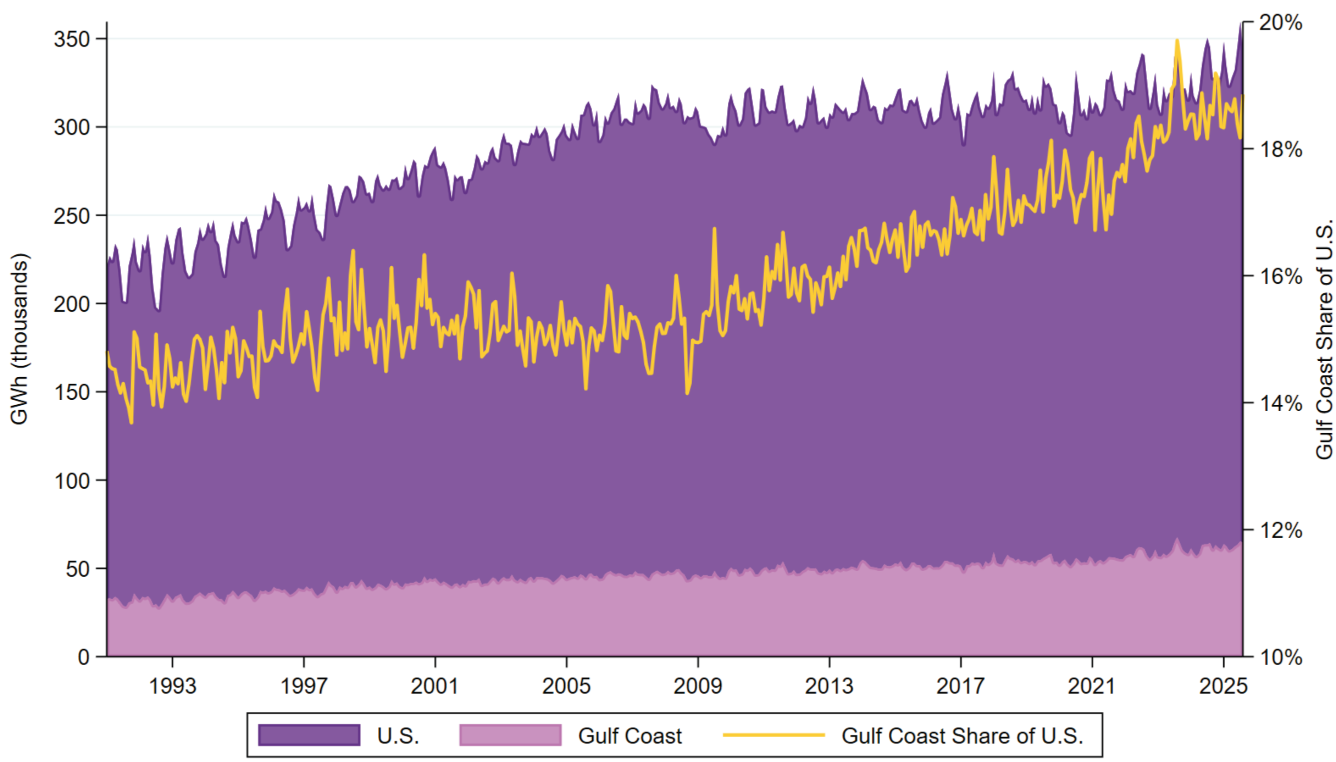
The Gulf Coast has been competitively priced relative to the national average for the last decade. Average industrial prices also decreased in the Gulf Coast region in 2024 relative to 2023 and 2022 levels due to lower natural gas and wholesale power market prices. During the 10-year period from

2015 to 2024, the Gulf Coast average industrial electricity price increased 8.9 percent versus the U.S. average industrial electricity price increase of 17.6 percent.[10] Additionally, the Gulf Coast saw significant growth in industrial electricity sales during the past 10 years at 36.0 percent versus U.S. average growth of only 4.9 percent. From 2015 to 2024, industrial electricity sales growth varied across Gulf Coast states: Alabama declined 5.2 percent, Mississippi increased marginally by 1.1 percent, Louisiana grew 15.9 percent, and Texas led with nearly 60 percent growth.

4.2 Sales Growth

Figure 10 shows trends in both U.S. and regional electricity sales. First, total U.S. electricity sales growth has been relatively flat over the last 10 years, increasing by only 5.8 percent over a decade; a growth rate of less than one percent per year. In fact, U.S. industrial electricity sales have yet to reach their late 1990s peak, whereas the Gulf Coast region has seen growth, increasing by 36.0 percent relative to 1990 levels led by Louisiana and Texas. Note this is a growth rate of approximately 1 percent per year. Although not reflected in the chart, the Gulf Coast's growing share of U.S. overall electricity sales is driven largely by growth in industrial sales. The Gulf Coast region accounted for 20 percent of U.S. industrial sales in 2015 and, at time of writing, accounts for almost 26 percent of nationwide industrial sales. This growth in industrial sales has been largely spurred by energy manufacturing activity in Louisiana and Texas, which will be discussed further in Section 5.

Figure 10: U.S. and Gulf Coast total electricity sales



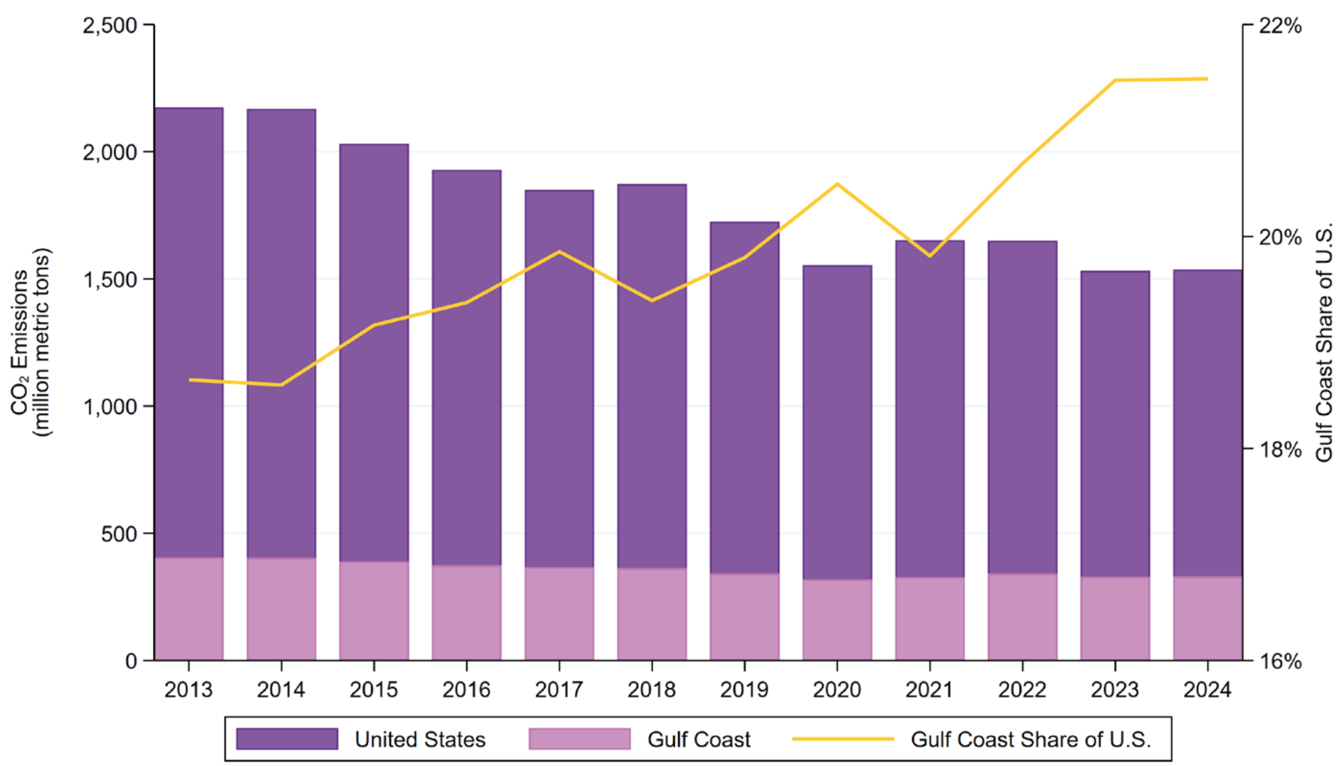
Source: U.S. Energy Information Administration 861 monthly data.
Retail sales of electricity to ultimate consumers.

[10] Note that both the Gulf Coast and U.S. average industrial price changes are below the change in the Producer Price Index during the same 10-year period.

4.3 Carbon Dioxide Emissions

Carbon dioxide (CO_2) emissions associated with power generation are provided in Figure 11. Note that this data is available with a lag and thus is only available until the calendar year 2024. Between 2013 and 2024, U.S. and Gulf Coast power-generation-related GHG emissions decreased by 29 percent and 19 percent, respectively. These decreases are attributable to retirement of coal and less efficient gas-fired steam generation, growth of utility-scale renewable energy (mainly wind and solar PV), and thermal efficiency gains by the region's utilities, mainly through investment in combined cycle gas turbine (CCGT) generation. While CO_2 emissions increased temporarily both nationwide and in the Gulf Coast between 2020 and 2022 due to higher natural gas prices that led to greater utilization of coal-fired power plants, the trend reversed in 2023, with total U.S. emissions reaching their lowest point. Preliminary 2024 data from the EIA indicates that total U.S. energy-related CO_2 emissions declined by less than 1 percent, or 23 million metric tons, and emissions from electricity generation remained relatively flat. Given pending retirements of certain coal units and growth of renewable energy in the region, particularly large-scale solar PV projects and hybrid projects that incorporate energy storage, GCEO anticipates a continued trend of reduced power sector CO_2 emissions.

Figure 11: U.S. and Gulf Coast CO_2 emissions from electricity generation



Source: U.S. Energy Information Administration. Electricity. Emissions by plant and by region.

4.4 Generation Capacity Investment

Figure 12 shows historic and projected power generation capacity by fuel source for the Gulf Coast region. According to projections developed by S&P Global Market Intelligence, approximately 91,000

MW of solar PV generating capacity is currently in the planning phase or under construction in the Gulf Coast region. In the Midwest Independent System Operator, Inc. (MISO) wholesale market alone, Louisiana currently has approximately 15,600 MW of solar PV, wind, energy storage, or hybrid renewable plus energy storage capacity in the interconnection queue being studied with an additional approximately 7,300 MW of renewable resources having completed the interconnection process with some of those projects under construction. The amount of solar PV capacity in the MISO queue in Louisiana is significantly less than the approximately 30,000 MW of solar PV capacity reported in last year's GCEO, a decrease largely attributable to recent reforms designed to address queue management. To reduce the pervasive withdrawals and speculative projects that were crowding the queue, MISO—in coordination with FERC—has increased milestone payments, introduced automatic withdrawal payments, and capped the volume of new queue entries. In addition to these queue management reforms solar tax credits were sunset early as part of the One Big Beautiful Bill Act which also likely influenced projects decisions to leave the queue.

