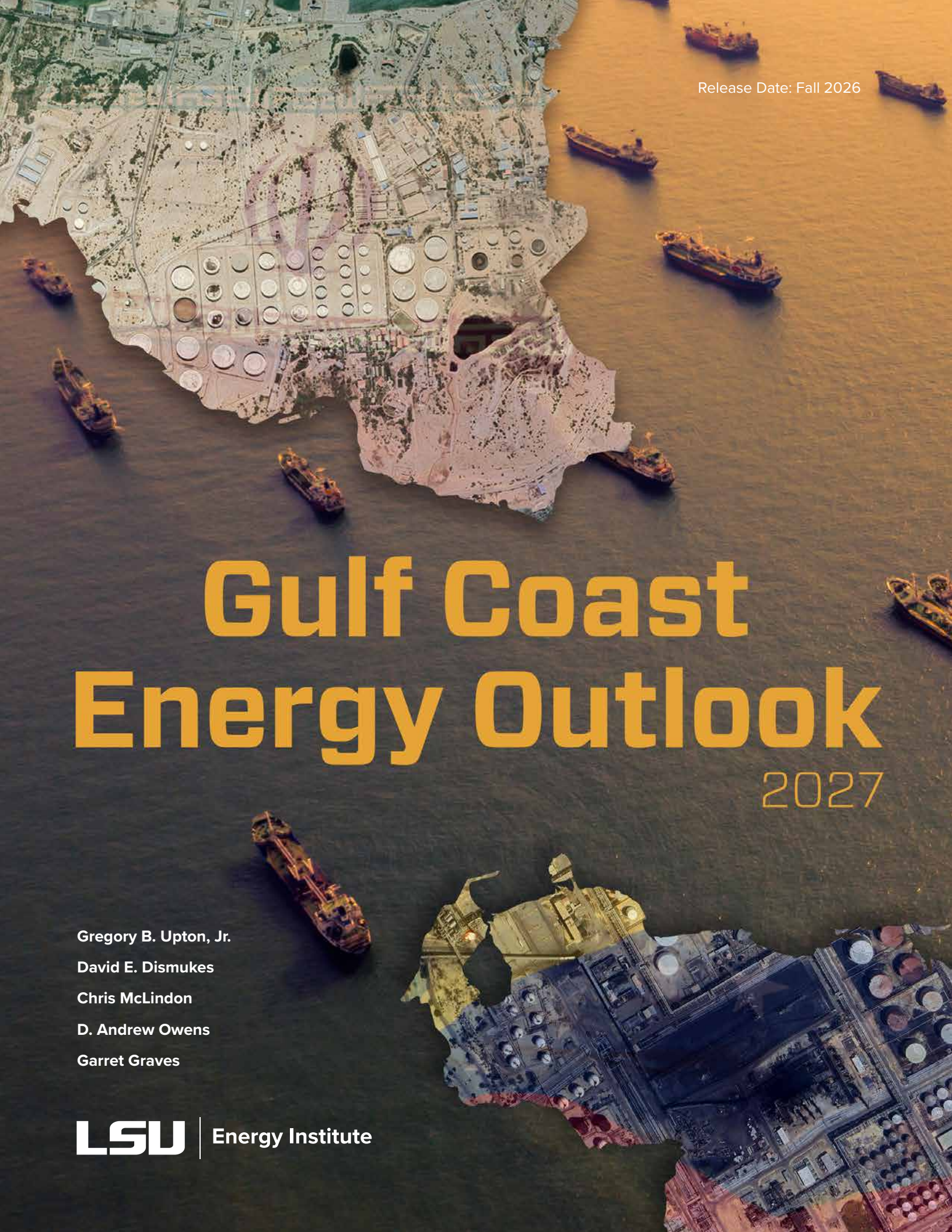

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Gulf Coast Energy Outlook 2027

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LSU | Energy Institute

2027 Gulf Coast Energy Outlook

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This report includes contributions from multiple authors. The views and opinions expressed are those of the respective authors and do not necessarily reflect the official position of Louisiana State University. Authors may differ in their interpretations and conclusions; inclusion in this report does not imply agreement among all contributors.

1. Introduction

The annual *Gulf Coast Energy Outlook* (GCEO) provides stakeholders with an overview of current trends and expectations for the region's energy industry. The GCEO is a work product of the Energy Institute at Louisiana State University (EI), formerly the Center for Energy Studies (CES). The institute's transition to EI reflects an expanded scope while continuing CES's longstanding work in energy research, analysis, and public engagement.

EI research is supported by the institute's state appropriation, underscoring Louisiana's commitment to independent, data-driven energy analysis. EI is also grateful for its sustaining members who make annual contributions to the Robert H. Baumann endowment, whose support helps make possible the dissemination of timely information and analysis on issues affecting the Gulf Coast economy, environment, and citizenry.

Unless otherwise stated, the "Gulf Coast" region refers to Texas, Louisiana, Mississippi, and Alabama. In some instances, U.S. Department of Energy reporting conventions require data at the Petroleum Administration for Defense District 3 (PADD 3) level, which also includes Arkansas and New Mexico. Employment forecasts primarily focus on Louisiana and Texas. The forecast horizon generally extends through 2029, or approximately three years.

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

1.1 Geopolitics

Readers are likely not surprised that geopolitical events were the largest focal point in energy markets this past year. Geopolitical events and the resulting uncertainty can have significant implications for energy prices, particularly for crude oil and natural gas, which are traded globally. Conflicts involving major producing regions, transportation corridors, or trading partners can affect both realized energy supplies and expectations regarding future supply availability. As a result, prices may respond not only to physical disruptions, but also to changes in the perceived likelihood, duration, and magnitude of future disruptions.

The Russian invasion of Ukraine in early 2022 demonstrated the potential magnitude of these effects. Following the invasion, inflation-adjusted West Texas Intermediate (WTI) spot prices reached a peak of $141 per barrel, while Brent reached $152 per barrel as markets responded to sanctions, uncertainty regarding Russian exports, and concerns about the stability of global energy trade.[1] For comparison, the conflict involving the United States, Israel, and Iran and the disruption of traffic through the Strait of Hormuz caused inflation-adjusted WTI prices to reach $114 per barrel and Brent prices to reach $138 per barrel. Although the Strait of Hormuz is one of the world's most important energy transit corridors, the initial price response was smaller than the response following the Russian invasion of Ukraine.

Global natural gas prices also increased in response to these events. Again, comparing the Russia–Ukraine and Iran conflicts, Title Transfer Facility (TTF) inflation-adjusted monthly spot prices exceeded $78 per million British thermal units (MMBtu) in August 2022 following the Russian invasion of Ukraine and surpassed $17 per MMBtu in March 2026 following Operation Epic Fury in the Middle East. Japan Korea Marker (JKM) prices exhibited a similar pattern, exceeding $60 per MMBtu in August 2022 and $20 per MMBtu in March 2026. Henry Hub also reached $11 per MMBtu in August 2022 following the invasion earlier that year. In contrast, Henry Hub prices exhibited no comparable increase in response to

[1] Prices are daily spot prices adjusted for inflation to July 2026 dollars using the Personal Consumption Expenditures (PCE) Price Index.

Operation Epic Fury, suggesting that the U.S. natural gas market remained relatively insulated from the immediate effects of disruptions in global natural gas supply.

At the time of writing, the conflict with Iran remains ongoing. Renewed attacks on shipping and energy infrastructure contributed to WTI again exceeding $110 and Brent prices exceeding $129 per barrel in October 2026. The renewed increase occurred approximately eight months after the conflict began and followed continued restrictions on oil movements through the Strait of Hormuz. Thus, the duration of the conflict, the availability of alternative transportation routes, and the ability of other producers to offset disrupted supply remain important sources of uncertainty for the outlook.

Developments in Venezuela could in theory partially offset reductions in oil supply elsewhere, although the timing and magnitude of production increases remain uncertain, and thus GCEO views it as unlikely Venezuelan production growth will have a meaningful impact on global prices during the forecast horizon. Venezuela's oil production has declined substantially from its historical peak in 1970[2] following years of underinvestment, operational deterioration, sanctions, and changes in the legal treatment of foreign investment. Beginning in 2026, the United States eased restrictions on petroleum-sector activity, while Venezuela revised its hydrocarbons framework to provide foreign firms with greater operational control and more flexible commercial arrangements.

Several companies have subsequently announced plans to expand Venezuelan production. Chevron's Venezuelan joint ventures plan to invest more than $7 billion over five years and increase production to approximately 600,000 barrels per day by 2031. Separately, Eni has entered into a 25-year production-sharing agreement covering the Junín-5 field and has stated a target of producing approximately 400,000 barrels per day from its Venezuelan oil projects by the end of the decade.[3] Additionally, Repsol announced plans to increase gross Venezuelan oil production by approximately 50 percent within 12 months and to triple production within three years.[4]

These company announcements form part of a broader effort to increase investment in Venezuela's petroleum sector. An agreement announced in August 2026 covers 17 oil fields in the Lake Maracaibo region and Orinoco Belt and has been associated with discussions of approximately $100 billion in investment.[5] According to the White House, these fields contain approximately 65 billion barrels of proven oil reserves.

The announced investments are particularly relevant to the Gulf Coast because Venezuelan heavy crude is well suited to many of the region's complex refineries. Increased Venezuelan production could expand the availability of heavy crude oil to Gulf Coast refiners and alter regional crude-import patterns. However, the production targets depend on sustained investment, the rehabilitation of existing infrastructure, access to equipment and diluent, stable contractual arrangements, and continued authorization under U.S. sanctions policy. Consequently, announced investment and production targets should not be interpreted as certain.

Geopolitical developments are therefore expected to remain a significant source of uncertainty for energy markets. The effects of the continuing conflict with Iran will depend on its duration, the availability of alternative supply routes, the use of strategic petroleum reserves, and the ability of producers and consumers to adjust to disrupted trade patterns. At the same time, the extent to which additional

[2] Venezuela's crude oil production peaked at approximately 3.7 million barrels per day in 1970 (7.8 percent of global production), compared with an estimated 1.1 million barrels per day in 2025 (1.1 percent of global production).

[3] Marianna Parraga and Sheila Dang, "Chevron Expands Venezuela Presence with $7 Billion Plan to Double Oil Output in Five Years," *Reuters*, September 2, 2026.

[4] Repsol, "Repsol Agrees on Conditions to Increase Its Oil Production in Venezuela," press release, April 16, 2026.

[5] The White House, "Fact Sheet: President Donald J. Trump Announces Historic Oil Agreement to Secure American Energy Dominance and Drive Venezuela's Economic Recovery," August 31, 2026.

Venezuelan production reaches the market will depend on whether recently announced agreements result in sustained capital investment and increased field-level output.

This year's GCEO assumes that conflict in the Middle East gradually attenuates, and that global markets make gradual adjustments to accommodate this increased risk. Markets will continue to be in backwardation and, over the course of the forecast horizon, will converge back to long-run equilibrium.

1.2 Electricity Demand Growth

As covered in prior-year GCEOs, 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 electric vehicles (EVs), heat pumps, and data centers. Over the past two years, those scenarios have moved from projection to reality.

U.S. electricity consumption grew 2.6 percent in 2025 and is projected to continue rising. Growth is concentrated in the commercial (notably data centers, which have gained significant attention recently) and industrial sectors, alongside moderate contributions from EV adoption and residential electrification, including installations of heat pumps. Importantly, while total BTU consumption remains flat, electricity increasingly accounts for a larger share of that total, driving new 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 center demand is now front and center in discussions of electricity demand growth, with U.S. demand projections for 2026 being approximately 100 TWh higher than previous estimates.

Data center development has accelerated across Gulf Coast states. In Louisiana, Meta initially announced a $10 billion artificial intelligence data center campus in Richland Parish in December 2024, with construction expected to continue through 2030. Louisiana Economic Development described the project as one of the largest private capital investments in the state's history.[6] To serve the facility and accommodate broader growth, Entergy Louisiana initially proposed substantial generation and transmission additions, including three combined-cycle gas turbine (CCGT) facilities with 2,260 megawatts of combined capacity. In August 2025, the Louisiana Public Service Commission (PSC) approved Entergy Louisiana's planned investments and also authorized procurement of up to 1,500 megawatts of solar resources.[7] More recently, Southwestern Electric Power Co. (SWEPCO) announced in February 2026 that Amazon would construct new, large-scale data center campuses in Northwest Louisiana,[8] and Cleco Power, LLC, announced in May 2026 that it would serve a new 430-megawatt data center being constructed by Applied Digital near Boyce, Louisiana.[9] The scale of these data center projects and the infrastructure additions necessary to power them illustrates how a single large-load customer can materially affect utility resource planning and anticipated electricity demand.

Large data center projects have also been announced elsewhere in the region. In January 2024, Amazon Web Services announced plans to invest $10 billion in two data-center complexes in Madison County, Mississippi.[10] In January 2025, Compass Datacenters announced a separate campus in Lauderdale County consisting of eight data centers, planned for construction over eight years. Upon occupancy, the campus

[6] Louisiana Economic Development, "Meta Selects Northeast Louisiana as Site of $10 Billion Artificial Intelligence Optimized Data Center; Governor Jeff Landry Calls Investment 'A New Chapter' for State," December 4, 2024.

[7] Entergy Louisiana, "Entergy Louisiana to Power Meta's Data Center in Richland Parish," December 6, 2024. Entergy Louisiana, "Entergy Louisiana Receives LPSC Approval for Major Infrastructure Investments to Support Meta's Data Center and Improve Reliability," August 20, 2025.