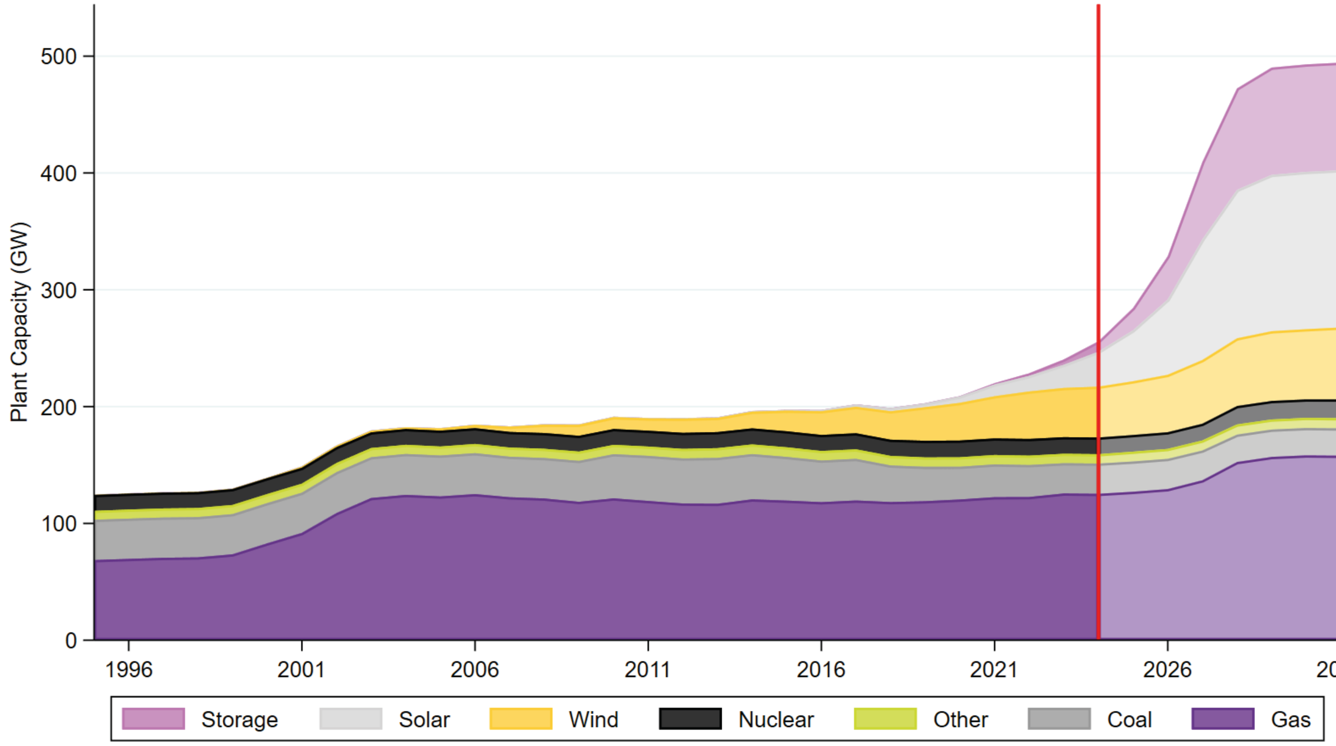
As a result, project volume has dropped sharply since last year's GCEO, but industry partners comment that remaining proposals are more viable and are likelier to be constructed and successfully interconnect to the transmission grid. Thus, the total effect of the policy changes on utility scale solar PV that ends up getting actually built is likely smaller than the reduction in projects in the queue.

Thus, although the growth rate for solar PV is likely lower than was anticipated in last year's GCEO, significant utility scale solar buildout is likely in the coming years. For perspective, solar PV capacity was less than 400 MW in the four-state Gulf Coast region as recently as 2011. Figure 12 also shows over 15,000 MW of wind capacity in the planning phase, much of that within the Texas ERCOT wholesale market although there are several wind projects being studied in Louisiana representing total capacity of 1,159 MW. Additionally, approximately 31,000 MW of natural gas capacity is currently being planned in the region.

Note that Figure 12 shows installed capacity, not share of electricity generated. For perspective, in 2024, natural gas accounted for 43 percent of utility-scale electricity generated nationwide, nuclear for 18 percent, coal for 15 percent, wind for 10 percent, and solar for 5 percent.[11] Total carbon-free generation in the U.S. accounted for approximately 39 percent of total utility-scale electricity used in 2024. Given the pace of new construction and planned unit retirements, renewable energy's share of electricity generation is likely to increase, but natural gas will continue to be the largest fuel source for electricity generation for the foreseeable future.

[11] U.S. Energy Information Administration. Electricity Data Browser, 1.1 Net generation by energy source: total – all sectors and 1.1.a Net generation by renewable sources: total – all sectors for 2024.

Figure 12: Gulf Coast power generation capacity and outlook



Source: S&P Global Market Intelligence, Historical and Future Power Plant Capacity.

4.5 Future Electricity Growth and Resource Adequacy

From 2000 to 2020, U.S. electricity sales (MWh) growth slowed from about 2 percent annually in prior years to about 0.5 percent annually as U.S. manufacturing declined in many areas and investments in energy efficiency in homes and buildings reduced usage. While overall electricity sales have been flat in the U.S. over the last 20 years, there is significant variation between states. North Dakota leads the U.S. by far with a 183 percent increase in total electricity sales comparing 2024 to 2004; on the other end of the spectrum, Hawaii has seen electricity sales decline by 17 percent over the same timeframe. Louisiana has seen overall electricity sales grow 20 percent over the last 20 years, which is roughly twice the U.S. average.

But industry partners are now forecasting a break in this historical trend and significant ramp up in load. With respect to the region, Entergy Corporation is now forecasting that its five regulated utilities will see total electricity sales grow by 52 TWh annually in 2029 versus 2024 led by industrial MWh sales growing between 13 and 14 percent annually. Similarly, American Electric Power (AEP), which serves portions of Northwest Louisiana through its SWEPCO subsidiary and has other utility operations spanning from Texas to the Midwest, forecasts 28 GW of company-wide incremental load growth led by strong data center demand along with approximately $72 billion of capital investment planned for 2026 through 2030. Cleco Power has also touted electricity sales growth opportunities tied to Louisiana's pro-business climate as well as its electrification and decarbonization efforts in shareholder presentations.[12]

[12] Presentation made at EEI Financial Conference held November 9-11, 2025

The potential for rapidly accelerated electricity sales growth, coupled with recent and pending retirements of older fossil fuel generating plants in the Gulf Coast states and the U.S. more broadly, may present challenges to ensuring on-going resource adequacy (i.e., having sufficient generating capacity available to meet peak load plus a target reserve margin). In areas experiencing higher levels of growth, it is reasonable to expect that utilities and independent generators will respond with investments in new firm, dispatchable generating capacity as well as renewable resources. Hybrid projects that add energy storage to intermittent renewable resources like wind and solar PV also have the potential to grow in the future. However, certain areas of the U.S. are experiencing challenges with near-term resource adequacy with adverse impacts on wholesale markets and consumer prices. For example, the PJM regional transmission operator (RTO) oversees a wholesale market that encompasses all or parts of 14 states most of which are fully deregulated where consumers have choice of electricity supplier. In PJM's two most recent capacity auctions, prices have spiked by approximately 10x over 2023 levels contributing to rate increases ultimately being passed on to consumers. According to PJM's Independent Market Monitor (IMM), much of the recent increase in PJM's capacity price is being attributed to large new loads like data centers that have been connected to the transmission grid without a concurrent build-out of additional new supply.

Utility regulators and policymakers also play a role in maintaining resource adequacy. As noted in last year's GCEO, the Louisiana PSC adopted new rules in June 2024 requiring that utilities subject to the PSC's jurisdiction meet a minimum percentage of their MISO-assigned annual capacity obligation (MCO)[13] and also expanded its integrated resource planning (IRP) rules to apply to the state's electric cooperatives.[14] On October 1, 2025, the Louisiana PSC Staff issued a report summarizing the first annual resource adequacy filings made by utilities in May. Notably, of the 11 electric utilities that submitted a report, only three (3) utilities "fully met the current requirements of the MCO Order…", which were Cleco Power, LLC, Entergy Louisiana, LLC, and Concordia Electric Cooperative, Inc.[15] For the remaining electric utilities, the PSC Staff noted various deficiencies, which resulted in a utility falling below one or more pre-set percentage thresholds in a future MISO planning cycle. Another issue noted by PSC Staff is that several utilities partially rely on out-of-state resources, including those as far away as Michigan.

Each electric utility in Louisiana operates within either the MISO or Southwest Power Pool, Inc. (SPP) wholesale market both of which have undertaken various actions to address the backlog of projects in their respective interconnection queues as well as meet anticipated significant near-term load growth. For example, MISO recently implemented a new Expedited Resource Addition Study (ERAS) to accelerate the review of proposed generators. The ERAS process will consider a maximum of 68 projects before it is scheduled to sunset on August 31, 2027. To-date, a total of 47 projects representing approximately 26,500 MW have been submitted into ERAS. Louisiana is well represented with a 1,640 MW gas-fired project proposed by Entergy Louisiana, LLC,[16] among the first 10 projects that MISO is evaluating.

[13] Louisiana PSC Docket No. R-36263; In re: *Consideration of Whether the Commission Should Adopt Minimum Physical Capacity Threshold Requirements for Load Serving Entities*.

[14] Louisiana PSC Docket No. R-36262; In re: *Possible Modification of the Commission's Integrated Resource Planning Rules to Remove the Exemption for Electric Cooperatives*.

[15] Louisiana PSC Docket No. X-37566; In re: *Annual Resource Adequacy Demonstrations pursuant to General Order dated July 16, 2024 (R-36263; MCO Docket); Staff's Compliance Report* dated October 1, 2025.

[16] MISO New Center. *MISO announces first 10 ERAS project. Projects span MISO's full territory, supporting reliability and economic growth*. September 4, 2025.

5. Regional Energy Manufacturing Investment

5.1 Overview

GCEO energy manufacturing investment continues to expand. This economic run, fueled by low-cost and widely available natural gas supplies, has lasted close to 15 years and is still continuing. The nature of this investment, however, continues to change as firms leverage their expansive world-scale capacity base on a more qualitative basis, by doubling down on additional levels of investment designed to improve operating efficiencies, climate concerns, and new profit opportunities.

Over the past five years, the region has increasingly seen considerable incremental capital investments in such technologies as low-emissions/clean hydrogen and ammonia production, carbon capture and storage (CCS), biofuels, and other forms of "clean" energy infrastructure. Three years ago, the GCEO itself started to recognize and transform the way these investments were represented in ongoing outlooks, and that specialized emphasis continues in the 2026 GCEO.

Prior GCEOs have repeatedly noted how sensitive these transition investments are to ongoing public policy support at the state and federal level, particularly the tax incentives arising in the IRA of 2022. Public policy continues to influence these decarbonization investments and as will be discussed below, is leading to headwinds for many recently announced projects.

Lastly, data centers of all type, including large "hyperscale" facilities, are changing the energy landscape along the Gulf Coast. These data centers facilitate a variety of information technology functions that range from cloud-based computation and enterprise data storage to content delivery networks streaming. While these facilities are not "energy manufacturing" in a traditional sense, they are large energy users and are impacting Louisiana's energy economy. A new addition to this year's GCEO includes a survey of this energy intensive activity including the impacts of one additional large energy user that has been proposed, the Hyundai Steel mill in Donaldsonville.

5.2 Regional Trends

The 2026 GCEO shows that the Gulf Coast region has and continues to attract an outsized level of energy manufacturing investment relative to other regions in the U.S., particularly in the industrial Midwest. However, even here along the Gulf, projects are starting to exhibit longer development timelines driven by financing,[17] supply-chain,[18] trade, and policy uncertainty.[19] Importantly, while developers continue to have long run confidence about the region's fundamentals (deep-water ports, pipeline density, skilled labor, energy infrastructure variety and capacity, and proximity to feedstocks and export markets), these same developers are building in longer development timelines on prior-announced and newly announced projects.

The current investment portfolio is influenced by a variety of clouded and mixed macroeconomic signals that include easing but continued elevated interest rates, slower growth in key export markets, and tighter global engineering, procurement, and construction (EPC) support, and skilled labor

[17] United States Department of Energy (DOE). Fact Sheet: Temporary Pause on Pending Applications for Authorization to Export Liquefied Natural Gas to Non-FTA Countries. Washington, D.C., 2024.

[18] Reuters. Rising *U.S. labor costs threaten to derail new LNG projects*. New York, 24 June 2024.

[19] S&P Global Commodity Insights. U.S. Gulf leads global blue ammonia price falls in Jan amid project uncertainty. Houston, 18 February 2025.

availability. More importantly, recent project announcements have been influenced by a variety of public policy factors that include: (1) implementation details for clean-hydrogen tax credits (45V) and related domestic-content guidance;[20] (2) federal and state Class VI well-permitting for geologic CO_2 storage;[21] and (3) ongoing debates around transmission and pipeline siting and increasingly growing local opposition to CCS siting.[22] Collectively these factors can (a) lengthen front-end engineering and financing and/or (b) considerably delay project permitting and early development process. The net result are projects that have longer anticipated commercial operation dates (COD) and more risk.

Commercial structures are also evolving, influencing project announcements and development. Consider that LNG offtake agreements and clean ammonia contracts are increasingly including indexed pricing, destination/delivery flexibility, increased and diversified investor participation, and decarbonization attributes (requiring additional "transition" related investment dollars).

Meanwhile, petrochemical developers are focusing on a series of efficiency investments attempting to reduce debottlenecking, increase energy-efficiency, and address emissions-control issues that minimize costs and preserve global competitiveness under volatile margins. On balance, policy clarity would appear to be a more attractive and critical catalyst for FIDs rather than new, large, and yet uncertain financial incentives.

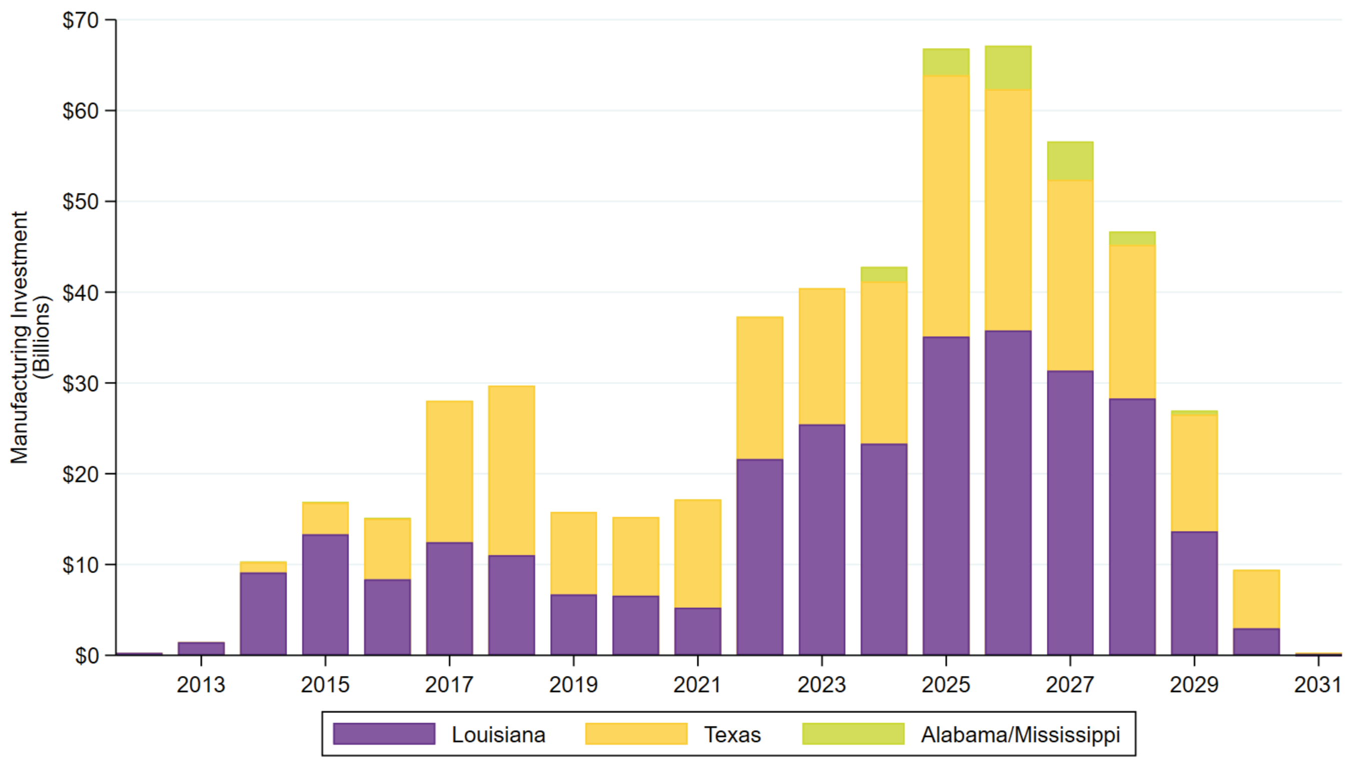
Since 2011, cumulative Gulf Coast energy-manufacturing investment has reached close to $337 billion, led by Louisiana (~$180 billion) and Texas (~$153 billion), as shown in Figure 13. Louisiana's investment trends follow recent LNG build-outs while Texas leads in diversified non-LNG chemical and refining capacity (see "Non-LNG" categories).

[20] Implementation details for clean-hydrogen tax credits (45V) and related domestic-content guidance U.S. Department of Treasury; Internal Revenue Service. "Credit for Production of Clean Hydrogen and Energy Credit." *Federal Register*, Washington D.C. January 10, 2025.

[21] Federal and state Class VI well-permitting for geologic CO_2 storage U.S. Environmental Protection Agency. "Class VI Wells Used for Geologic Sequestration of Carbon Dioxide." Washington, D.C., 2025

[22] Debates around transmission/pipeline siting and growing local opposition to CCS siting Congressional Research Service. Siting Challenges for Carbon Dioxide (CO_2) Pipelines. Washington, D.C., November 30, 2023.

Figure 13: Regional energy manufacturing investment

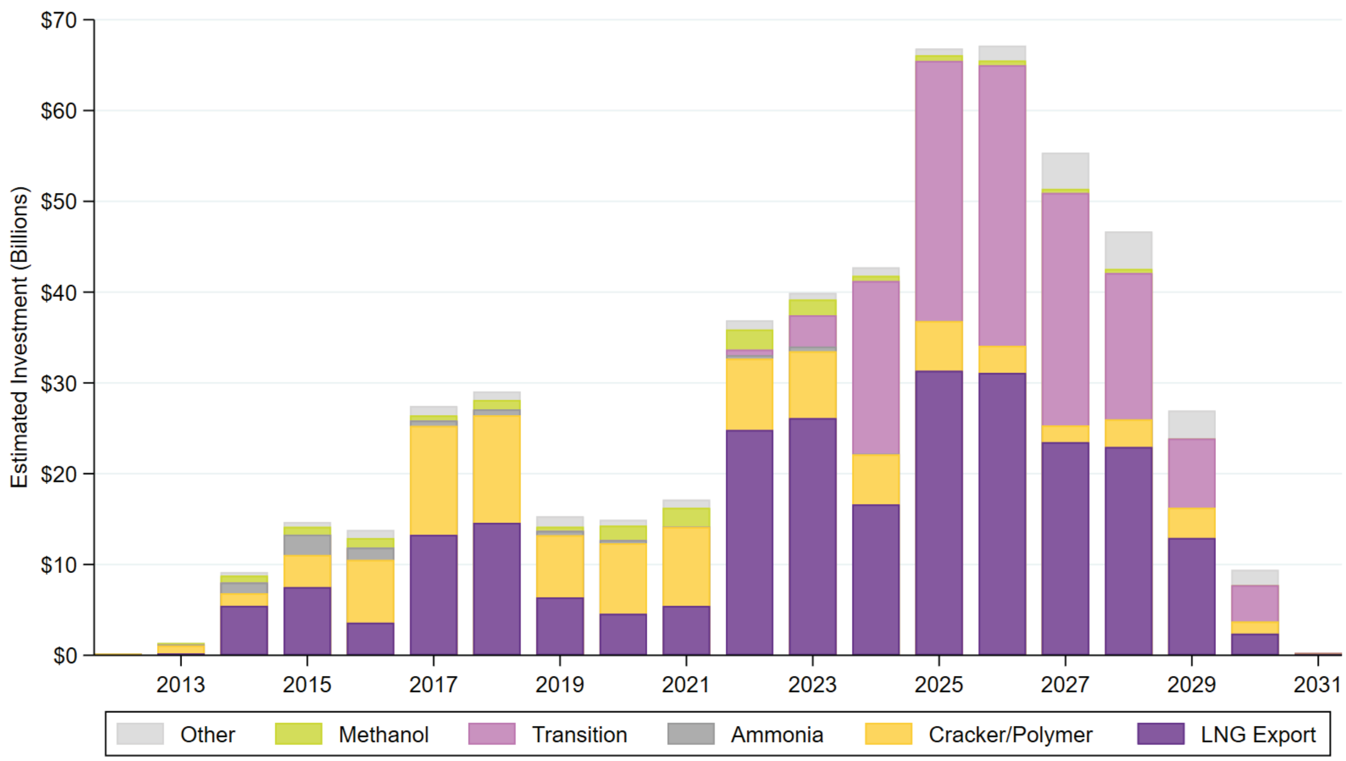


Source: Author's construct. Note: Hyundai Steel mill included.

As shown in Figure 14, annual capital formation has been cyclical, seeing an initial near-term peak around 2018, around the height of the shale-gas revolution, softening with 2018 trade frictions, Asian industrial deceleration, and ultimately, the global pandemic. A substantial regional recovery arose in 2022, setting a new investment high of around $37 billion with increases each and every year since that time.

Regional investment has primarily been focused heavily (in dollar terms) on LNG export facilities. However, over the last two years (2024-2025) transition investments across the Gulf Coast have surged and hold a dominating position in the overall regional total capital investment portfolio, especially in Louisiana where transition investments are starting to dominate LNG.

Figure 14: Regional energy manufacturing investment by sector (2012 to 2025)



Source: Author's construct from public press releases. Note: Other category includes residue catalyst production, air separation unit production, nitric acid production, solvent production, steel mills, rubber production, plastics production, sawmills, propane dehydrogenation.

5.3 Investment Outlook and Uncertainty

The 2026 GCEO has identified around $273 billion in total energy manufacturing investment announcements to 2031 (Table 2). Note that uncertainty and risk abound and thus this should not be interpreted as an estimate of the capital invested, but instead as the identification of announced projects. Key risks include financing costs, EPC inflation, supply-chain tightness, global economic performance and demand uncertainty, and evolving federal guidance on credit qualification for IRA tax incentives and financial support. The primary near-term challenge, however, is finding regulatory clarity. Absent that, developers will continue to sequence modules and delay FIDs while preserving options. At this point in time, it is likely that continued uncertainty will result in deferred projects.

Table 2: Gulf Coast projected energy manufacturing investments

Year	Texas LNG	Texas Non-LNG	Texas Transition	Texas Total	Louisiana LNG	Louisiana Non-LNG	Louisiana Transition	Louisiana Total
	(million $)							
2025	12,508	5,272	11,018	28,797	17,267	1,433	16,394	35,095
2026	12,160	3,264	11,149	26,573	15,955	1,308	18,520	35,782
2027	8,907	3,216	8,913	21,036	12,198	2,456	16,691	31,345
2028	3,717	4,502	8,717	16,936	18,450	2,437	7,392	28,279
2029	3,327	4,500	5,044	12,872	9,540	1,543	2,575	13,658
2030	1,332	1,573	3,535	6,440	1,050	1,450	468	2,968
2031	104	120	28	253	23	-	31	54
Total	**$ 42,054**	**$ 22,448**	**$ 48,404**	**$ 112,906**	**$ 74,483**	**$ 10,627**	**$ 62,071**	**$ 147,181**

Year	Other Gulf Coast LNG	Other Gulf Coast Non-LNG	Other Gulf Coast Transition	Other Gulf Coast Total	Total Gulf Coast LNG	Total Gulf Coast Non-LNG	Total Gulf Coast Transition	Total Gulf Coast Total
	(million $)							
2025	1,562	125	1,243	2,930	31,337	6,830	28,655	66,822
2026	2,984	568	1,243	4,795	31,098	5,140	30,912	67,150
2027	2,370	606	-	2,975	23,474	6,278	25,604	55,356
2028	773	686	-	1,459	22,939	7,626	16,110	46,674
2029	56	371	-	427	12,923	6,414	7,619	26,956
2030	-	6	-	6	2,382	3,030	4,003	9,415
2031	-	-	-	-	127	120	59	307
Total	**$ 7,744**	**$ 2,362**	**$ 2,486**	**$ 12,592**	**$ 124,281**	**$ 35,437**	**$ 112,961**	**$ 272,680**

On a sectoral basis, LNG continues to be one of the Gulf Coast's marquee investments (given the size of any individual project or project expansion), with Louisiana and Texas accounting for the vast majority of North American LNG capacity additions. The 2026 GCEO identifies as much as $124 billion in continued announced LNG facility investment.

Recently announced LNG projects are now focusing on multi-train expansions (e.g., Plaquemines, Cameron Phase II, Corpus Christi Stage III, Rio Grande LNG), sustained, at this point in time, by European and Asian demand for natural gas supply diversification (Europe) with most contract tenors extending into the 2040s. Project economics hinge on EPC cost discipline, gas-supply basis, and the carbon intensity of liquefaction, where efficiency upgrades and electrification are increasingly evaluated given market demand.[23,24]

[23] U.S. Department of Energy (DOE). 2024 LNG Export Study: Energy, Economic, and Environmental Assessment of U.S. LNG Exports. Washington, D.C., 2025.

[24] McKinsey & Company. Crunch Time in the North American LNG Industry: How to Meet Demand. Houston, TX, December 7, 2023.

Refining investment (see “Non-LNG” category) tilts toward reliability, energy efficiency, and fuels compliance rather than greenfield capacity. Petrochemicals benefit from advantaged ethane and proximity to export terminals; however, margin cyclicality and continued Asian economic doldrums temper outlooks. Developers are emphasizing phased debottlenecking and brownfield expansions with shorter paybacks given these risks. Most of these non-LNG related investments are anticipated to arise in Texas ($22 billion) as opposed to Louisiana ($11 billion).