[8] SWEPCO, "New Data Center Announced; SWEPCO Role Cited in Supporting Local Economic Growth," February 23, 2026.

[9] Cleco Power, "Cleco to Power Data Center Planned for Rapides Parish," May 26, 2026.

[10] Amazon, "AWS Plans to Invest $10 Billion in Mississippi, the Largest Capital Investment in the State's History," January 25, 2024.

was expected to represent $10 billion investment, including future tenants' information-technology equipment.[11] In Alabama, Meta initially announced an investment of more than $800 million in its Montgomery data center in May 2024, while other proposed developments include Project Marvel in Bessemer.[12]

Texas has also attracted large campuses at various stages of proposal, construction, and operation.[13] Examples include Crusoe's Stargate campus in Abilene,[14] the Fermi America–Texas Tech campus proposed near Amarillo,[15] Energy Abundance's proposed Data City near Laredo,[16] Stream's third San Antonio campus,[17] and Skybox's PowerCampus Austin in Hutto, Central Texas.[18]

The announced projects vary considerably in size, development schedule, and regulatory status. Some are under construction or supported by approved utility investments, while others remain in earlier stages of development. Consequently, announced investment and requested electrical load should not necessarily be interpreted as electricity demand that will materialize within the GCEO forecast horizon. Nevertheless, the number and scale of recent announcements indicate that data centers are becoming an increasingly important component of the Gulf Coast electricity outlook. The sections that follow examine the potential implications for electricity demand growth, generation requirements, and the regional fuel mix.

Although not all data center projects will necessarily move forward, several projects have expanded beyond their original announcements. For example, Meta announced a Richland Parish expansion representing more than $50 billion in regional investment in July 2026. Entergy Louisiana announced an additional infrastructure agreement in March 2026 involving seven new CCGT plants totaling more than 5,200 megawatts, alongside support for up to 2,500 megawatts of additional solar resources.[19] Amazon announced an additional $11 billion in Madison County investment in April 2026, and Meta increased its announced Montgomery investment to more than $1.5 billion in September 2025.[20]

Thus, data center development will be watched carefully, as this will be an important determinant of how quickly electricity demand grows.

> **GCEO continues to consider a scenario where total U.S. 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 traditional energy and petrochemical sectors. How data center investment occurs will be particularly important when considering future electric demand growth.**

1.3 Policy Uncertainty

Uncertainty regarding public policy continues to be a topic of discussion with stakeholders. As highlighted in last year's GCEO, energy investments are often capital intensive and require several years to plan, permit, finance, and construct. Changes in policy between administrations, as well as changes

[11] Office of Governor Tate Reeves, "Compass Datacenters Project Generates $10 Billion Investment in Lauderdale County," January 9, 2025.

[12] Meta Data Centers, "Hello, Montgomery!" May 2, 2024. City of Bessemer, "Updated Development Plans for Proposed Data Center Project," city website, accessed October 21, 2026.

[13] CBRE, "Fast-Growing North American Data Center Market Set Records in 2025," accessed October 21, 2026.

[14] Crusoe, "Crusoe Announces Flagship Abilene Data Center Is Live," September 30, 2025.

[15] Texas Tech University System, "TTU System and Fermi America Announce the World's Largest Advanced Energy and Intelligence Campus," June 26, 2025.

[16] Energy Abundance Development Corporation, "Data City, Texas," project page, accessed October 21, 2026.

[17] Stream Data Centers, "SATB," San Antonio campus project page, accessed October 21, 2026.

[18] Skybox Datacenters, "Austin Data Center Market," accessed October 21, 2026.

[19] Meta Data Centers, "Deepening Our Investment in Richland Parish, Louisiana," July 13, 2026. Entergy, "Entergy Louisiana Announces a New Agreement with Meta That Will Deliver an Additional $2B in Customer Savings," March 27, 2026.

[20] Office of Governor Tate Reeves, "Amazon Continues Mississippi Expansion, Announcing Plans to Invest a Total of $25 Billion Across the Magnolia State," April 9, 2026. Meta Data Centers, "Montgomery, We're Growing!" September 23, 2025.

occurring within a single administration, can therefore affect project economics and investment decisions even when the underlying resource or technology has not changed.

Federal offshore wind policy provides one recent example. After withdrawing the Outer Continental Shelf from new offshore wind leasing in January 2025,[21] the Trump administration reached agreements in 2026 under which several developers relinquished previously acquired leases in exchange for reimbursement or credit toward other U.S. energy investments. These actions illustrate how changes in federal priorities can affect projects that depend on federal leasing, permitting, tax incentives, or long-term regulatory treatment.[22]

International trade policy has also continued to change since last year's GCEO. In February 2026, the U.S. Supreme Court held in *Learning Resources, Inc. v. Trump* that the International Emergency Economic Powers Act (IEEPA) does not authorize the president to impose tariffs. The administration subsequently imposed a temporary 10 percent import surcharge under Section 122 of the Trade Act of 1974, which became subject to additional litigation. Meanwhile, tariffs imposed under other authorities, including Sections 232 and 301, remained subject to separate legal and administrative treatment. Tariff rates have therefore continued to vary by product, country of origin, statutory authority, and date of importation.

As discussed in prior GCEOs, tariffs can affect Gulf Coast energy investments through at least two channels. First, retaliatory tariffs or other trade restrictions can reduce access to international markets for energy and energy-intensive products produced in the region. Second, tariffs can increase the cost of imported machinery, electrical equipment, steel, and other inputs required for major capital projects. The Supreme Court decision reduced the president's ability to impose broad tariffs under IEEPA, but subsequent executive actions, litigation, and negotiations have continued to create uncertainty regarding the level and duration of U.S. trade restrictions.

The GCEO assumes that the federal policy framework in effect at the time of analysis continues through the forecast horizon. However, the experience of offshore wind leasing and the continuing changes in tariff policy illustrate that current policies may be modified through executive action, litigation, legislation, or a future change in administration. Such changes could affect the timing, cost, and financial viability of energy investments in the Gulf Coast region.

> **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, can adversely affect energy investments.**

1.4 Economic Outlook

The U.S. economy continued to expand during the first half of 2026, although the pace of growth moderated in the second quarter. Real gross domestic product (GDP) increased at seasonally adjusted annual rates of 2.1 percent in the first quarter and 1.5 percent in the second quarter. Employment also continued to expand, and the unemployment rate remained relatively low at 4.1 percent (seasonally adjusted) as of August 2026.

Inflation, however, increased during 2026 and again became a significant source of economic uncertainty. The Personal Consumption Expenditures (PCE) Price Index increased at an annual rate of 5.3 percent in the second quarter, while the index excluding food and energy increased 3.6 percent. Both measures therefore increased faster than real economic output during the quarter. By July, PCE inflation

[21] The White House, "Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects," January 20, 2025.

[22] U.S. Department of the Interior, "Interior Announces New Energy Agreement to Strengthen American Energy Security and Lower Costs," June 17, 2026.

was 3.7 percent over the preceding year, while core PCE inflation was 3.3 percent. The persistence of core inflation indicates that recent price pressures have not been limited to energy markets.

As discussed in the geopolitics section, the conflict with Iran has contributed to high oil and natural gas prices globally, and this has had a broader effect on prices. The Congressional Budget Office (CBO) estimates that higher energy prices associated with the conflict added 2.3 percentage points to the annualized rate of PCE inflation in the second quarter of 2026, when the overall rate reached 5.3 percent. Looking ahead to the first quarter of 2027, CBO estimates that the conflict will leave year-over-year PCE inflation 0.5 percentage points higher and core PCE inflation 0.3 percentage points higher than projected before the conflict. These estimates illustrate how geopolitical disruptions can affect the broader economy through energy prices, transportation costs, and ultimately the prices of other goods and services.[23]

Persistent inflation has also led to renewed monetary policy tightening. On September 16, 2026, the Federal Open Market Committee (FOMC) raised the target range for the federal funds rate by 25 basis points, from 3.50–3.75 percent to 3.75–4.00 percent, marking the first increase in the federal funds rate since 2023.[24] The Federal Reserve cited elevated inflation alongside continued solid economic activity, resilient domestic spending, robust capital investment, and a relatively stable labor market. Federal Reserve projections released with the decision also suggest that monetary policy could remain restrictive, with 16 of 18 FOMC participants projecting at least one additional increase in the federal funds rate during 2026.[25] Thus, higher inflation associated with energy markets and broader price pressures is increasingly being accompanied by higher borrowing costs, creating an additional source of uncertainty for investment and economic growth.

> **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. Due to high energy prices, global energy demand growth will continue but at a slower rate. 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.**

[23] Congressional Budget Office, *Estimating the Cost of Combat Operations Against Iran*, September 15, 2026, pp. 14–15.

[24] Board of Governors of the Federal Reserve System, "Federal Reserve Issues FOMC Statement," September 16, 2026.

[25] Board of Governors of the Federal Reserve System, *Summary of Economic Projections*, September 16, 2026.

2. Crude Oil and Natural Gas Production and Prices

2.1 Crude Oil and Natural Gas Production

U.S. oil production remains near record levels at approximately 13.97 MMbbl/d in August 2026, just below the all-time high of nearly 14.0 MMbbl/d set in October 2025. Natural gas production reached a new all-time high of approximately 137.0 billion cubic feet per day (Bcf/d) in July 2026, surpassing the previous peak of approximately 136.0 Bcf/d set in December 2025.

Gulf Coast oil and gas production trends are shown in Figure 1. The region has demonstrated robust production growth over nearly two decades, with crude oil production reaching 10.3 MMbbl/d and natural gas production at 69.5 Bcf/d as of August 2026. Crude oil production has shown consistent growth throughout this period, rising from under 3 MMbbl/d in the mid-2000s to near-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 2026. 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 approximately 551 active rigs as of February 2026.

This decline has mirrored the drop in oil prices with typical industry lags. The GCEO anticipates that oil and gas production will remain globally significant despite fewer active rigs, reflecting continued efficiency improvements in drilling and completion technologies. 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.

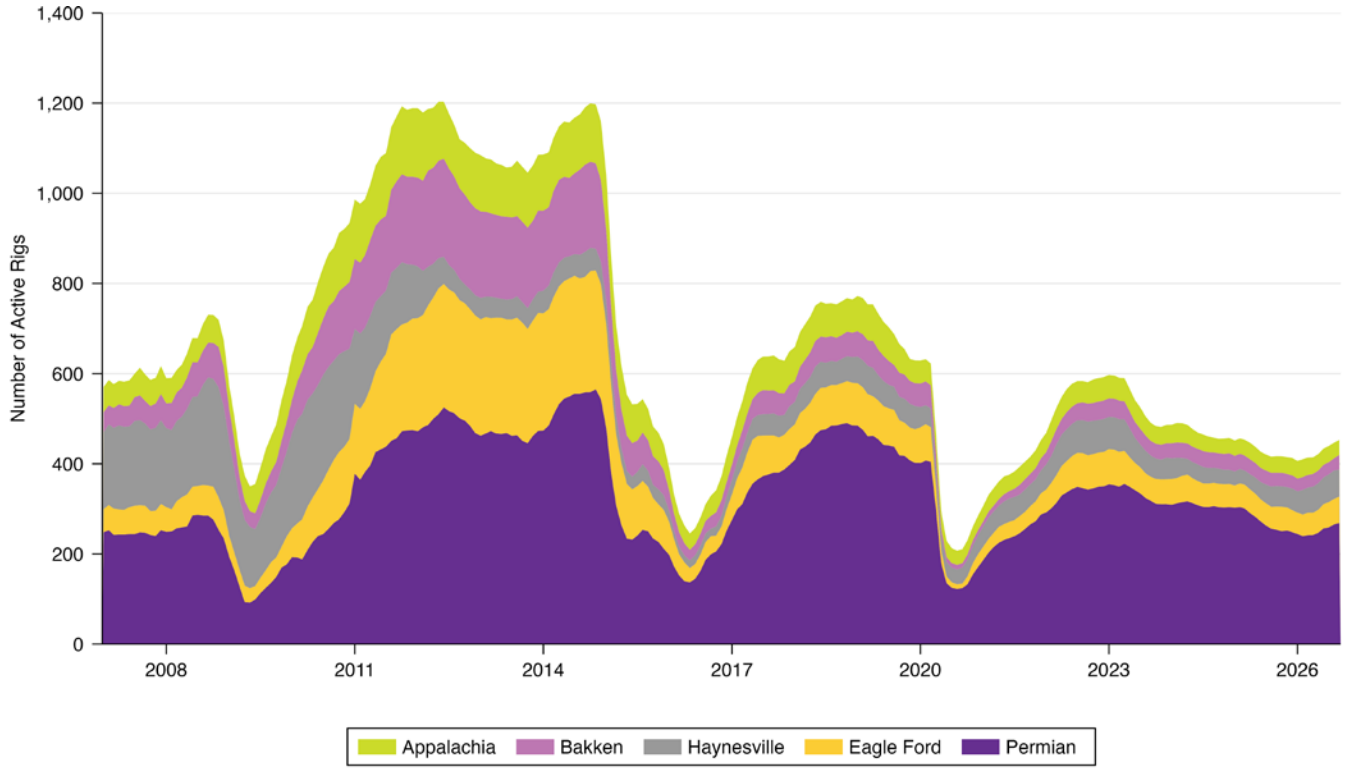
Figure 2: U.S. crude oil prices and rig count



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

Figure 3 displays rig activity levels in five U.S. production regions, as defined by Energy Information Administration's (EIA) *Short-Term Energy Outlook*. For the past several years, GCEO has noted that the Permian Basin has been the predominant U.S. shale play, and it 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, though drilling activity has recently rebounded, rising 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