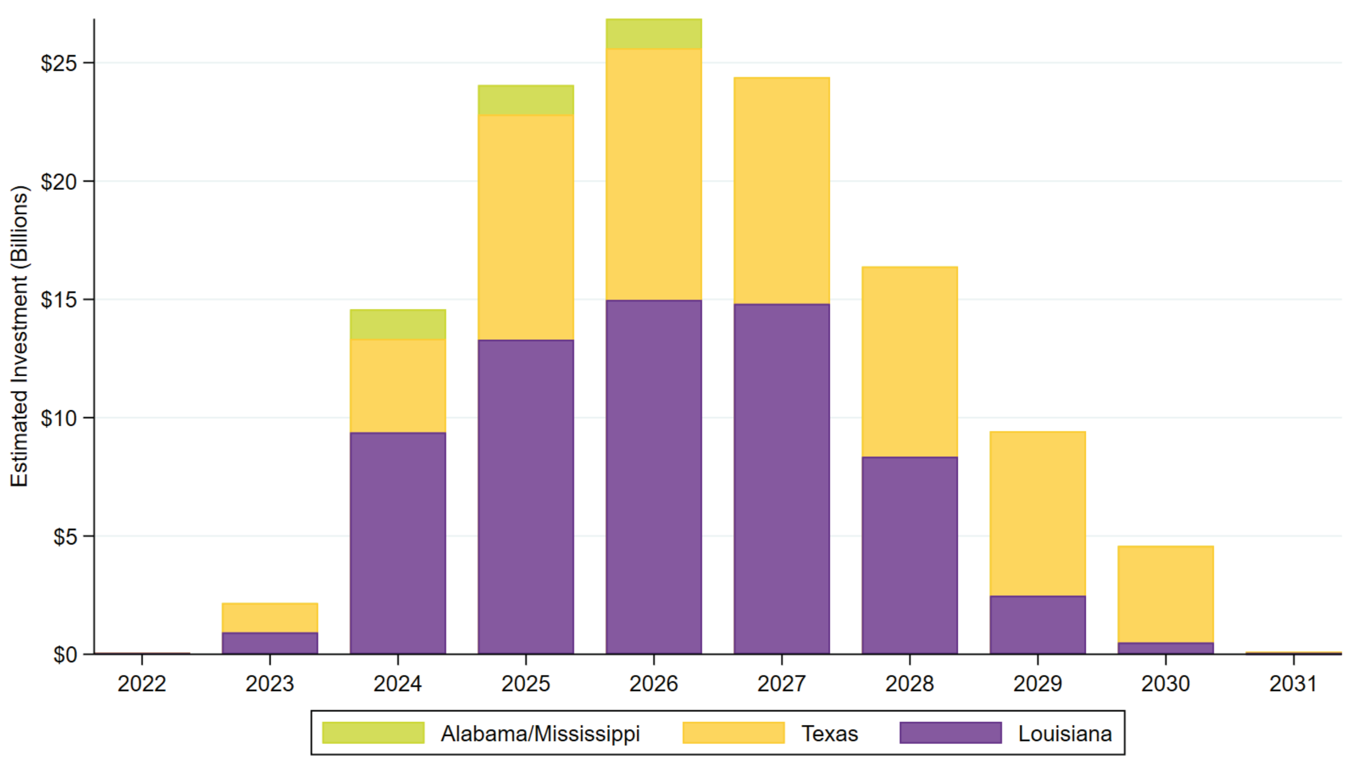
Transition investments continue to be strong but highly concentrated in Louisiana and exposed to the policy whims, and political outcomes in D.C. The 2026 GCEO anticipates as much as $113 billion in new Gulf Coast transition investments, most of which ($62 billion) are slated to be developed in Louisiana.

5.4 Regional Transition Investment Decomposition

Transition investments are now a central character in the Gulf Coast energy manufacturing development story, second only to LNG investment. These transition investments can be generally decomposed into those dedicated to CCS, clean hydrogen and ammonia, and “other categories” like biofuels and batteries.

The 2026 GCEO envisions around $62 billion of regional transition capex dedicated to clean hydrogen/ammonia (“green” and “blue”) with close to $40 billion in CCS projects which face considerable policy challenges and uncertainties; see Figure 15 for a decomposition of transition investments by state.

Figure 15: Regional transition investment decomposition



Source: Note: Author’s construct. Other includes biofuel, battery manufacturing, EV manufacturing, solar panel components.

5.4.1 Clean Hydrogen & Ammonia

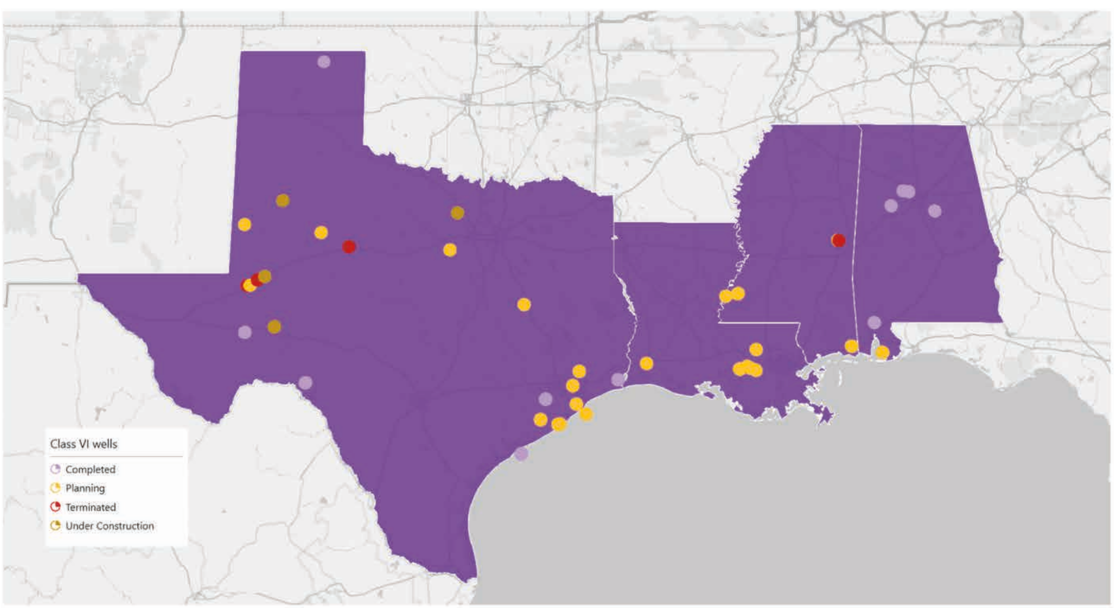
These regional investments reflect one of the purest and potentially profitable "pivot" for existing regional energy manufacturing particularly in the commodity chemical sector. Clean hydrogen and ammonia have the ability to leverage existing Gulf Coast chemical production capacity and bundle that capacity with new expansions designed to also leverage legacy pipeline corridors, an expansive natural gas value chain, affordable electricity, and deepwater transportation access. Over the past several years, the major factor holding such investments back has been the necessary financial "lagniappe" to push these projects over the economic hurdle, and, until recently, the IRA appeared to be the vehicle to get over the economic finish line.

However, increasingly, transition project developers are having to deal with the realities of questionable and uncertain 45V eligibility (electric-grid matching, additionality),[25] electrolyzer supply chains constraints,[26] and ammonia export logistics.[27] While many projects are still "on the books" some are reporting ambiguous CODs and outlooks. If current policy and economic trends continue, future GCEOs may have to critically assess and handicap certain project outlooks in this investment class.

5.4.2 CCS

The Gulf Coast's momentum clearly changed when Louisiana received Class VI primacy. Currently announced storage capacity totals are led by Texas (~121 Mtpa) with Louisiana following (~88 Mtpa), and Mississippi/Alabama contributing smaller volumes.[28] Gulf storage hubs (saline formations and depleted reservoirs) underpin decarbonization of ammonia, hydrogen, refining, and petrochemical facilities and may enable carbon-managed LNG.

Figure 16: Regional CCS wells (Class VI) by location and status



Source: National Energy Technology Laboratory Carbon Capture and Storage database and EPA Class VI well permits.

[25] International Renewable Energy Agency (IRENA) and World Trade Organization (WTO). Enabling Global Trade in Renewable Hydrogen and Derivative Commodities. Abu Dhabi and Geneva, 2024.

[26] International Energy Agency (IEA). Global Hydrogen Review 2024. Paris, 2024.

[27] Koerber, M. (2025). Clean Hydrogen Across the Atlantic? Policy Alignment and Transatlantic Cooperation in the Emerging Hydrogen Economy. American Council on Germany.

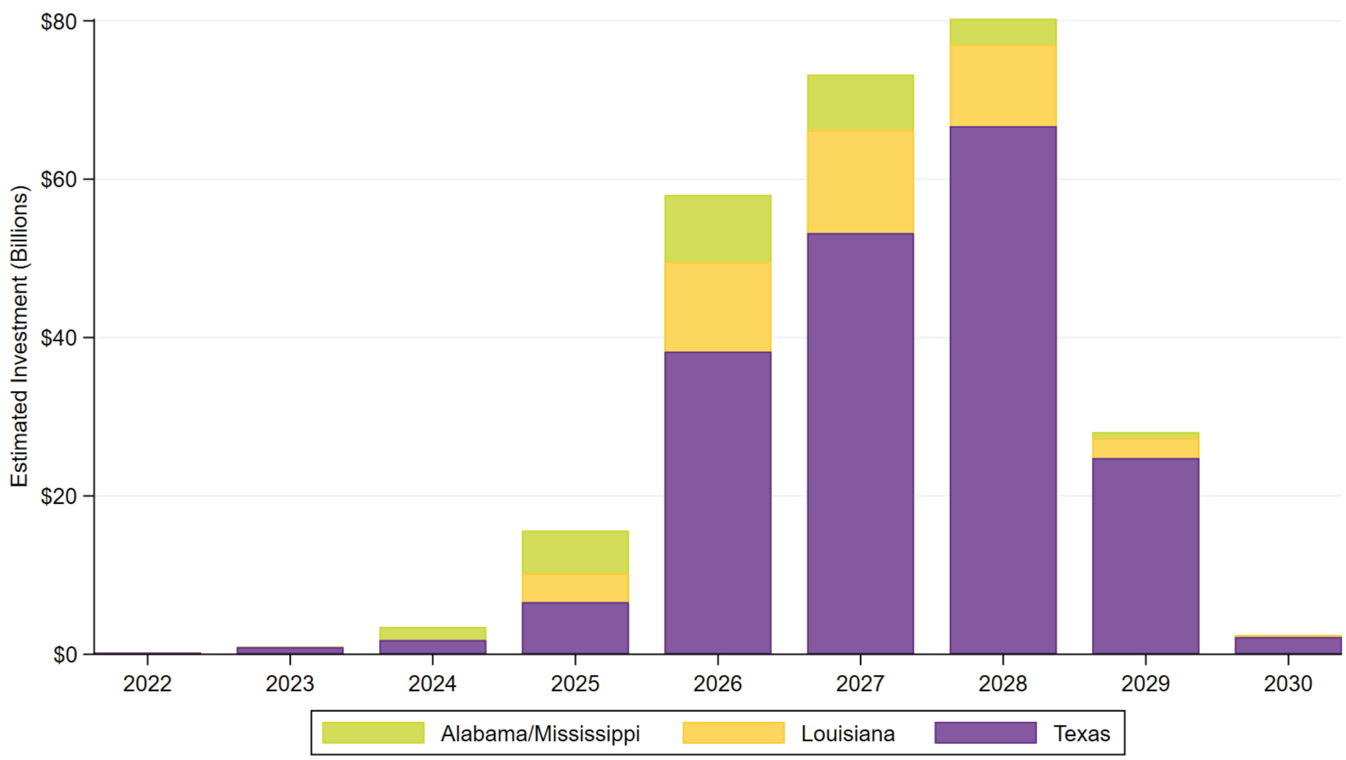
[28] Author's estimations and publicly available press releases.

Other Transition Manufacturing: Battery materials, biofuels, and synthetic-fuels facilities continue to surface across the corridor. Most projects proceed in staged modules that calibrate to market off-take opportunities and credit/finance availability.