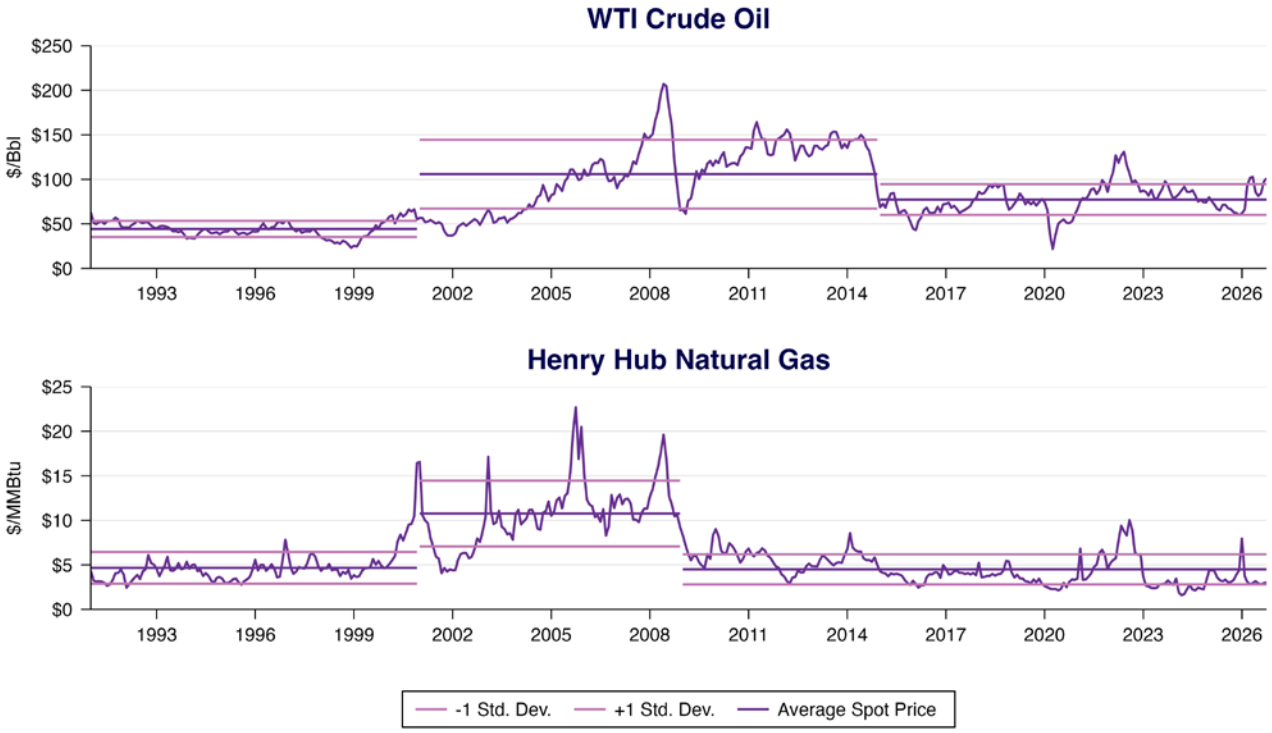
Figure 4 shows recent trends in both crude oil and natural gas commodity pricing. The top panel shows historical trends and pricing "epochs" for crude oil, whereas the bottom panel presents historical trends for natural gas pricing.

Historical 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 the present. These epochs differ in both their levels and variability.[26] The relevant question that was posed in last year's GCEO was whether natural gas prices had entered a new epoch that reflects a greater integration of U.S. natural gas markets with global markets. Prior to the advent of liquefied natural gas (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 2026, we have not observed a departure from this third "epoch" of natural gas prices, with current natural gas prices remaining relatively low.

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

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

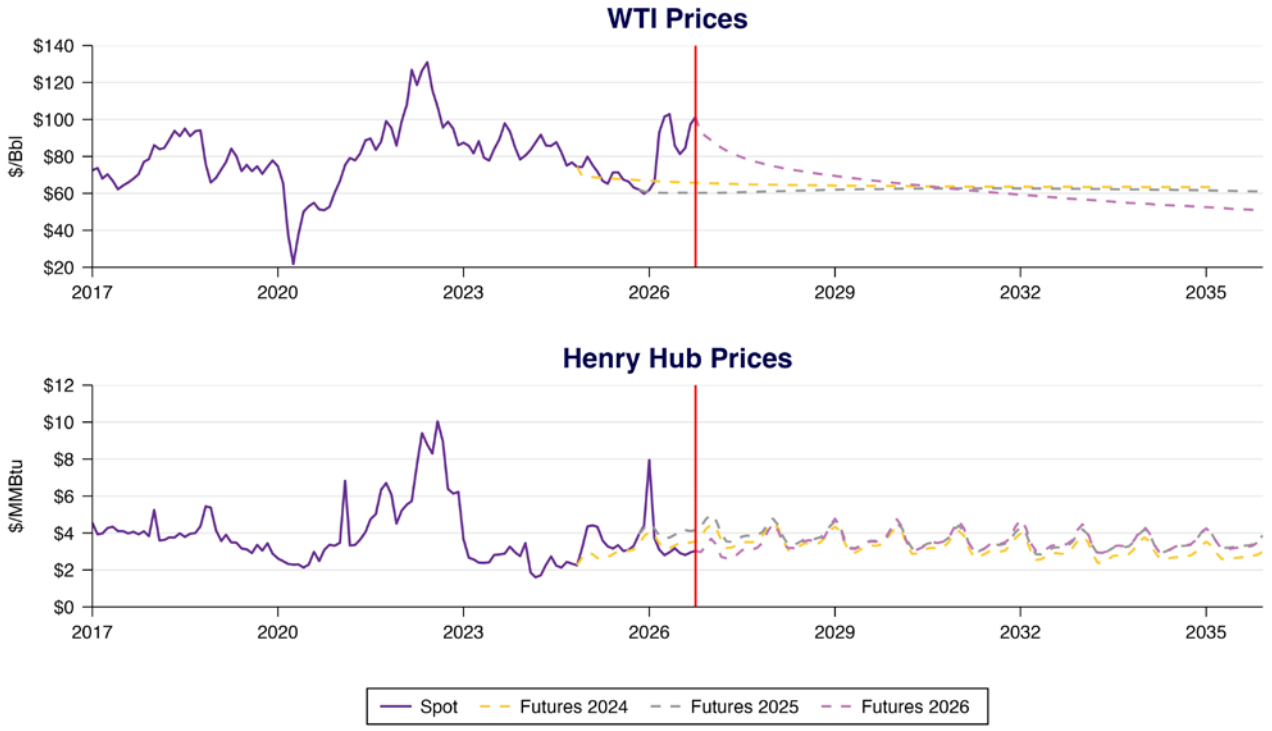


Source: U.S. Energy Information Administration. West Texas Intermediate Spot Price (top) and Henry Hub Natural Gas Spot Price (bottom). Inflation adjustment based on U.S. Consumer Price Index sourced from the Bureau of Labor Statistics.

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, quite simply, crashed crude oil prices in ways never experienced in the past. Crude oil prices bottomed out at a monthly average of less than $17 per barrel in April 2020 but quickly rebounded. But like natural gas, the global economic recovery alongside the war in Ukraine put significant upward pressure on oil prices in 2022. Although oil prices rose sharply in early 2026, they remained below the 2022 peak and, by mid-2026, had returned to within one standard deviation of the third-epoch average. As will be discussed next, they are anticipated to decline into the future.

Figure 5 compares historical prices and futures for both the WTI crude oil price (top panel) and Henry Hub natural gas price (bottom panel). 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



Sources: Futures data from Bloomberg. All other spot prices from the Energy Information Administration.
Note: Spot prices adjusted for inflation using the Consumer Price Index.

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 with a slight uptick from the last two years' futures prices. When prices shift outside of this range due to a shock (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, with prices anticipated at about $91 per barrel by the end of 2026.

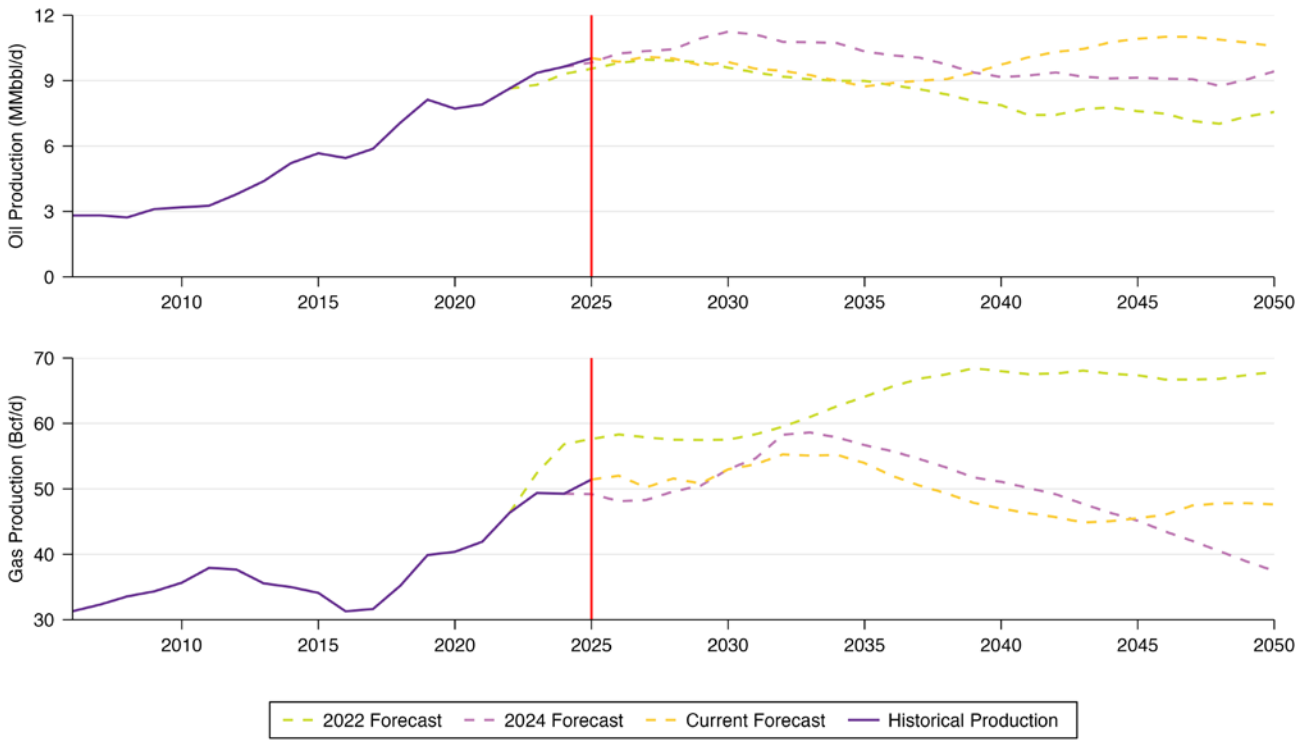
Natural gas prices are illustrated in the bottom panel of Figure 5. Interestingly, natural gas prices are *lower* than anticipated last year at this time, and as shown in Figure 4, natural gas prices are at the low end of the prices experienced over the past decade. U.S. natural gas prices have converged back to long-term norms relatively quickly 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 $3 and $5 per MMBtu. As will be discussed later, European and Asian markets have not experienced the same rapid convergence to pre-invasion norms, and this has continued 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.

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 EIA's Annual Energy Outlook (AEO) forecast model. Following tradition, both panels show the current forecast as well as those in the past two years' GCEOs. Note that the EIA did not publish an AEO 2024 (no new forecast in 2023). The AEO 2026 (the most recent) was released in April 2026.

Gulf Coast crude oil production is anticipated to remain relatively steady over the forecast horizon.[27] For perspective, in 2025, regional crude oil production averaged 10.0 MMbbl/d. In calendar year 2026, which at the time of this writing is partially completed, AEO estimates Gulf Coast oil production to average 9.9 MMbbl/d, a decrease of approximately 1 percent. By 2034, Gulf Coast oil production is forecasted at 9.0 MMbbl/d. This oil production forecast represents minor changes from last year's GCEO. Although not shown here, AEO also estimates U.S. oil production to decrease 6 percent by 2034.

Figure 6: Gulf Coast oil and natural gas production forecast



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

Figure 6 shows that Gulf Coast natural gas production is anticipated to continue to grow over the next decade.[28] In 2025, Gulf Coast natural gas production was about 51.4 Bcf/d, with AEO projecting 52.0 Bcf/d for 2026. By 2034, AEO estimates Gulf Coast natural gas production to reach around 55 Bcf/d, followed by a gradual decline through the mid-2040s. Although not shown graphically, nationwide natural gas production is expected to increase over the forecast horizon as well.

[27] 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.
[28] Ibid.

2.4 Drilling and Completion Technologies

The 2026 *Gulf Coast Energy Outlook* reported records achieved in 2025 in total measured depth and lateral lengths in the Haynesville shale. These records were not exceeded in 2026; however, drilling of long laterals has continued in the Haynesville shale and drilling efficiencies, as measured by days to total depth, have continued to improve. A record was achieved in 2026 with the drilling of the Highlander No. 2 well in Bayou Long Field in St. Martin Parish. The well reached a total depth of 30,862 feet in the Tuscaloosa Formation on February 17, 2026, making it the deepest well drilled in onshore Louisiana. Continued improvements in drilling efficiencies at these depths could have the potential to open up new natural gas resources in the Tuscaloosa Formation.

2.5 OCS Federal Lease Sales

The 2026 *Gulf Coast Energy Outlook* reported that the Big Beautiful Gulf Lease Sale (BBG 1) in 2025 was the first in the Gulf since 2023. Lease Sales BBG 2 and BBG 3 were held in 2026. BBG 2, held on March 11, 2026, received 38 total bids by 13 companies on 25 blocks covering approximately 141,000 acres. The total of high bids was $47 million. BBG 3 was held on August 12, 2026, and received 69 total bids by 16 companies on 59 blocks covering approximately 330,150 acres. The total of high bids was $82.7 million.

3. Midstream Constraints and Pipeline Activity

Geographic differences in crude oil and natural gas prices influence pipeline development. If prices at "Point A" are higher than at "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 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 2007–2015 time period. This close correlation between shipping and prices can explain between one-half and 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.[29] 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. Prior-year GCEOs anticipated 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 has continued to increase, pipeline infrastructure has kept up, with the share of barge and rail shipments continuing to be less than five percent.

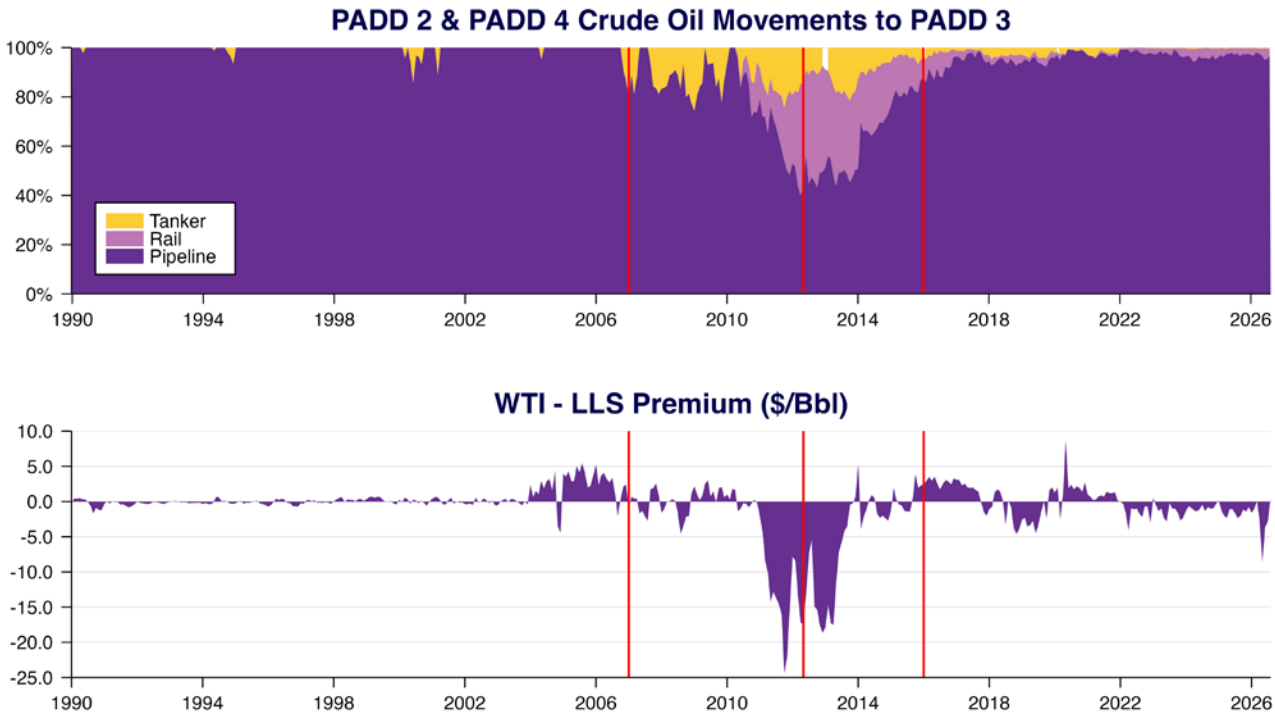
So far, 2026 has seen an increase in the spread between WTI and LLS. For perspective, in 2025, LLS traded for a premium of $1.43 per barrel. In March of 2026 (the first full month after the Iran conflict began), LLS and WTI were trading within about 2 cents per barrel. In April, this increased to $2.62 per barrel, and then in May to $8.73 per barrel. In June, the most recent full month of data available at the time of this writing, LLS was trading at a $3.63 premium to WTI.

This pattern is consistent with expectations. Higher oil prices have affected international oil markets the most. These international prices have also affected the Gulf Coast, with somewhat less of an impact on the Mid-Continent. Time will tell whether this LLS premium is short-lived, but to date the share of oil being shipped by rail and tanker has not yet responded to this differential, indicating that pipeline capacity is

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

not yet constrained. Since April, approximately 97 percent of crude shipped from the Mid-Continent to the Gulf Coast has continued to move via pipeline. If this price differential persists, it will send the signal to build additional pipeline capacity moving oil from the Mid-Continent to the Gulf Coast.

Figure 7: PADD 3 crude oil movements by transportation type

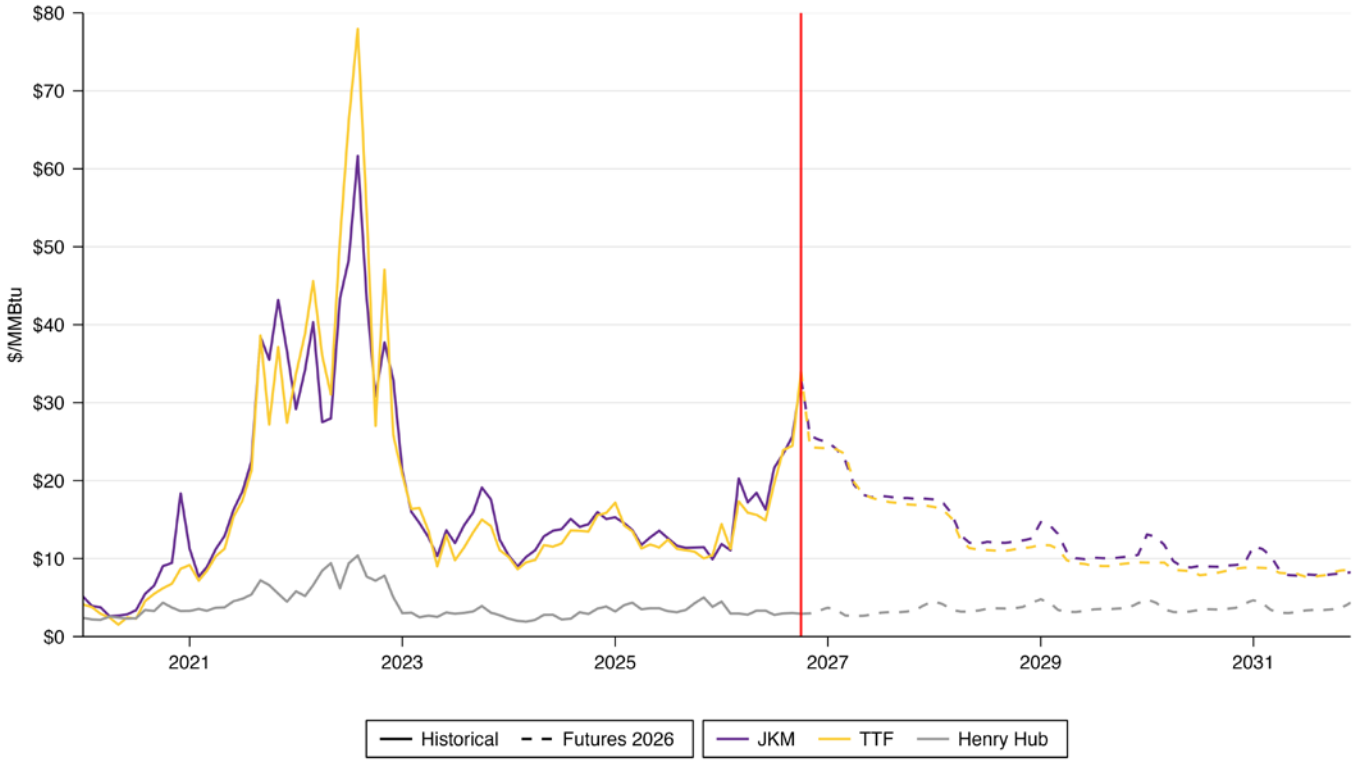


Source: U.S. Energy Information Administration, West Texas Intermediate Spot Price and Louisiana Light Sweet First Purchase Price. Movements between PADD Districts, by pipeline, tanker and barge, and rail.

The other notable spatial price difference is in international natural gas prices, and this too has been further exacerbated by the geopolitical conflict in the Middle East. Figure 8 shows historical series for Henry Hub (U.S. Gulf Coast), Title Transfer Facility (TTF—European benchmark), and the Japan Korea 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. In the most recent full month of data available, October of 2026, natural gas prices in Asia (represented by JKM) and Europe (represented by TTF) were approximately 1,000 percent more expensive than the Gulf Coast. Thus, the midstream 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 $7 per barrel more than West Texas Intermediate (in the U.S.) at the time of this report.

High international natural gas prices relative to the Gulf Coast are sending the signal for continued LNG export capacity expansion, which will be discussed further in Section 6.

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



Source: Bloomberg Terminal; U.S. Energy Information Administration.

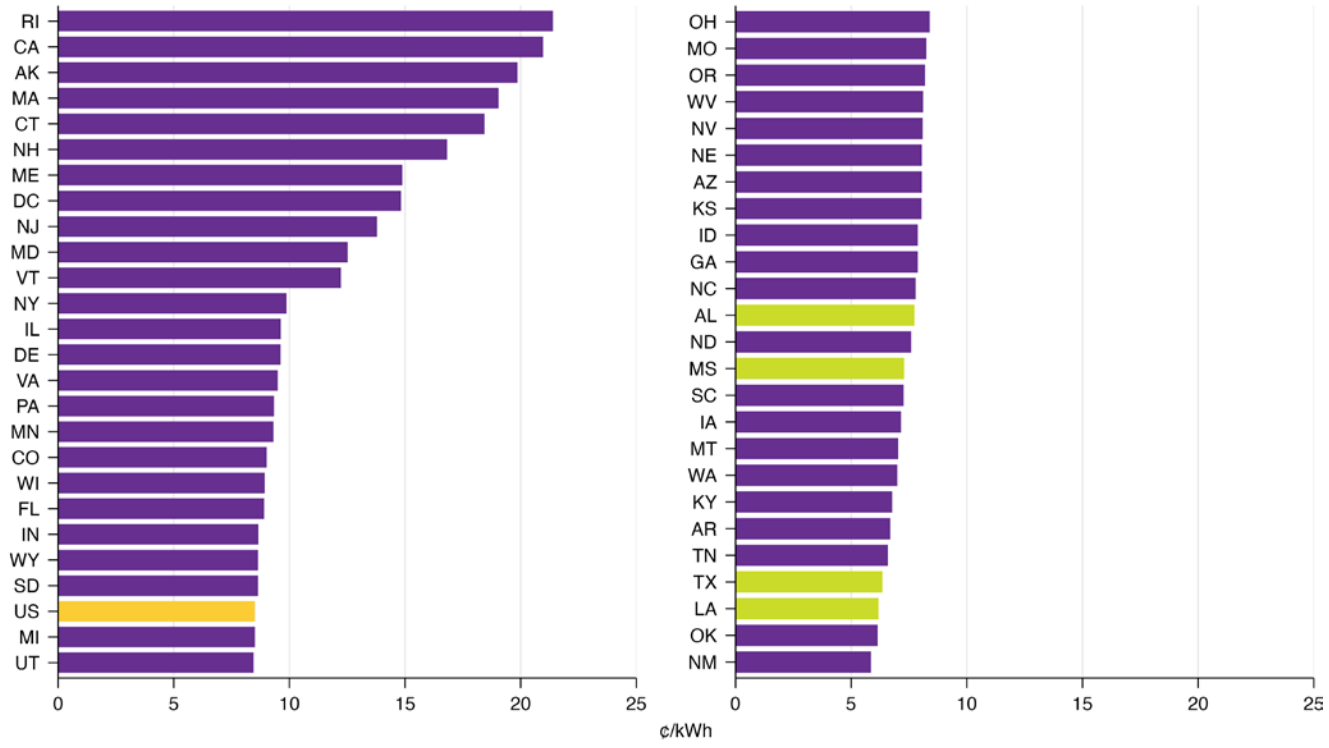
4. Power

4.1 Average Retail Prices

Electricity is a key input for manufacturing, and for certain energy-intensive operations, power can comprise over half 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 in Louisiana and Texas. Figure 9 shows recent (2025) average industrial retail electricity prices for the U.S. and each state.

The U.S. average industrial electricity rate in 2025 was 8.5¢ per kilowatt-hour (kWh), which is considerably higher than the Gulf Coast weighted regional average of 6.5¢/kWh, giving the region a 23 percent cost advantage. All Gulf Coast states are below the national average industrial retail price, with Louisiana having the lowest industrial retail electricity price in the region at 6.2¢/kWh and the third-lowest in the U.S. The average industrial retail rate in Texas in 2025 was 6.4¢/kWh, about 3 percent higher than Louisiana.

Figure 9: Average retail industrial electricity prices



Source: U.S. Energy Information Administration 861 annual data.
Retail sales of electricity to ultimate consumers. Hawaii (31.5¢/kWh) is excluded from the figure.