5.5 Energy-Intensive Demand Drivers: Data Centers and Steel

While not traditional "energy manufacturing," data centers now rival mid-sized and even larger industrial loads and will materially impact regional power generation as well as natural gas delivery and storage capacity and utilization. The 2026 GCEO has identified $262 billion in regional data center investment announcements with the overwhelming majority of this ($195 billion, or 74 percent) going to Texas and a smaller but considerably large $41 billion in Louisiana. Note, these investments are not in the base GCEO outlook. If total data center investments (shown in Figure 17) were added, total regional projected investments through 2031 would increase to well over $500 billion if all projects proceed.

Figure 17: Regional data center investment



Source: NREL, Atario, and author's construct.

In addition, Louisiana is seeing a major world class, fully integrated steel facility being developed in Donaldsonville. This investment, which has been included in the earlier, baseline GCEO outlook, is anticipated to be around $5.8 billion and will include an electric arc furnace (EAF) and direct-reduced iron (DRI) mill. The facility is expected to produce about 2.7 million metric tons of steel annually[1] and is slated to begin construction in 2026, with full commercial production targeting around 2029.[2]

From an energy-infrastructure standpoint, the scale and nature of this project will place additional pressures on regional electric generation and transmission capacity as well as many aspects of central Gulf Coast's natural-gas supply chain. The host utility, Entergy Louisiana, has identified the site as "needing major transmission projects" particularly on the West Bank of the Mississippi River and in south-central Louisiana" to provide additional load serving capacity and assure system reliability/resiliency.[29]

Further, the incorporation of DRI technology (which often relies on a natural gas feedstock) suggests, at minimum, increased natural gas pipeline utilization in the region and potentially even hydrogen infrastructure since the plant's ultra-low-carbon focus (claimed to be around 70 percent lower GHG emissions than a traditional blast furnace) signals the need for some kind of additional energy transition investment.[30]

[29]Entergy Louisiana, LLC. Louisiana Integrated Resource Plan: Technical Conference Presentation – April 2023. Baton Rouge, 2023.
[30]IEA (International Energy Agency). Iron and Steel Technology Roadmap: Towards more sustainable steelmaking. Paris, 2020.

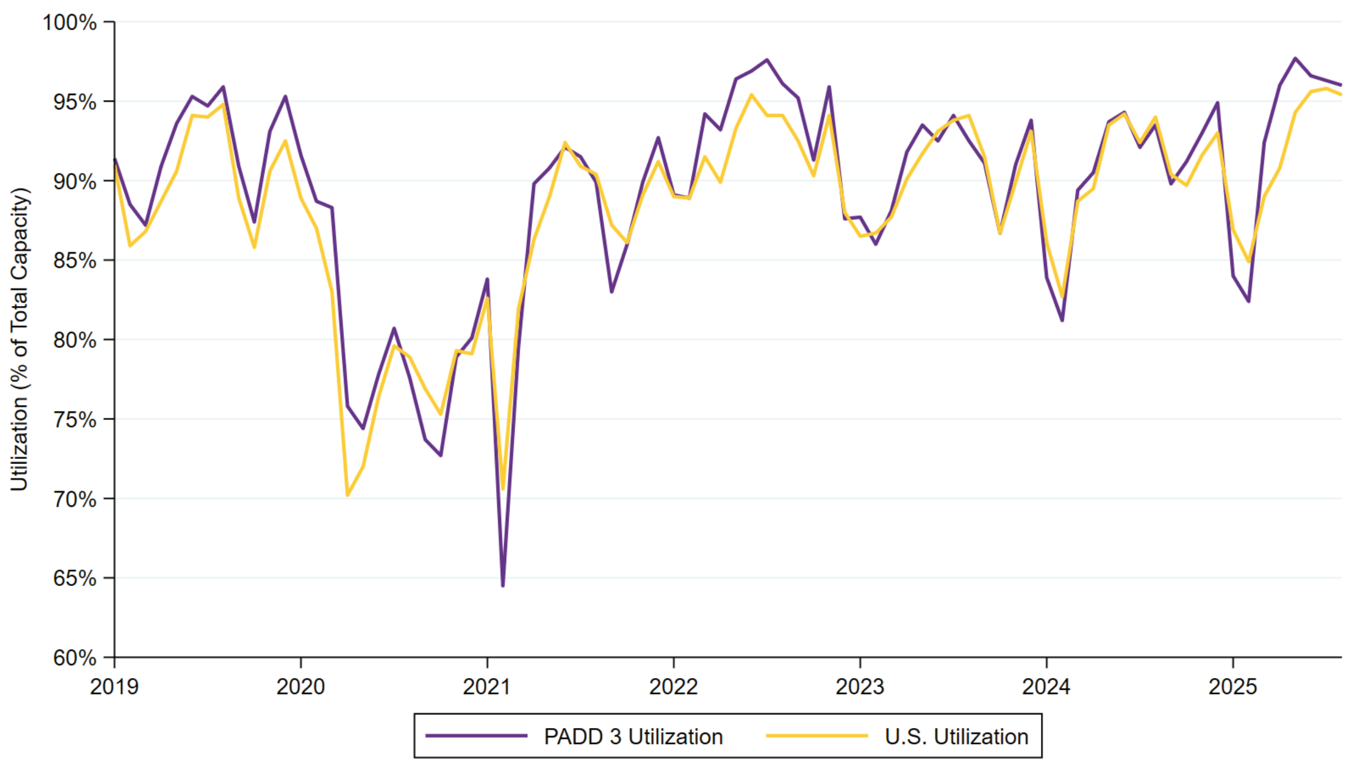
6. Energy Exports

6.1 Refined Products

Despite significant winter weather challenges at the start of 2025, the Gulf Coast region's refining sector continued to benefit from robust export opportunities arising from intensified geopolitical uncertainties, particularly the Russia-Ukraine conflict and ongoing Middle East supply disruptions. Winter Storm Enzo in January 2025 demonstrated that refineries remain vulnerable to extreme cold weather, causing utilization to drop to 79.1 percent,[31] the lowest level since 2021's Winter Storm Uri.

The refinery utilization rates recovered to above 90 percent through most of 2025, aside from the January decline. The Atlantic hurricane season produced 13 named storms as of the beginning of November 2025, which matched the low end of NOAA's 13-19 prediction. No major storms affected Texas and Louisiana thus providing operational relief during the critical summer driving season. As shown in Figure 18, this allowed Gulf Coast refineries to achieve peak utilization rates of over 97 percent in early August 2025.[32] The refinery landscape saw one significant change with LyondellBasell's completion of its planned 264,000-bpd Houston refinery closure in the first quarter of 2025.

Figure 18: U.S. and PADD 3 monthly refining utilization

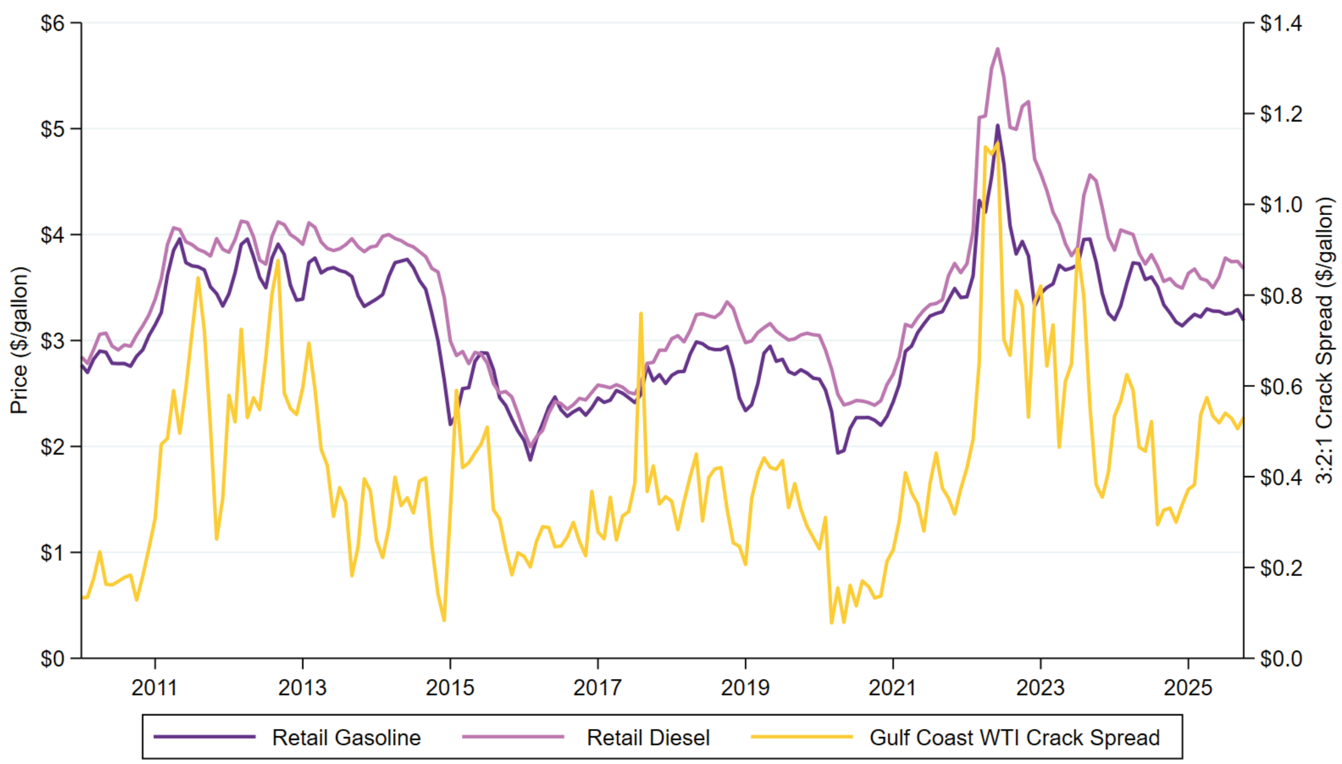


Source: U.S. Energy Information Administration. Petroleum & Other Liquids. Refinery Utilization and Capacity.

[31]Week ending January 24, 2025.
[32]Week ending August 1, 2025.

As illustrated in Figure 19, overall refining profitability has shown signs of recovery from the lows observed in late 2024, with crack spreads across major refined product types demonstrating a modest uptick. The current refining margins at $0.45/gallon in October 2025 are still significantly lower compared to the 2022 highs of $1.13/gallon. Current crack spreads indicate that while margins have normalized from crisis peaks, they continue to operate above historical averages. Retail gasoline and diesel prices have followed a similar trajectory, retreating from crisis highs while remaining elevated above historical averages.

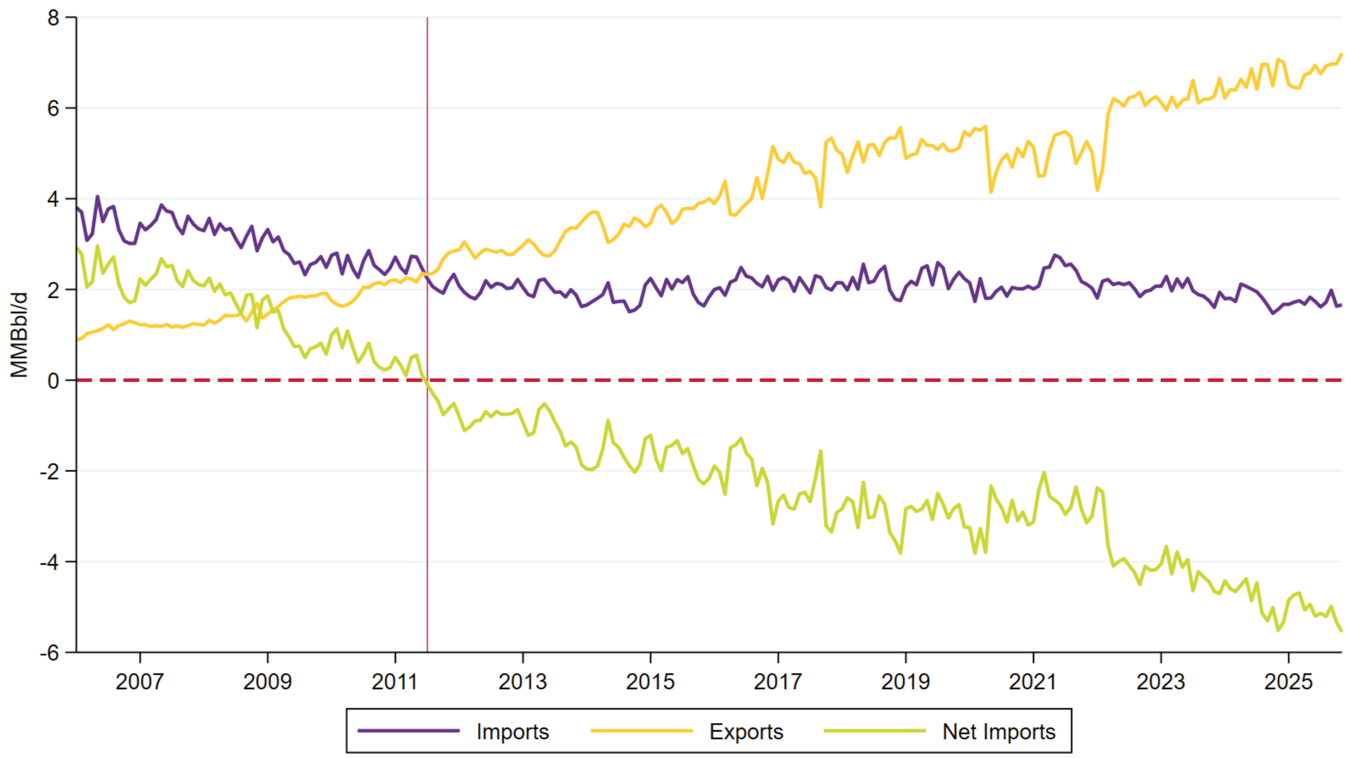
Figure 19: Retail gasoline, diesel prices, and refinery crack spread



Source: U.S. Energy Information Administration, Bloomberg Terminal, and authors' calculations. Gasoline prices are for all grades and all formulations, and diesel is based on U.S. No. 2 retail price.

As shown in Figure 20, refined product trade trends observed over the last few years' GCEO continue to strengthen as U.S. net exports grow. While imports have remained steady around 2 MMBbl/d since 2012, exports have more than doubled from 3 MMBbl/d to roughly 7 MMBbl/d, and net exports have hovered around 5 MMBbl/d in 2025. Disruptions and uncertainties in global energy markets will likely reinforce the U.S.'s export position in global markets, with potential for modest growth opportunities.

Figure 20: U.S. refined products trade

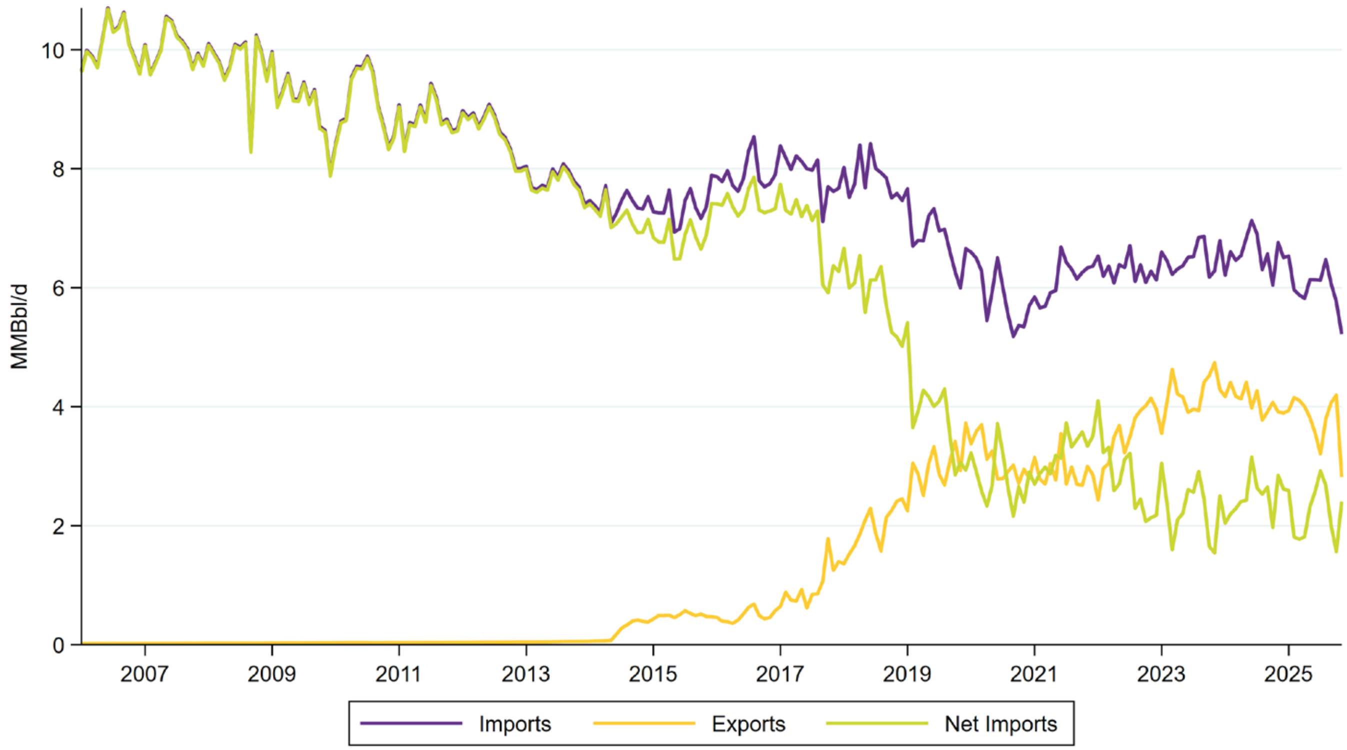


Source: U.S. Energy Information Administration.

6.2 Crude Oil

U.S. crude oil exports are shown in Figure 21. While the U.S. is still a net importer of crude oil, it has been expanding its position in global crude oil trade dating back to the middle part of the last decade, when U.S. exports surged from around six percent of total global crude oil supply, to as much as 12 to 14 percent. U.S. crude oil trade has expanded rapidly since the lifting of the oil export embargo in 2015, particularly along the Gulf Coast which accounts for almost all crude oil leaving U.S. shores. The supply sources for a good part of these crude oil exports also originate from the region, particularly the Permian Basin, and to a much lesser extent the Eagle Ford. Crude oil exports continue to grow from an average of around 3 MMbbl/d to levels that now average 4 MMbbl/d. The 2026 GCEO sees this trend continuing with 4 MMbbl/d likely being the new “floor” on overall exports levels.

Figure 21: U.S. crude oil exports and imports

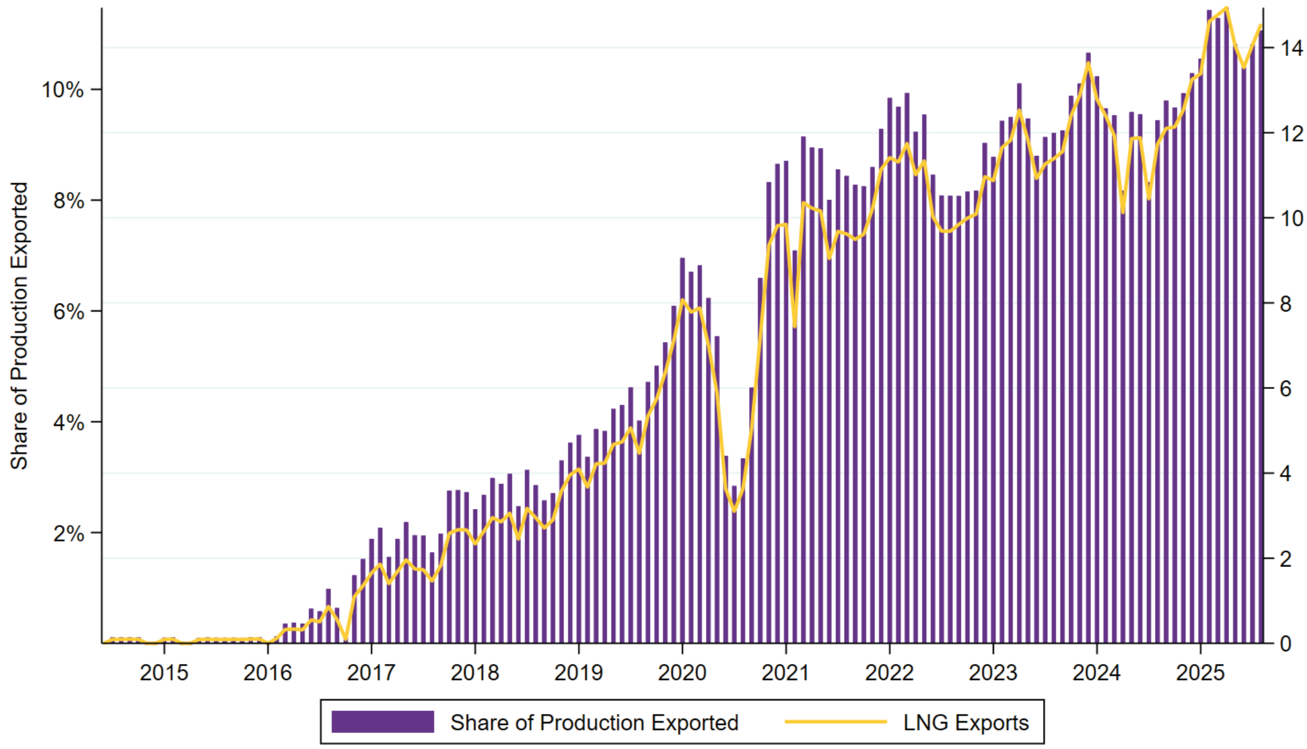


Source: U.S. Energy Information Administration. Petroleum & Other Liquids. U.S. Imports and Exports of Crude Oil.

6.3 Liquefied Natural Gas Exports

Global LNG trade has benefited considerably from recent geopolitical uncertainties, particularly the Russia-Ukraine conflict and the Middle East tensions. Natural gas volumes leaving U.S. shores have reached record levels in 2025, with LNG exports averaging over 14 Bcf/d, making the U.S. the world's leading exporter. However, events over the last four years (2022-2025, inclusive) have shown how vulnerable these export volumes can be to capacity availability. In June 2022, for instance, Freeport LNG in Texas, the second largest export facility along the Gulf Coast at 2 billion cubic feet per day (Bcf/d), experienced a fire, shutting down the facility for nearly a year. As shown in Figure 22, an unplanned outage at the same facility in January 2024 followed by reduced capacity because of maintenance work shows the significant impact of these outages on export volumes.

Figure 22: U.S. liquefied natural gas exports



Source: U.S. Energy Information Administration.

As shown in Figure 22, U.S. LNG exports have reached unprecedented levels, with significant contributions from newly operational facilities. Plaquemines LNG Phase 1 began commissioning and shipped its first cargo in late 2024, while Phase 2 remains under construction targeting September 2025 startup. In February 2025, Corpus Christi Stage 3 produced its first LNG cargo and entered commissioning. The regulatory environment has shifted decisively toward expansion, contrasting sharply with the previous administration's approach. President Trump lifted the pause on new LNG export project approvals to non-FTA countries on his first day in office, enabling renewed momentum for stalled projects. Projects currently under construction include Golden Pass LNG (2.04 Bcf/d across three trains targeting 2026-2027), Port Arthur LNG Phase 1 (1.58 Bcf/d targeting 2027), Rio Grande LNG Phase 1 (2.16 Bcf/d across three trains targeting 2027-2028), and Woodside Louisiana LNG Phase 1 (0.73 Bcf/d targeting H2 2029). These projects under construction represent approximately 7.83 Bcf/d of additional capacity. Beyond construction projects, 16 FERC-approved projects await FIDs, representing 26.5 Bcf/d of potential capacity.

The first half of 2025 saw continued shifts in U.S. LNG export patterns, with increased European consumption, primarily driven by the electricity sector amid lower renewable generation from wind and hydro. The expiration of the Russia-Ukraine gas transit agreement on January 1, 2025, eliminated approximately 530 bcf of Russian pipeline gas to Europe. Meanwhile, the Trump administration has actively promoted U.S. LNG exports globally, including a July 2025 trade agreement in which the EU pledged $750 billion in total energy purchases (including LNG, oil, and nuclear) from the U.S. over three years, though analysts consider this target challenging to achieve.

7. State and Federal Policy Implications on Gulf Coast Energy

7.1 State Policy Implications

The Gulf Coast energy sector operates within a policy environment shaped by both federal and state actions. Over the past several years, stakeholders have indicated that shifts in policy priorities across administrations—at both levels of government—have occurred more frequently and with greater magnitude than in previous decades. These shifts include changes to federal tax credits, trade policies, and regulatory guidance, as well as adjustments in state-level governance following transitions in elected leadership, including the inauguration of Governor Jeff Landry in January 2024.