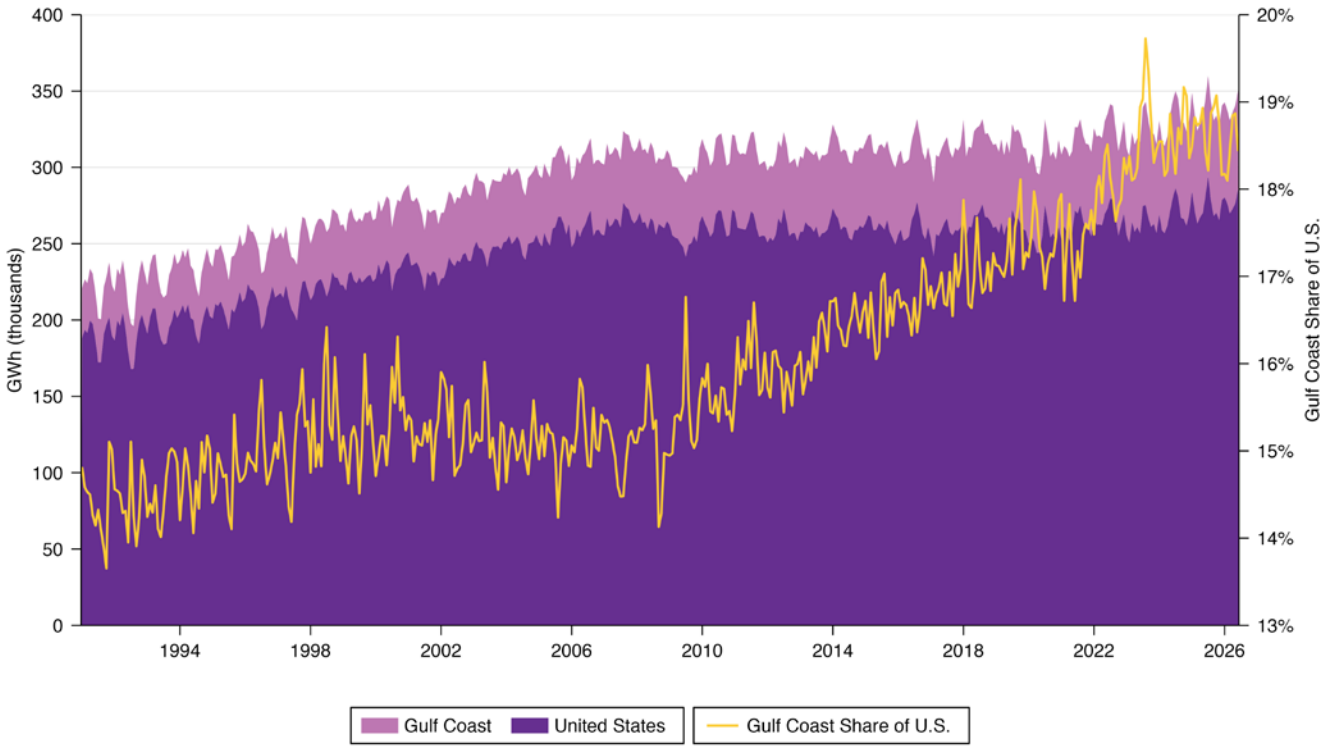
The Gulf Coast has been competitively priced relative to the national average for the last decade. Average industrial prices increased in the Gulf Coast region in 2025 relative to 2024 due to higher natural gas and wholesale power market prices. During the 10-year period from 2016 to 2025, the Gulf Coast average industrial electricity price increased 20.2 percent versus the U.S. average industrial electricity price increase of 25.9 percent. Note that both the Gulf Coast and U.S. average industrial price changes are

below the change in the overall Producer Price Index (PPI) during the same 10-year period. Additionally, the Gulf Coast saw significant growth in industrial electricity sales during the past 10 years at 40.6 percent versus U.S. average growth of 7.5 percent. From 2016 to 2025, industrial electricity sales growth varied significantly across Gulf Coast states: Alabama and Mississippi were essentially unchanged at 0.3 and -0.7 percent, respectively; Louisiana grew 16 percent, and Texas led with 66 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 modest over the last 10 years, increasing by 8.4 percent. In fact, U.S. industrial electricity sales have yet to reach their late 1990s peak, whereas the Gulf Coast region has seen significant growth at 40.6 percent, led by Louisiana and Texas. 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 2016 and, at the time of writing, accounts for almost 27 percent of nationwide industrial sales. This growth in industrial sales has been spurred by energy manufacturing activity in Louisiana and Texas, which will be discussed further in Section 5. While the U.S. has seen industrial electricity sales increase 7.5 percent since 2016, individual states have experienced varying changes, with most states experiencing a decline.

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



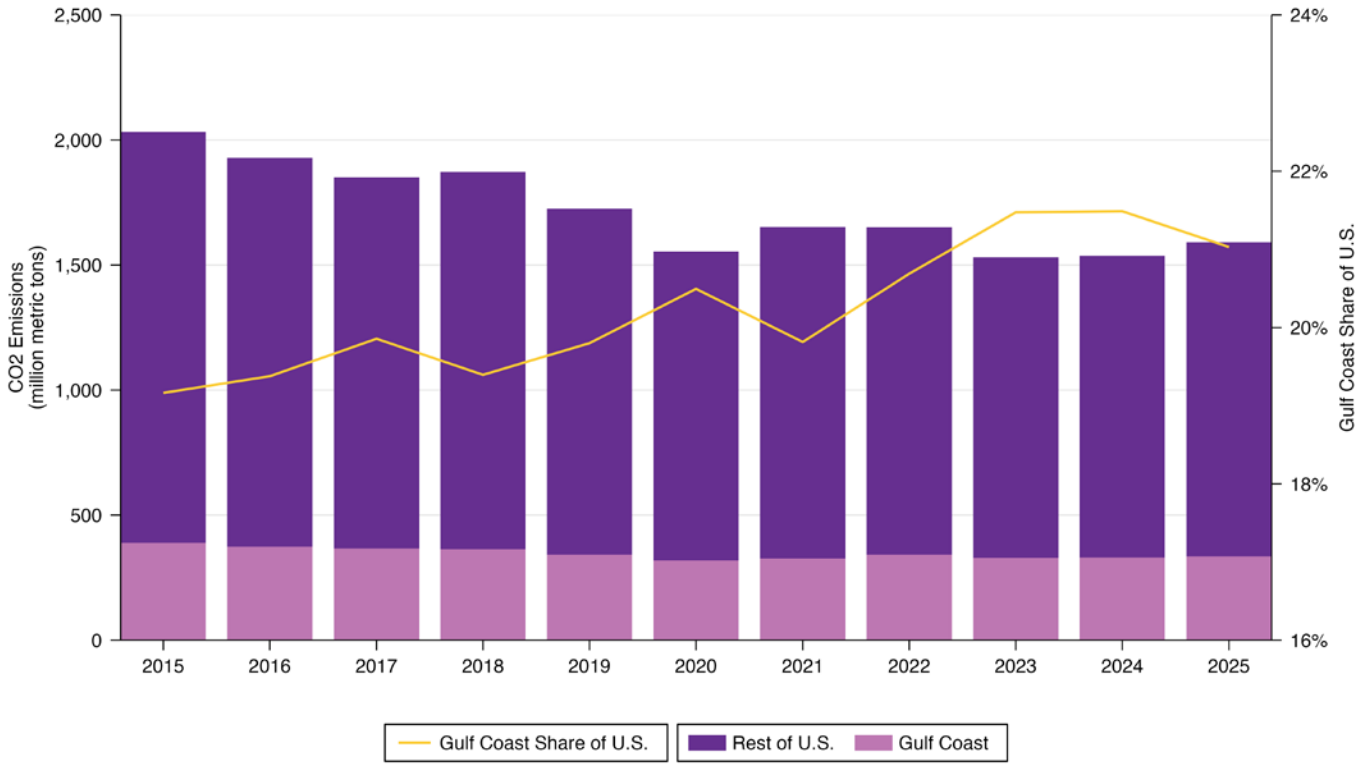
Source: U.S. Energy Information Administration (EIA) Form 861M monthly data.
Retail sales of electricity to ultimate consumers.

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 2025. Between 2015 and

2025, U.S. and Gulf Coast power-generation-related CO_2 emissions decreased by 22 percent and 14 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 efficient 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 level in decades. Emissions edged up again in 2025, rising 3.6 percent nationwide and 1.4 percent in the Gulf Coast.

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



Sources: Energy Information Administration, Form EIA-923 Power Plant Operations Report and Form EIA-860 Annual Electric Generator Report.
Note: The emissions data presented include total emissions from both electricity generation and the production of useful thermal output.

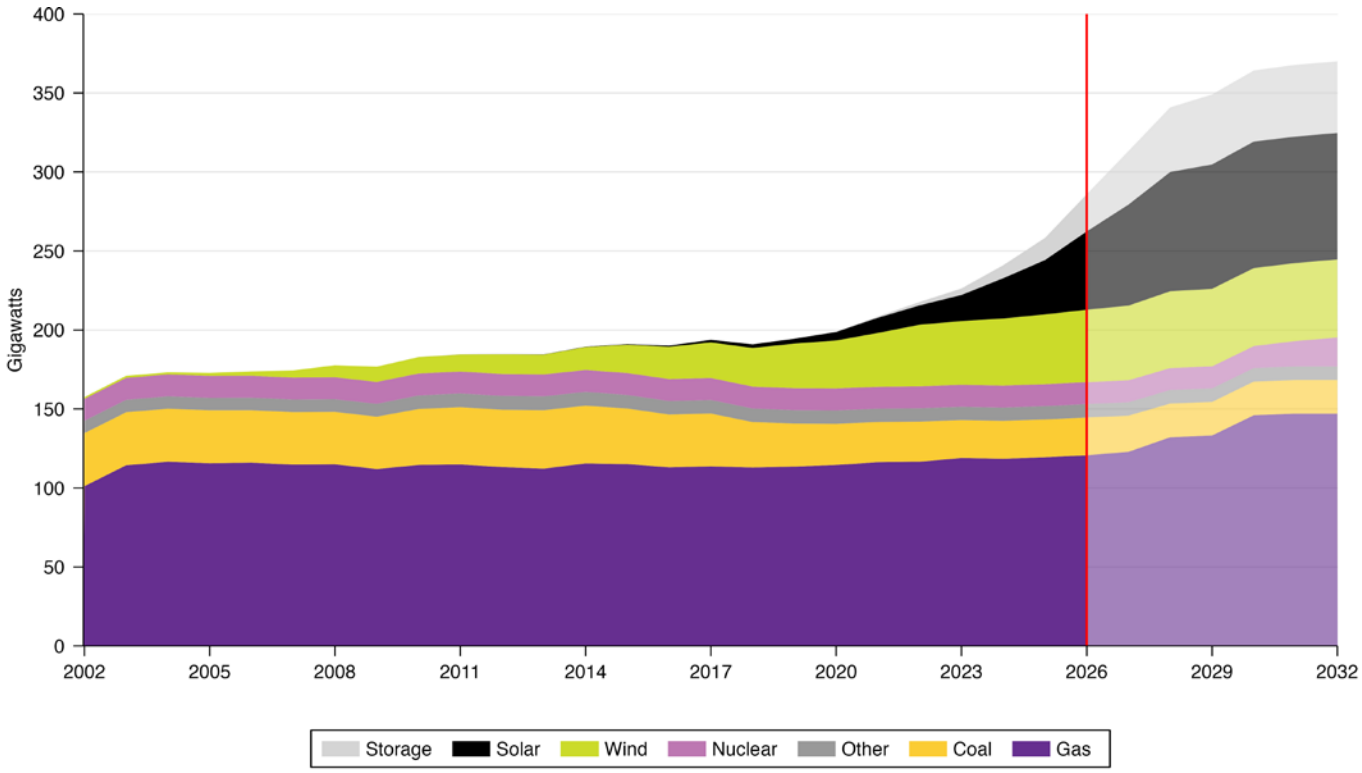
4.4 Generation Capacity Investment

Figure 12 shows historical and planned power generation capacity by fuel source for the Gulf Coast region. According to the U.S. Energy Information Administration's Preliminary Monthly Electric Generator Inventory (Form EIA-860M), approximately 41,400 MW of solar PV generating capacity is currently planned or under construction in the Gulf Coast region, of which roughly 16,300 MW is already under construction. In the Midcontinent Independent System Operator, Inc. (MISO) wholesale market alone, Louisiana currently has approximately 13,000 MW of natural gas, solar PV, wind, energy storage, or hybrid renewable plus energy storage capacity in the interconnection queue being studied, with an additional approximately 6,980 MW of natural gas and renewable resources having completed the interconnection process, with approximately 1,640 MW of those projects currently under construction. The amount of generation capacity in the MISO queue in Louisiana is significantly less than the level of capacity reported in recent years,

a decrease largely attributable to MISO reforms designed to address queue management. To reduce the pervasive withdrawals and speculative projects that were crowding the queue, MISO—in coordination with Federal Energy Regulatory Commission (FERC)—increased milestone payments, introduced automatic withdrawal payments, and capped the volume of new queue entries. As a result, project volume has dropped sharply since 2024, but remaining proposals may be more viable and more likely to be constructed and successfully interconnect to the transmission grid. 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 almost 3,500 MW of wind capacity in the planning phase, much of that within the Electric Reliability Council of Texas (ERCOT) wholesale market, although there are several wind projects being studied by MISO in Louisiana representing a total capacity of 536 MW. Additionally, approximately 26,300 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 2025, natural gas accounted for 40.8 percent of utility-scale electricity generated nationwide, nuclear for 17.7 percent, coal for 16.6 percent, wind for 10.5 percent, and solar for 6.7 percent.[30] Total carbon-free generation in the U.S. accounted for approximately 42 percent of total utility-scale electricity generated in 2025. Given the pace of new construction and planned unit retirements, renewable energy's share of electricity generation is likely to increase, but natural gas is expected to continue to be the largest fuel source for electricity generation for the foreseeable future.