According to some industry participants, the cumulative effect of these federal and state changes has contributed to elevated uncertainty regarding long-term investment planning. Stakeholders note that the timing and direction of policy signals can influence decisions related to refinery operations, LNG development, industrial expansions, and infrastructure investment across Louisiana and the broader Gulf Coast.

As a result, firms operating in the region continue to monitor evolving federal and state policy landscapes closely, emphasizing the importance of regulatory clarity and stability for long-term capital deployment.

7.1.1 Louisiana's Exposure to Shifts in Energy Policy

Louisiana's economy has long been connected to energy production, processing, and exports. In 2024, the state exported approximately $87 billion in goods—about 28 percent of its total economic output—with petroleum and chemical products accounting for more than half of this value. Because of this concentration, stakeholders note that changes in national policy—including adjustments to export permitting, federal tax incentives, and trade measures—are felt quickly in Louisiana's industrial corridor. Contractors in areas such as Geismar may experience shifts in workload earlier than national indicators reflect, and changes in operating schedules can affect shift workers before broader economic trends are formally captured in forecasts.

Stakeholders also emphasize that uncertainty surrounding policy direction can influence the timing of capital decisions. In some cases, firms report delaying planned maintenance, reevaluating project timelines, or considering alternative locations for new investments.

7.1.2 A State Assessing its Policy Direction

Recent changes in state leadership have coincided with efforts to adjust Louisiana's energy and industrial policy framework. Several policy actions during the past year have focused on tax structures, permitting processes, and the regulation of emerging technologies. For example, the state has enacted adjustments to severance and royalty provisions, including a scheduled reduction of the oil severance tax rate on new wells to 6.5 percent and modifications to the Royalty Reduction Program intended to support continued exploration activity. In addition, Executive Order JML 25-033 revised aspects of the Industrial Tax Exemption Program (ITEP), altering approval timelines and establishing an expedited process for large-scale projects.

Legislative activity has also addressed carbon management and related infrastructure. Multiple measures have increased landowner consent requirements for carbon storage and introduced additional oversight for pipeline rights-of-way. A temporary pause on new Class VI well applications was implemented in October 2025 to allow state agencies time to update administrative procedures.

While these changes represent a notable level of policy development, stakeholders have indicated that questions remain about the state's long-term policy trajectory. Some industry representatives have expressed uncertainty about the pace at which agencies can implement recent reforms, while others point to leadership transitions and staffing changes as contributing to a sense of evolving priorities. As a result, many observers continue to monitor how these adjustments will influence investment decisions and regulatory expectations in the years ahead.

7.1.3 Act 458: A New Administrative Framework for Energy Governance

Within the broader context of shifting federal and state policy environments, Act 458 of 2025 represents a notable restructuring of Louisiana's energy and natural-resource governance. The legislation consolidates several previously separate offices into a single Department of Conservation and Energy (C&E), with the intent of streamlining oversight, administrative processes, and coordination across permitting, enforcement, resource management, and energy-related activities.

Under the new framework, seven offices—including Permitting and Compliance, Enforcement, State Resources, Energy, the Secretary's Office, the Natural Resources Commission, and Administration—now operate within a unified departmental structure. Stakeholders have indicated that this consolidated approach may offer clearer lines of responsibility and improve the consistency of regulatory processes, particularly by differentiating administrative, policy, and regulatory functions.

Act 458 also establishes a certification process for partnerships, pilot initiatives, and research collaborations. The intent of this process is to introduce transparent criteria related to fiscal considerations, public benefit, and program alignment, thereby providing a standardized method for evaluating a broad range of energy-related projects. Stakeholders note that this mechanism may help organize the state's approach to emerging technologies, including hydrogen and carbon management.

Efforts to modernize internal systems are underway within the new department, including updates to digital permitting platforms, improvements in data sharing across offices, and development of performance-tracking tools. While these initiatives remain in early stages, they reflect an emphasis on administrative capacity and operational reliability, areas that industry and local governments have long identified as important for regulatory clarity and long-term planning.

7.2 Federal Policy Implications on Gulf Coast Energy

In recent years, federal policy has reshaped the U.S. energy landscape in increasingly dramatic ways relative to historical administrative changes. Shifting energy ideologies, political polarization, and evolving federal investment tools have produced significant swings between favoring conventional and renewable energy sources. Over the past nine years, the U.S. has undergone three presidential transitions—each representing different energy priorities than the one before. As shown in the

International Energy Agency's (IEA) World Energy Outlook 2025, these policy shifts influence global markets as well. Earlier IEA projections anticipated a peak in global oil demand around 2030, but updated assessments now highlight a growing and persistent role for conventional fuels through mid-century.

7.2.1 Biden Administration

The 2021 Infrastructure Investment and Jobs Act (IIJA) provided more than $70 billion for electrical grid investments, energy efficiency programs, and clean energy initiatives. Some estimates placed the total impact of the 2022 IRA energy provisions in the trillions of dollars. These were key pillars of the Biden administration's energy strategy. That administration also emphasized consumer adoption of electrification and EVs, while holding only three offshore oil and gas lease sales—all in the Gulf of America—the fewest under any administration since federal offshore leasing began.

Additionally, the administration imposed a moratorium on exports of LNG to countries without free trade agreements with the U.S.

7.2.2 Trump Administration

By contrast, the first Trump administration's offshore leasing plan called for 47 lease sales, and the current administration proposes 30. Billions in grants and subsidies under the IIJA and IRA have been paused or rescinded, including the $156 million "Solar for Y'all" program intended to expand rooftop solar access in low-income Louisiana communities. Recent statutory changes enacted in 2025 sunset the EV tax incentive at the end of September 2025 and alter the timing and eligibility criteria for other IRA clean energy credits, restore intangible drilling cost deductions, reduce royalty rates for federal onshore and offshore energy leases, and introduce additional incentives to stimulate investment in domestic energy production.

An executive order signed on the first day of the new administration repealed the LNG export moratorium. Reflecting the impact of that repeal, energy outlooks published this year by both the IEA and the U.S. Energy Information Administration (EIA) project the U.S. as a dominant global supplier of LNG. The EIA estimates that U.S. LNG exports will more than double by 2037, with nearly all new export capacity located on the Gulf Coast.

In February 2025, President Donald Trump signed an executive order establishing the National Energy Dominance Council to promote domestic energy development, regulatory efficiency, job creation, a critical-minerals strategy, lower energy prices, and expanded energy exports. This new White House office coordinates policies across multiple agencies with the goal of accelerating the administration's energy agenda.

7.2.3 Shifting Policy Priorities While Markets Look for Certainty

In summary, the Biden administration prioritized an "energy transition" centered on renewable energy and electrification, while the Trump administration emphasizes "energy dominance"—a source-neutral approach aimed at maximizing domestic production and export strength. For the Gulf Coast, this policy shift creates a largely favorable environment for traditional energy and export sectors, but also introduces uncertainty for low-carbon infrastructure and some renewable-energy projects.

7.2.4 Other Variables – Growing Demands and Shifting Global Markets

Additional variables with the potential to significantly affect domestic and global energy markets include the accelerating electricity needs of data centers and the evolving Russia-Ukraine conflict. In recent years, U.S. electricity generation has remained relatively stagnant consistent with overall U.S. electricity usage growth of less than 1 percent annually. With projected growth in artificial intelligence and cloud computing, some projections estimate that data centers could account for more than 10 percent of national electricity consumption by 2030, up from less than 5 percent today. Most new data center electricity demand in the U.S. is expected to be met by natural gas-fired generation, though the IEA anticipates a larger role for renewable energy over time.

The recently announced $27 billion Meta Hyperion data center campus in Richland Parish, Louisiana, for example, will include three natural gas-fired generation facilities (two located near the site and one in southeast Louisiana) being constructed by Entergy Louisiana along with approximately 500 MW of solar PV farms to provide electricity and renewable energy credits (RECs) to its four-million-square-foot footprint. The Trump administration's AI Action Plan outlines numerous initiatives to strengthen U.S. leadership in artificial intelligence, including prioritizing energy infrastructure needed to support data center growth. Louisiana now has two new data-center projects announced or under construction. The state's abundant energy resources, available land and water, and welcoming business climate will continue to attract investment.

The effects of Russia's invasion of Ukraine have also been profound and will continue to evolve. As recently as 2021, Russia was the world's largest exporter of natural gas and the second-largest exporter of crude oil and condensates. Nearly 75 percent of its natural gas exports, amounting to 6.5 trillion cubic feet annually, went to European countries. Multilateral sanctions, embargoes, and price caps from the U.S., European Union, G7, and others have redrawn global energy flows.

LNG exports from Louisiana have helped fill the gap left by reduced Russian supplies to Europe. Billions of barrels of Russian oil and trillions of cubic feet of natural gas are currently subject to sanctions. As recently as October 22, 2025, the U.S. Department of the Treasury imposed new sanctions on Rosneft and Lukoil, Russia's two largest oil companies. The result has been a massive global energy void—one in which the Gulf Coast's infrastructure and export capacity have played a critical role. Should a peace agreement be reached and sanctions relaxed, global markets will shift yet again.

8. Employment Outlook

8.1 Employment Forecasts

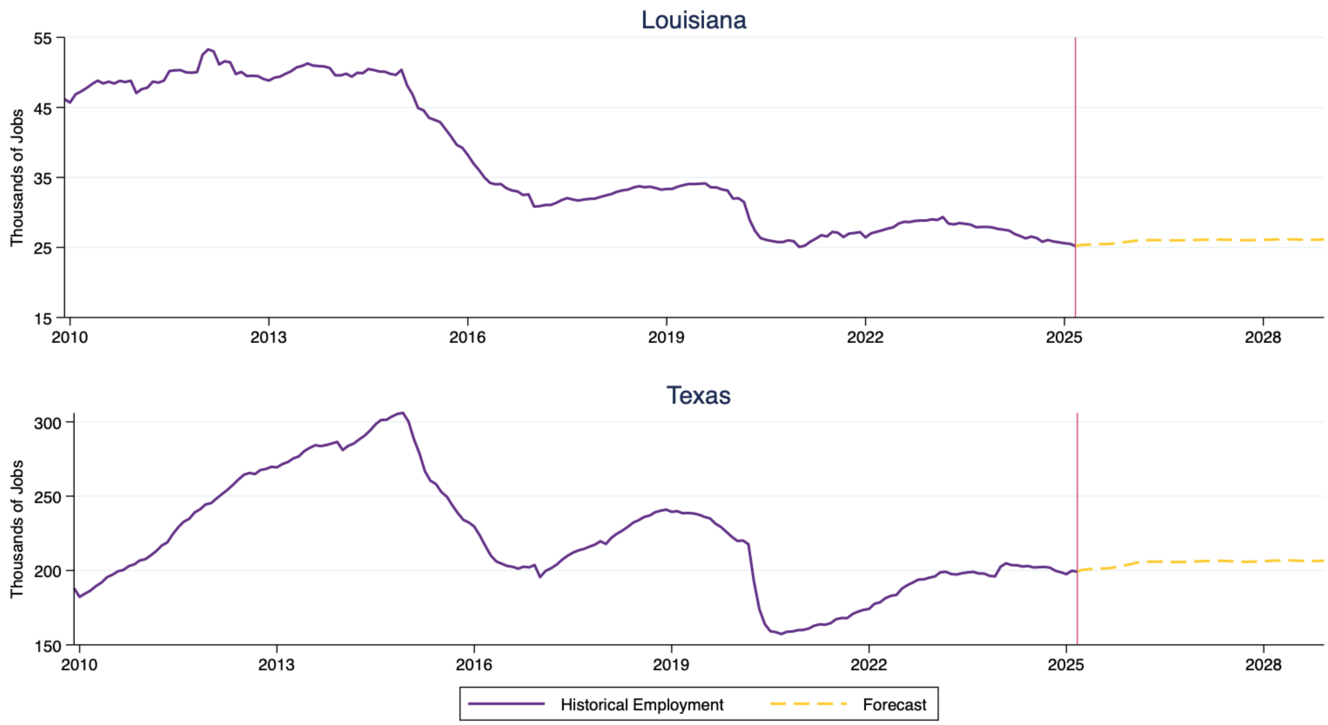
In this final section of the GCEO, prior sections are synthesized into employment forecasts. Employment is forecast within two broad sectors: (1) upstream oil and gas extraction and services and (2) refining and chemical manufacturing. Sectors are identified based on the North American Industry Classification System (NAICS). Upstream oil and gas is defined as including oil and gas extraction (NAICS sector 211) and support activities for mining (NAICS sector 213). Refining and chemical manufacturing employment includes petroleum and coal products manufacturing (NAICS sector 324) and chemical manufacturing (NAICS sector 325).[33] Employment forecasts are produced for each of these aggregated sectors for Texas and Louisiana. Note that recent historical data is subject to future revisions by the U.S. Bureau of Labor Statistics (BLS). Also note that each data series comes out with a lag. The most recent month of complete data available is March 2025 for both upstream and downstream employment. Thus, part of the "forecast" has already occurred; we just have not observed the labor market data. Please also note that past data is revised, and so historical observations themselves can change as revisions become available.