Figure 12: Gulf Coast power generation capacity and outlook



Source: U.S. Energy Information Administration, Preliminary Monthly Electric Generator Inventory.

[30] U.S. Energy Information Administration, Electric Power Monthly, Tables 1.1 and 1.1.A, "Net Generation by Energy Source: Total (All Sectors)" and "Net Generation from Renewable Sources: Total (All Sectors)," 2025 data.

4.5 Future Electricity Growth and Resource Adequacy

From 2000 to 2020, U.S. electricity sales (MWh) growth slowed from about 2 percent annually prior to that period 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, offsetting population growth and new construction. In contrast, total U.S. electricity sales in 2025 grew by approximately 10 percent versus the pandemic-impacted year 2020, led by commercial (17 percent increase) and industrial (9 percent increase) sales.

While overall electricity sales have grown only modestly 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 179 percent increase in total electricity sales comparing 2025 to 2005. On the other end of the spectrum, 22 states have seen total electricity sales decline, led by Connecticut, which has seen electricity sales fall by 16 percent since 2005. Louisiana has seen overall electricity sales grow 26 percent over the last 20 years, which is more than twice the U.S. average. Among the 14 fully restructured states, where most consumers can choose their supplier, total electricity sales have fallen since 2005 in every state except Texas, by an average of 6 percent, led by an average decline in industrial sales of 22 percent. Again, there is significant variation among those states, with Maryland seeing the largest decline in its industrial electricity sales, which are down 84 percent since 2005. Average electric rates in those states, especially among consumers who have a choice of alternative suppliers, are also higher than the U.S. average.

Since the 2020 pandemic, total U.S. electricity sales have grown by 10 percent and are projected to grow at an elevated rate for at least the next five years. Contrast the growth since 2020 with an increase of only 1 percent between 2005 and 2020, primarily due to a decrease in industrial sales, no growth in commercial sales, and a modest increase of 8 percent in residential sales. The combination of onshoring of some U.S. manufacturing (the Gulf Coast "industrial renaissance"), investments in clean energy technology facilities (EVs, batteries for EVs, solar panels, etc.) triggered by Infrastructure Investment and Jobs Act (IIJA) and Inflation Reduction Act (IRA) tax and other incentives that have since been rescinded, rapid growth of hyperscale cloud and Artificial Intelligence (AI) data centers, and electrification of transportation and buildings are increasing forecasted electricity sales growth. At the same time, significant policy shifts in 2025 with respect to tax incentives available for clean energy manufacturing and EVs have led to cancellation of some manufacturing projects and greater uncertainty regarding consumer demand for EVs in the U.S., at least in the near future.

With respect to the region, Entergy Corporation is forecasting that its five regulated utilities will see total electricity sales grow by 65 TWh annually in 2030 versus 2025, led by industrial MWh sales growing 16 percent annually.[31] Entergy Corporation is also forecasting $67 billion of capital spending between 2026 and 2030, with the majority tied to generation investments to serve load growth. 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 69 GW of company-wide incremental load growth, led by strong data center demand, along with approximately $78 billion of capital investment planned for 2026 through 2030.[32] In its most recent investor presentation, Cleco Power has also highlighted electricity sales growth opportunities tied to Louisiana's pro-business climate as well as its electrification and decarbonization efforts.[33]

Stronger electricity sales growth, mainly driven by industrial expansions and new hyperscale data centers, coupled with recent and pending retirements of older fossil fuel generating plants in the Gulf Coast states

[31] Presentation made at Entergy's 2026 Investor Day held June 9, 2026.

[32] American Electric Power, Presentation for Investor Meetings, September 2026.

[33] CLECO Power LLC, Presentation made at EEI Financial Conference held November 9-11, 2025.

and the U.S. more broadly, may present challenges to ensuring ongoing 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, such as Louisiana and Texas, utilities and independent generators are likely to 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. continue to experience challenges with near-term resource adequacy, with adverse impacts on wholesale markets and consumer prices. For example, the PJM regional transmission organization (RTO) oversees a wholesale market that encompasses all or parts of 13 states and the District of Columbia, most of which are fully deregulated where consumers have choice of electricity supplier. In PJM's most recent capacity auctions, prices have spiked, contributing to significant rate increases being passed on to consumers. Much of the 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. For example, 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 minimum capacity obligation (MCO)[34] and also expanded its integrated resource planning (IRP) rules to apply to the state's electric cooperatives.[35] On October 1, 2026, the Louisiana PSC Staff issued a report summarizing the second year of annual resource adequacy filings made by utilities in May.[36] For the May 2026 Resource Adequacy demonstration, utilities subject to the Louisiana PSC's oversight were required to show coverage of at least 90 percent of their forecasted capacity obligation for the 2026/2027 MISO Planning Year that began June 1, 50 percent for the 2027/2028 and 2028/2029 Planning Years, and 30 percent for the 2029/2030 Planning Year. All of the 11 electric utilities that submitted a report demonstrated compliance with the 90 percent threshold, although Staff noted instances in which a utility provided data indicating it fell below one or more pre-set percentage thresholds in a future MISO planning cycle.

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. In 2025, MISO implemented a new Expedited Resource Addition Study (ERAS) process 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 78 projects representing approximately 43,300 MW have been submitted into ERAS, with some of those having been withdrawn. Louisiana is well represented with approximately 20 percent of the active amount of generation capacity that MISO is evaluating.

4.6 Large Electric Loads

With the recent growth of hyperscale (100 MW+) AI data centers, including in Louisiana (e.g., Meta, Amazon, Applied Digital, and Hut 8), state and federal policymakers have taken various actions to facilitate grid interconnections and ensure other consumers are protected. During the 2025 Regular Session, Senate Resolution (SR) 195 created the *Task Force on Energy Infrastructure and Modernization*, which was extended for two years in 2026 per SR 174. From that effort, Senate Bill 490 (SB 490) was proposed during the 2026 Regular Session, which would have allowed for a Private Use Electrical Network (PUEN)

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

[35] 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.*

[36] 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, 2026.*

that meets certain qualifications.[37] While SB 490 did not pass, the Louisiana PSC subsequently initiated a new PUEN rulemaking, which is ongoing.[38]

Separately, the Louisiana PSC adopted its Lightning Amendment to its Market Based Mechanisms (MBM) General Order in December 2025 to address utilities seeking approval to construct new generation and related infrastructure to serve a new large load. In March 2026, the Louisiana PSC Staff issued a document entitled "*Large Load Additions Non-Binding Guidelines*."[39] The non-binding guidelines are intended to be a companion to other relevant Louisiana PSC General Orders and cover 12 sections including the large load's characteristics, resource adequacy, transmission, stranded cost risk mitigation, rate design and cost recovery, grid reliability and power quality, fuel supply, ramp management, market implications, environmental and local area impacts, and ongoing monitoring. In June 2026, Gov. Landry issued Executive Order No. 26-058 entitled the "*Louisiana Ratepayer and Community Protection Initiative Criteria for LED Certifications for Data Center and Large-Load Investments*."[40] The Executive Order directs Louisiana Economic Development (LED) to establish a *Ratepayer* and *Community Protection* Framework as a condition of participating in Louisiana's Data Center Sales and Use Tax Exemption program.

In June 2026, FERC issued Show Cause Orders to six RTOs/ISOs including MISO and SPP requiring them to either justify their current transmission tariffs as just and reasonable or propose reforms to address integration of "large loads," which FERC defined as a peak load greater than 50 MW, interconnected at a voltage above 69 kV, and not part of a co-location arrangement.[41] FERC directed RTOs/ISOs to focus their efforts on five areas: efficient interconnection study processes, cost allocation and related service agreements, co-location rules for behind-the-meter generation, flexible load services to address operational flexibility, and proximate generation studies for large loads and generators that are in close proximity (i.e., within two substations). Thus far, MISO has submitted several proposals to FERC, including for a new Zero Injection Generator Interconnection Agreement,[42] and proposed revisions to its FERC-approved tariff implementing Interconnection Reliability Requirements for Large Loads,[43] and a new Large Load Addition Resource Study (LARS) process.[44] MISO is also evaluating a new offering called Flexible Large-load Interconnection and Transmission Service (FLITS), which could offer a faster path to interconnection in return for non-firm service. SPP sought an extension to submit tariff changes, which FERC granted. Prior to the FERC Show Cause Order, SPP had implemented several reforms related to interconnection and service to large loads, including its enhanced study procedures for High Impact Large Loads (HILLs),[45] its High Impact Large Load Generation Assessment (HILLGA) process,[46] and its Conditional High Impact Large Load Service (CHILLS),[47] which allows a HILL (or a portion of a HILL) to utilize non-firm service when transmission service is unavailable due to lack of generation or completion of network upgrades necessary to provide firm service.

[37] Senate Bill 490 by Senator Bob Hensgens.

[38] Louisiana PSC Docket No. R-37905; In re: *Notice of Proceeding Regarding Determination and Evaluation of Private Use Electrical Networks in Order to Enable Generation to Serve New Large Loads Looking to Locate in Louisiana.*

[39] Louisiana Public Service Commission, Large Load Additions Non-Binding Guidelines, March 2026.

[40] Louisiana Economic Development, "Louisiana Sets New National Standard for Responsible Industrial Growth," news release, June 25, 2026.

[41] See FERC Docket No. EL26-70-000; Large Load Show Cause Order.

[42] See FERC Docket No. ER26-3552-000; Zero Injection Generator Interconnection Agreement (ZGIA).

[43] See FERC Docket No. ER26-3650-000; Interconnection Reliability Requirements for Large Loads.

[44] See FERC Docket No. ER27-25-000; Large Load Addition Resource Study.

[45] See FERC Docket No. ER26-247-000; Submission of Tariff Revisions to Add the High Impact Large Load Processes and High Impact Large Load Generation Assessment.

[46] Ibid.

[47] See FERC Docket No. ER26-1323-000; Submission of Tariff Revisions to Add Conditional High Impact Large Load Service.

5. Regional Energy Manufacturing Investment

Gulf Coast energy manufacturing investment continues to demonstrate considerable strength, supported by the region's abundant natural gas resources, extensive energy infrastructure, emerging technologies, and proximity to major export markets. This economic run has lasted close to 15 years and shows few signs of slowing. The 2027 GCEO anticipates approximately $374 billion in regional energy manufacturing investment between 2026 and 2033, reflecting another substantial wave of announced capital investments. The nature of this investment, however, continues to evolve as firms leverage the region's existing world-scale industrial capacity through additional investments designed to improve operating efficiencies, reduce emissions, and capture new market opportunities. LNG export development continues to lead this expansion, with approximately $190 billion in announced investments across the region.

While LNG remains the principal driver of energy manufacturing investments, the rapid expansion of data centers is creating an additional source of demand for electric and natural gas infrastructure. Last year, the GCEO began tracking these investments as an addition to its energy manufacturing outlook, given their considerable impact on supporting energy production and transportation infrastructure. The scale and rapid expansion of these energy-intensive facilities have made them an increasingly important component of the regional energy economy. Their growth is expected to create additional requirements for electric generation, transmission, and natural gas transportation infrastructure, further reinforcing the region's role as a major center for energy-related development.

Over the past few years, the region has increasingly seen considerable incremental capital investments in technologies such as low-emissions/clean hydrogen and ammonia production, carbon capture and storage (CCS), biofuels, and other forms of clean energy infrastructure. Over the past four years, the GCEO has incorporated analyses examining how investments were changing the energy landscape along the Gulf Coast. This trend continues in the 2027 GCEO.

The 2027 GCEO continues to recognize that transition investments depend heavily on continued state and federal policy support, particularly the substantial tax incentives established by the IRA of 2022. Public policy continues to strongly influence these transition investments and, as will be discussed below, is leading to considerable headwinds for many recently announced projects.

5.1 Regional Trends

The 2027 GCEO shows that the Gulf Coast region continues to attract an outsized level of energy manufacturing investment relative to other regions in the U.S. The region's competitive advantages, including abundant natural gas supplies, deepwater ports, extensive pipeline infrastructure, skilled labor, and proximity to major export markets, continue to support significant industrial development. These advantages have positioned the Gulf Coast region as a destination for LNG export facilities, petrochemical manufacturing, and emerging energy technologies. The continued expansion of these industries suggests that the region's favorable investment fundamentals remain strong, despite changing economic and policy conditions.

However, even along the Gulf Coast, projects are starting to exhibit longer development timelines driven by financing, supply chain, trade, and policy uncertainty.[48,49,50] While developers continue to indicate long-run confidence about the region's fundamentals (deepwater 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 previously announced and newly announced projects.

The current Gulf Coast investment portfolio continues to be influenced by broader macroeconomic conditions, including elevated interest rates, slower growth in key export markets, and tighter global engineering, procurement, and construction (EPC) support and skilled labor availability. Regulatory and policy uncertainty continue to influence project development, particularly for emerging energy transition technologies. Policy shifts and uncertainties have also had the effect of making other, more traditional investments, such as LNG export terminals, more attractive.