Upstream oil and gas employment for both Louisiana and Texas exhibit three key patterns in historical data shown in Figure 23. The first key pattern is that Louisiana employment growth, pre-2015, was modest relative to the rapid growth in Texas employment. Both states, however, saw a collapse in upstream employment in 2015, when crude oil prices also collapsed, as did rig counts (see Figure 2 in Section 2.1). During the 2015 crash, Texas lost more than 100,000 upstream jobs from peak to trough. Louisiana lost about 18,000 over the same period. After the 2015 crash, Texas employment climbed back slowly through approximately the end of 2018 before beginning a modest decline. Louisiana upstream employment was approximately flat over this same period.

The next event began in early 2020 in response to the COVID-induced economic downturn. Comparing the peak employment experienced in 2019 relative to the post COVID-trough, Louisiana lost ~9,000 jobs in total while Texas lost ~83,000 jobs. On a percentage basis, Louisiana and Texas lost 27 percent and 34 percent, respectively. Thus, not only did Texas lose more jobs, but it also experienced a larger percentage drop relative to Louisiana. As of the most recent estimates (March 2025), the employment levels are still almost 26 percent lower than the pre-pandemic peak in Louisiana and about 17 percent below in Texas, even after regaining roughly 2,400 jobs in Louisiana and 45,000 jobs in Texas since the COVID downturn.

[33] Chemical manufacturing includes many product types, including resins, pesticides, pharmaceuticals, paints, soaps, and others.

Figure 23: Upstream employment forecast



Source: U.S. Bureau of Labor Statistics, Current Employment Statistics. Authors' forecast.

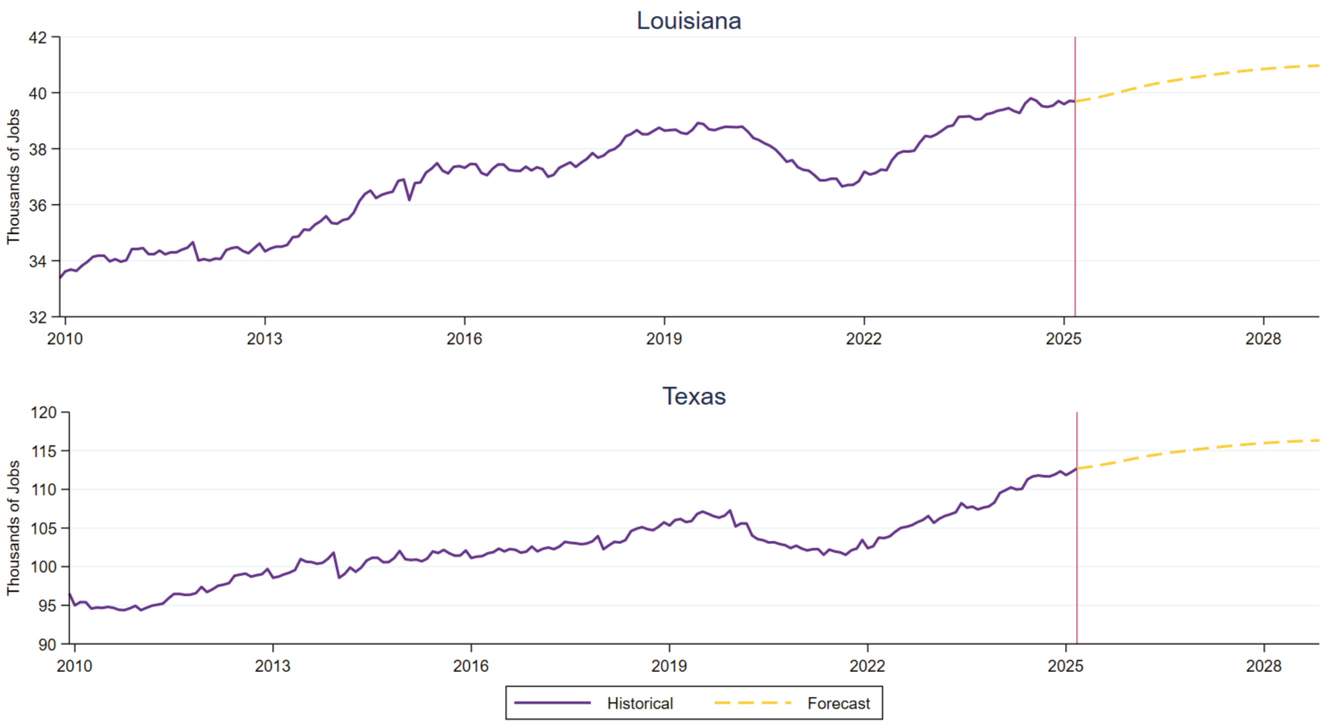
Figure 23 also shows the forecasted employment in the upstream oil and gas sectors for Louisiana and Texas, respectively. Econometric forecasts are based on a combination of the futures markets for oil and natural gas shown in Figure 5 alongside the AEO model outputs shown in Figure 6 (Section 2.3).

Overall, Louisiana upstream oil and gas employment is forecasted to remain relatively stable through the forecast horizon ending in 2028, with only modest gains over time. From January to March 2025, current employment data suggests that the sector lost approximately 400 jobs, or a 1.6 percent decline. The forecast suggests that employment will increase gradually through about the second quarter of 2025 before leveling off, maintaining a steady trend through the end of the forecast horizon. This is due to the lagged effect of production and prices in coming months. But because prices are in backwardation for both oil and gas, this is anticipated to then lead to a flattening and ultimately slowing of employment through the end of the forecast horizon at the end of 2028. Employment at the end of the forecast horizon (December 2028) is about 900 jobs higher than the most recent month of data available (March 2025). Thus, while the forecast shows ups and downs empirically, we interpret this as a relatively flat employment forecast for upstream oil and gas employment in Louisiana through the forecast horizon.

Estimated Texas upstream oil and gas employment has grown modestly in 2025 thus far, adding about 1,700 jobs, or roughly 0.9 percent. The forecast anticipates continued gradual growth through 2026, followed by a period of relative stability with only minor fluctuations through 2028. Even with these seasonal fluctuations, employment at the end of the forecast horizon (December 2028) is projected to be about 7,000 jobs higher than the most recent month of data available (March 2025). This empirical result is consistent with conversations with industry, who broadly indicate that the anticipation is to gradually grow production through efficiency gains.

Note that oil and gas production in the Gulf Coast region is anticipated to continue to increase through the forecast horizon while the Texas and Louisiana upstream employment forecasts show only modest gains. This illustrates the continued expected efficiency improvement of the sector.

Figure 24: Refining and chemical manufacturing employment forecast



Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, ITEP, and Authors' forecast.

Historical data on refining and chemical manufacturing employment are shown in Figure 24. Both states exhibit two notable trends. First, pre-COVID, both states experienced approximately a decade of growth in these sectors. As discussed throughout, GCEO attributes this employment growth to the investment in these sectors that has facilitated the exporting of products around the globe. Second, both states experienced reductions in refining and chemical manufacturing employment due to the COVID-induced recession, but these employment losses were not as large, both in terms of total numbers and as a share of employment, as experienced in the upstream sector (or the economy overall). From peak to trough, Louisiana and Texas lost approximately 2,300 and 5,700 refining and chemical manufacturing jobs, respectively. This is about a 5-to-6 percent reduction in both states (compared to more than 25 percent job losses in upstream employment in each state).

Figure 24 also shows the forecasted employment in the refining and chemical manufacturing sectors. For both Louisiana and Texas, the GCEO forecast is based on the historical relationship between capital expenditures and employment growth alongside our baseline capital expenditures presented in Section 5.

For Louisiana, GCEO anticipates that refining and chemical manufacturing employment will continue its slight upward trajectory in the near-term from sustained investments and industry activity. The sector first surpassed the 2019 benchmark as early as June 2023. In 2025, employment is projected to increase by roughly 370 jobs, or 0.9 percent. By year-end 2025, total employment is forecasted to reach about 40,100, approximately 1,150 jobs higher than the previous record. Looking forward, annual growth rates of 0.4 to 1.2 percent are expected through 2028, signaling steady expansion, though at a moderating pace compared to recent years.

Texas refining and chemical manufacturing employment shows a similar trend. In 2025, Texas is forecasted to gain around 1,450 jobs, representing a 1.3 percent increase and bringing the workforce to nearly 6,500 above the 2019 peak. Job gains are expected to continue, with about 1,300 jobs added in 2026, 835 in 2027, and 400 in 2028, reflecting sustained but slowing growth.

9. Conclusion

The 2026 Gulf Coast Energy Outlook reflects a region navigating an intersection of market fundamentals, technological progress, shifting policy landscapes, and rapidly evolving global demand. Across every segment of the energy value chain—from upstream production to industrial manufacturing, electricity markets, and export activity—the Gulf Coast remains central to the nation's energy economy. Yet this year's analysis underscores a common theme echoed by industry stakeholders: the fundamentals remain strong, but the environment surrounding them is increasingly uncertain.

Crude oil and natural gas production throughout the Gulf Coast continues to expand, driven not by increased drilling activity but by consistent efficiency gains and technological improvements. These advances reaffirm a decade-long trend: production growth is increasingly decoupled from rig counts and workforce size. Modeling suggests both oil and natural gas output will rise steadily through the early 2030s, providing a stable foundation for downstream and export sectors.

The region's comparative advantage in natural gas pricing—particularly relative to Europe and Asia—continues to support petrochemicals, LNG projects, and energy-intensive manufacturing. Meanwhile, electricity markets are undergoing an inflection point. After two decades of flat demand, load growth is returning, led by industrial expansions, electrification, and a surge of interest in large-scale data centers. Maintaining the region's historically low electricity prices will require continued planning around resource adequacy and infrastructure.

The Gulf Coast's energy manufacturing sector continues to evolve. LNG remains the marquee investment class, while petrochemicals are increasingly emphasizing smaller-scale efficiency upgrades. Transition-related investments—clean hydrogen, ammonia, CCS, and biofuels—now account for a substantial share of regional announcements, though developers emphasize the importance of federal guidance, tax credit eligibility, and permitting timelines.

Data centers and new industrial loads, including the Hyundai steel facility, represent an emerging energy-intensive dimension. Their scale materially affects regional electricity and natural gas infrastructure, reinforcing the Gulf Coast's role as a hub for sectors relying on abundant, affordable power.

Refined product exports remain robust, crude oil exports continue at historic highs, and the U.S. is the world's largest LNG exporter—with new capacity concentrated along the Gulf Coast. However, trade policies, tariffs, and FEOC restrictions introduce cost uncertainty into major capital projects, even as global demand continues to create opportunity.

Policy swings—both federal and state—now play a disproportionately large role in investment decisions. The past decade has featured three different federal energy strategies, each reshaping incentives, permitting, and market expectations. Louisiana's own restructuring under Act 458 aims to modernize governance but adds near-term process adjustments for developers.

The Gulf Coast remains uniquely positioned to lead the nation in LNG exports, petrochemical production, industrial growth, and emerging transition technologies. Yet the region's outlook will depend on how effectively it navigates three central uncertainties: policy direction, global market dynamics, and the pace of electricity demand growth.

The Center for Energy Studies

The Center for Energy Studies conducts, encourages, and facilitates research and analysis to address energy-related problems or issues affecting Louisiana's economy, environment, and citizenry. The Center's goal is to provide a balanced, objective, and timely treatment of issues with potentially important consequences for Louisiana.

The Center for Energy Studies was created by the Louisiana Legislature in 1982 as the embodiment of recommendations made by an independent group of experts and at the urging of Louisiana business and public interest groups, as well as the University.

lsu.edu/ces

The LSU Energy Institute

The LSU Energy Institute unites the university's established strengths in energy research under one umbrella. By bringing together the Center for Energy Studies, the Louisiana Geological Survey, and LSU's broader energy innovation research programs, the Institute provides a comprehensive, interdisciplinary hub for energy scholarship and engagement.

From policy and economics to geology and engineering, LSU researchers are working across disciplines to address Louisiana's most pressing energy challenges and contribute to national and global conversations about the future of energy.

lsu.edu/energy

LSU | Center for Energy Studies

LSU | Energy Institute