Recent energy manufacturing and infrastructure project announcements have been influenced by a changing public policy environment that has increasingly emphasized traditional energy development and energy-intensive infrastructure. These developments include: (1) the resumption of federal LNG export authorization reviews;[51] (2) federal initiatives to accelerate the permitting of data centers and associated energy infrastructure;[52] and (3) state tax incentives supporting large-scale data center investments.[53] Meanwhile, transition-related investments face continued policy and regulatory uncertainty, particularly following changes to the clean hydrogen production tax credit (45V), which shortened the deadline for qualifying projects,[54] and Louisiana's October 2025 moratorium on the review of new Class VI carbon sequestration permit applications.[55] Conversely, Texas received Class VI primacy in December 2025, potentially streamlining the permitting process for CCS projects.[56] Texas also continues to provide substantial incentives for industrial development through its Jobs, Energy, Technology and Innovation (JETI) program and tax exemptions for qualifying data center investments.[57,58] Collectively, these policy developments are creating a more favorable investment environment for traditional energy manufacturing and energy-intensive infrastructure, while introducing additional uncertainty for certain transition investments. These differences may ultimately influence which announced projects secure financing, reach final investment decisions (FIDs), and achieve their anticipated commercial operation dates (CODs).

Commercial structures are also evolving, influencing project announcements and development. LNG offtake agreements and clean ammonia contracts are increasingly incorporating indexed pricing contract terms, commodity destination and delivery flexibility, and diversified investor participation. These arrangements are designed to manage commercial risks while supporting the financing of large-scale capital investments. Meanwhile, growing demand for lower-emission energy commodities continues to create opportunities for additional investments in emissions reduction technologies and associated infrastructure.

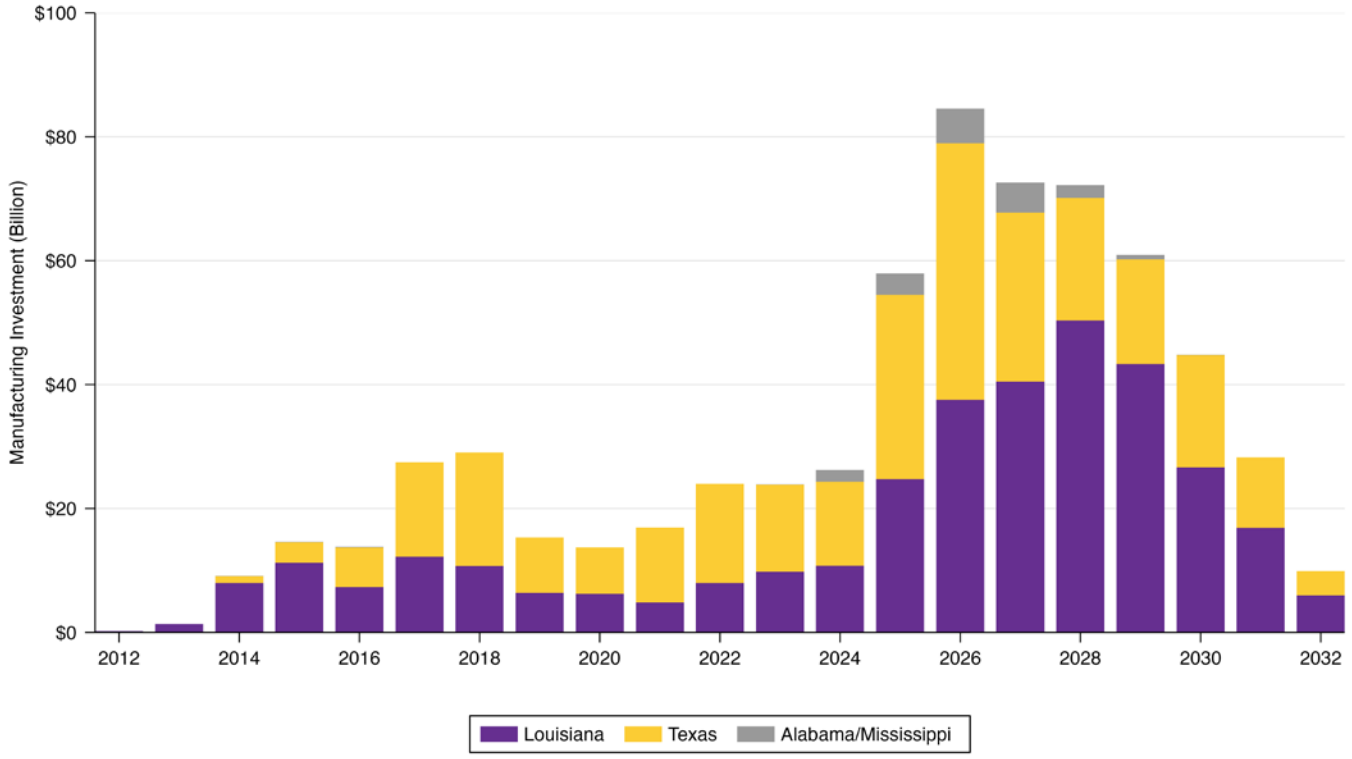
Petrochemical developers continue to focus on investments designed to alleviate production bottlenecks, increase energy efficiency, and address emissions control requirements while preserving competitiveness in a global market under volatile margins. Uncertainty about policy and incentive eligibility can

[48] U.S. Department of Energy, "Fact Sheet: Temporary Pause on Pending Applications for Authorization to Export Liquefied Natural Gas to Non-FTA Countries," 2024.
[49] Reuters, "Rising U.S. Labor Costs Threaten to Derail New LNG Projects," June 24, 2024.
[50] S&P Global Commodity Insights, "U.S. Gulf Leads Global Blue Ammonia Price Falls in Jan Amid Project Uncertainty," February 18, 2025.
[51] U.S. Department of Energy, "U.S. Department of Energy Reverses Biden LNG Pause, Restores Trump Energy Dominance Agenda," January 20, 2025.
[52] Executive Order 14318, "Accelerating Federal Permitting of Data Center Infrastructure," Federal Register 90, no. 142 (July 28, 2025): 35385–88.
[53] Louisiana State Legislature, "Exemptions; Data Center Facility Equipment," Louisiana Revised Statutes § 47:305.73, accessed October 19, 2026.
[54] U.S. Congress, Public Law 119-21, § 70511, "Termination of Clean Hydrogen Production Credit," July 4, 2025.
[55] Office of the Governor of Louisiana, "CO_2 Capture and Storage Limits and Moratorium," Executive Order JML 25-119, October 15, 2025.
[56] Railroad Commission of Texas, "Texas Granted Primacy Over Class VI Wells," November 12, 2025.
[57] Office of the Governor of Texas, "Texas Jobs, Energy, Technology and Innovation (JETI)," accessed October 19, 2026.
[58] Texas Comptroller of Public Accounts, "State Sales Tax Exemption for Qualifying Data Centers and Qualifying Large Data Center Projects," accessed October 19, 2026.

delay final investment decisions (FID) by making expected project returns more difficult to assess, and greater policy clarity could even encourage investment more effectively than financial incentives that are viewed as uncertain.

From 2012 to 2026, cumulative Gulf Coast energy-manufacturing investment reached close to $358 billion, led by Texas (~$188 billion) and Louisiana (~$159 billion). Louisiana's historical investment trends have been driven primarily by recent LNG build-outs, while Texas leads in diversified non-LNG chemical and refining capacity (see "Non-LNG" categories).

Figure 13: Regional energy manufacturing investment



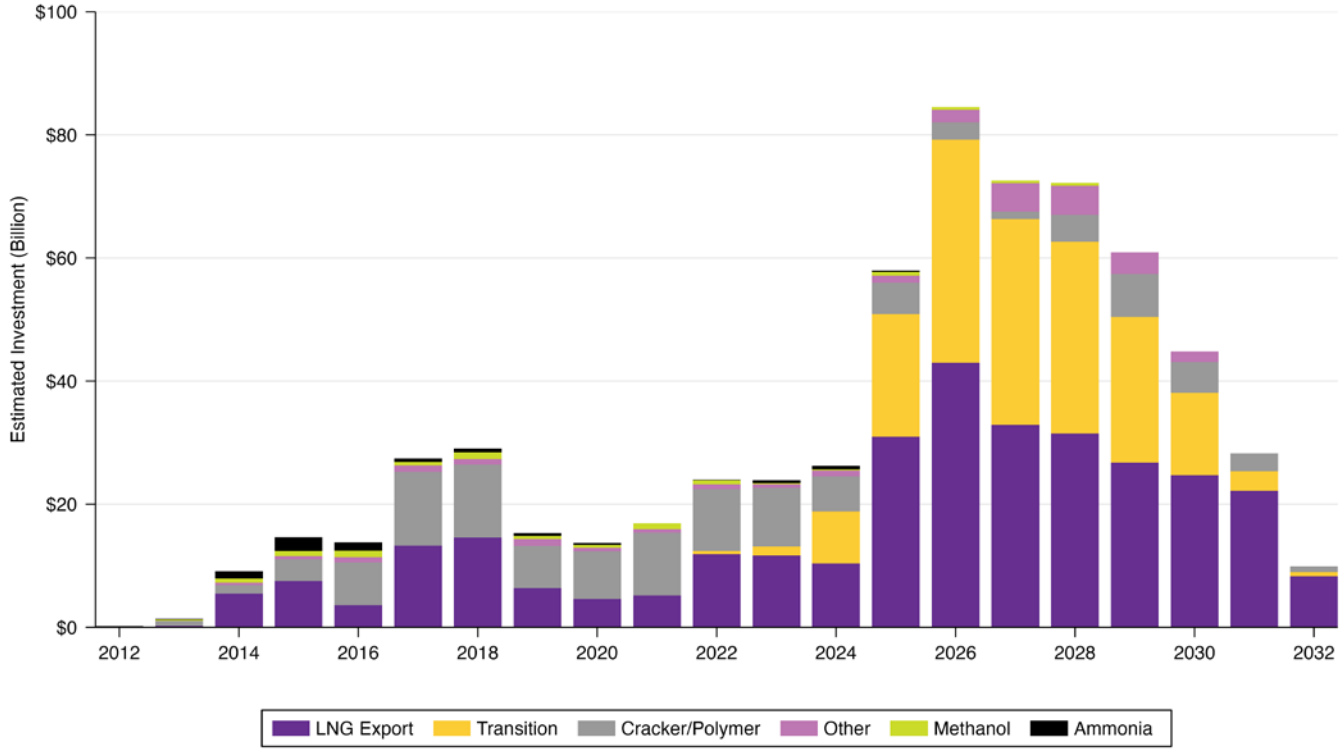
Source: Author's construct.
Note: Includes the Hyundai Steel mill. Only traditional energy manufacturing investments are included (no data center investments).

As shown in Figure 13, annual regional energy manufacturing investments have been cyclical, seeing an initial peak around 2018 of approximately $29 billion, near the height of the shale-gas revolution, before declining amid international trade frictions, growing global industrial competition, and ultimately the global pandemic. A regional recovery arose in 2022, getting to around $24 billion, with increases each year since that time. Estimated investment increased substantially in 2025, reaching approximately $58 billion, and is estimated at $85 billion in 2026, reflecting another substantial wave of regional energy manufacturing development.

Historically, regional energy manufacturing investment has been concentrated heavily (in dollar terms) in LNG export facilities and conventional non-LNG manufacturing, accounting for approximately $169 billion and $123 billion, respectively, between 2012 and 2026 (Figure 14). However, transition-related investments have increased considerably in recent years, rising from approximately $1.5 billion in 2023 to $20

billion in 2025 and nearly $36 billion in 2026. Despite the substantial growth in transition investments, LNG remained the largest individual investment category in 2026, accounting for approximately $43 billion, compared with $36 billion in transition investments and $5 billion in other manufacturing activities.

Figure 14: Regional energy manufacturing investment by sector



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.

5.2 Investment Outlook and Uncertainty

The 2027 GCEO tracks around $289 billion in additional announced energy manufacturing investment between 2027 and 2033 (Table 1), following an estimated $85 billion in 2026. While the number is substantial, uncertainty and risk abound. 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 may continue to sequence modules and delay FIDs while preserving options. At this point in time, the consensus outlook among many analysts (including the 2027 GCEO) is that continued uncertainty will result in deferred, not cancelled, projects.

Table 1: Gulf Coast projected energy manufacturing investments

Year	Texas				Louisiana			
	LNG	Non-LNG	Transition	Total	LNG	Non-LNG	Transition	Total
	(million $)							
2026	18,711	2,992	19,711	41,414	21,281	1,365	14,861	37,507
2027	10,810	2,815	13,618	27,243	19,677	2,336	18,486	40,498
2028	2,154	4,509	13,171	19,835	28,558	3,824	17,936	50,318
2029	4,288	4,500	8,082	16,870	22,415	5,304	15,606	43,325
2030	11,316	1,573	5,297	18,186	13,387	5,170	8,051	26,608
2031	11,140	120	133	11,393	11,072	2,784	3,015	16,872
2032	3,908	-	9	3,917	4,374	908	682	5,964
2033	293	-	-	293	383	66	44	493
Total	**$ 62,619**	**$ 16,510**	**$ 60,021**	**$ 139,151**	**$ 121,147**	**$ 21,758**	**$ 78,681**	**$ 221,586**

Year	Other GOM				Total GOM			
	LNG	Non-LNG	Transition	Total	LNG	Non-LNG	Transition	Total
	(million $)							
2026	2,984	991	1,670	5,645	42,976	5,348	36,242	84,566
2027	2,370	1,162	1,330	4,862	32,857	6,312	33,434	72,603
2028	773	1,190	64	2,026	31,485	9,524	31,171	72,180
2029	56	661	3	719	26,759	10,465	23,690	60,914
2030	-	6	-	6	24,702	6,750	13,348	44,800
2031	-	-	-	-	22,211	2,905	3,148	28,264
2032	-	-	-	-	8,282	908	692	9,882
2033	-	-	-	-	676	66	44	786
Total	**$ 6,182**	**$ 4,009**	**$ 3,067**	**$ 13,259**	**$ 189,949**	**$ 42,278**	**$ 141,769**	**$ 373,995**

Source: Author's construct.

On a sectoral basis, LNG continues to lead regional energy manufacturing investment, with approximately $147 billion in anticipated capital expenditures between 2027 and 2033. Louisiana accounts for the majority of these investments ($100 billion), followed by Texas ($44 billion). Continued LNG development is supported by the region's abundant natural gas supplies, existing pipeline infrastructure, and access to international export markets. The growing portfolio of LNG export facilities and capacity expansions reflects continued demand for U.S. natural gas, particularly in European and Asian markets.

Several major LNG developments have recently secured financing and advanced into construction. In Louisiana, Woodside reached a FID on its $17.5 billion Louisiana LNG facility in April 2025, while Venture Global secured financing for both phases of its CP2 LNG project, representing more than $20 billion in

combined project financing.[59,60] Recently announced LNG projects are sustained, at this point in time, by European and Asian demand for natural gas supply diversification, 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.[61,62]

Refining investments (see "Non-LNG" category) continue to focus on reliability, energy efficiency, and fuels compliance rather than new greenfield capacity. Petrochemicals continue to benefit from advantaged ethane and proximity to export terminals; however, margin cyclicality and continued economic weakness in Asia temper outlooks. Developers are emphasizing phased debottlenecking and brownfield expansions with shorter paybacks given these risks. The 2027 GCEO identifies approximately $37 billion in additional announced non-LNG manufacturing investment between 2027 and 2033, with Louisiana ($20 billion) accounting for a larger share than Texas ($14 billion), followed by Mississippi and Alabama ($3 billion).

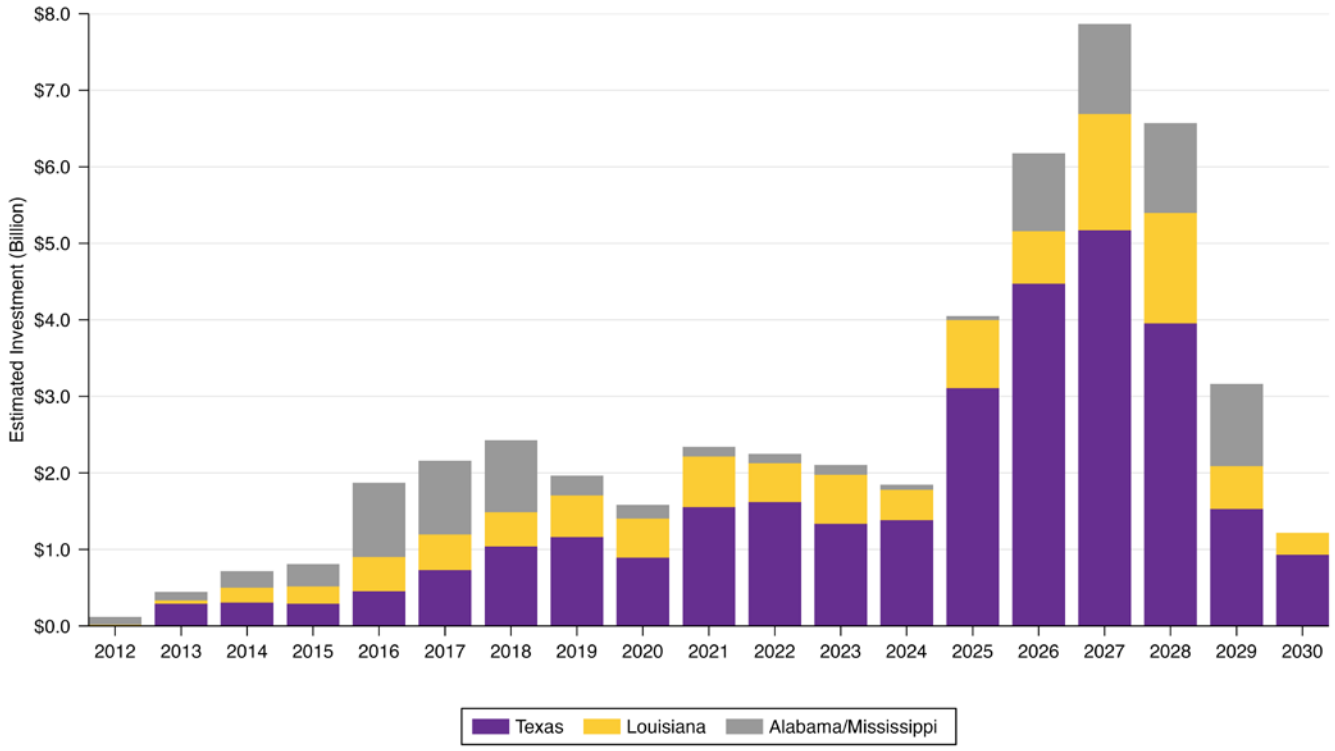
A new addition to the 2027 GCEO is the inclusion of regional natural gas pipeline investments. Expanding LNG exports, industrial manufacturing, and energy-intensive data centers are increasing demand for transportation infrastructure that moves gas from producing regions to growing demand centers. The U.S. EIA reports that approximately 45 billion cubic feet per day (Bcf/d) of new pipeline capacity is planned nationwide for 2026 and 2027, with most additions concentrated in Texas and Louisiana.[63]

The 2027 GCEO anticipates approximately $25 billion in regional natural gas pipeline investment between 2026 and 2030, led by Texas ($16 billion), Louisiana ($4.5 billion), and Mississippi and Alabama ($4.4 billion). As shown in Figure 15, annual investment is anticipated to peak at approximately $7.9 billion in 2027, reflecting substantial additions to regional transportation infrastructure. Much of this development is associated with increasing natural gas production in the Permian and Haynesville basins and expanding deliveries to LNG export terminals along the Gulf Coast.[64]

Meanwhile, the rapid expansion of data centers and other large industrial loads is creating additional demand for electric generation, including natural gas-fired facilities. The EIA anticipates record natural gas consumption for electric generation in 2027, driven in part by growing commercial and industrial electricity demand.[65] Collectively, these developments suggest that natural gas pipeline investment will remain an important component of the region's broader energy infrastructure expansion, supporting both traditional energy manufacturing and emerging sources of energy demand.

[59] Woodside Energy, "Woodside Approves Louisiana LNG Development," April 28, 2025.
[60] Venture Global, "Venture Global Announces Final Investment Decision and Financial Close for Phase 2 of CP2 LNG," March 13, 2026.
[61] U.S. Department of Energy, 2024 LNG Export Study: Energy, Economic, and Environmental Assessment of U.S. LNG Exports, 2025.
[62] McKinsey & Company, "Crunch Time in the North American LNG Industry: How to Meet Demand," December 7, 2023.
[63] U.S. Energy Information Administration, "Most Planned Natural Gas Pipeline Capacity Additions in 2026 and 2027 Originate in Texas," *Today in Energy*, May 26, 2026.
[64] U.S. Energy Information Administration, "Most Natural Gas Pipelines Built in 2025 Connect the South Central United States to Supply," *Today in Energy*, February 25, 2026.
[65] U.S. Energy Information Administration, "Natural Gas for Power Generation Flat This Summer, Record High Expected in 2027," *Today in Energy*, May 28, 2026.

Figure 15: Regional natural gas pipeline investment by state



Source: EIA Data, Project Announcements, Author's construct.

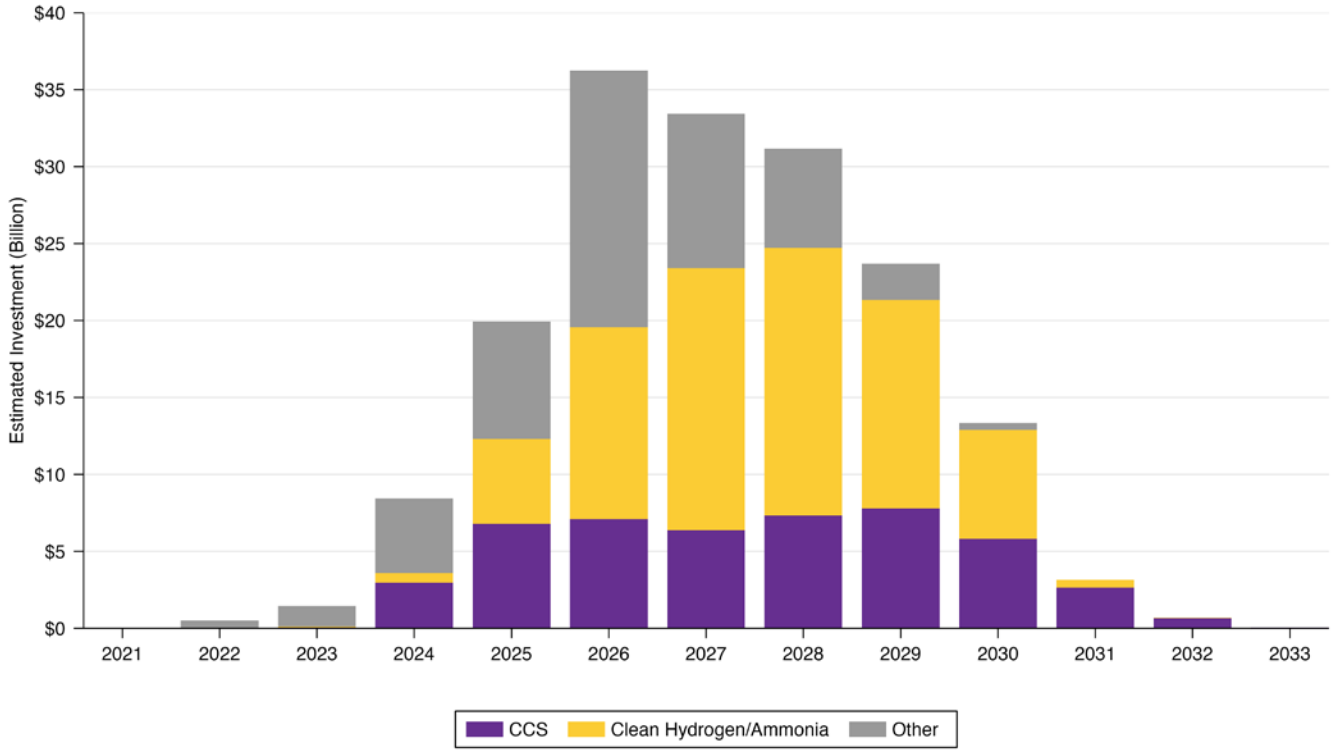
Transition investments continue to represent a substantial component of the Gulf Coast investment outlook, although they remain concentrated in Louisiana and sensitive to evolving federal policies and regulatory uncertainty. The 2027 GCEO identifies approximately $106 billion in additional announced regional transition investments between 2027 and 2033, with the majority ($64 billion) in Louisiana, followed by Texas ($40 billion).

5.3 Regional Transition Investment Decomposition

Transition investments remain an important component of 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 2027 GCEO identifies approximately $106 billion in additional announced regional transition investments between 2027 and 2033, including $56 billion in clean hydrogen and ammonia, $31 billion in CCS, and $19 billion in other transition manufacturing. Although the magnitude of these investments remains substantial, the development outlook has become increasingly uncertain as changing federal policies, permitting requirements, and commercial conditions affect the economic viability of proposed projects.

Figure 16: Regional transition investment decomposition



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

Clean Hydrogen & Ammonia: These investments offer one of the clearest and potentially most profitable opportunities for the region's established energy manufacturing sector, particularly commodity chemicals. Clean hydrogen and ammonia projects can build on existing chemical production capacity, pipeline corridors, natural gas infrastructure, affordable electricity, and deepwater transportation access. Their primary constraint has been the additional financial support needed to become economically viable; until recently, the IRA appeared capable of providing that support.

Recent federal policy changes have introduced additional uncertainty for these developments. The 2025 federal tax legislation shortened the eligibility window for the clean hydrogen production tax credit (45V), requiring qualifying facilities to begin construction before January 1, 2028.[66] The International Energy Agency (IEA) reports that global low-emission hydrogen development has slowed, with announced production capacity targeting 2030 declining to approximately 27 million metric tons annually as projects are delayed or cancelled.[67] These developments highlight the continued challenges associated with securing sufficient commercial demand and financing for large-scale hydrogen investments. Increasingly, transition project developers are having to deal with the realities of uncertain 45V eligibility (electric-grid matching, additionality),[68] electrolyzer supply chain constraints,[69] and ammonia export logistics.[70] While

[66] Internal Revenue Service, "Instructions for Form 7210 (2025): Clean Hydrogen Production Credit."
[67] International Energy Agency, Global Hydrogen Review 2026 (Paris: International Energy Agency, June 18, 2026).
[68] International Renewable Energy Agency (IRENA) and World Trade Organization (WTO), Enabling Global Trade in Renewable Hydrogen and Derivative Commodities, 2024.
[69] International Energy Agency (IEA), Global Hydrogen Review 2024, 2024.
[70] Koerber, M., "Clean Hydrogen Across the Atlantic? Policy Alignment and Transatlantic Cooperation in the Emerging Hydrogen Economy," American Council on Germany, 2025.

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.

CCS: Carbon capture and storage remains a significant component of the Gulf Coast transition investment outlook, supported by the region's favorable geological formations, extensive industrial infrastructure, and opportunities to integrate carbon capture into existing manufacturing operations. The federal carbon sequestration tax credit (45Q) also continues to provide financial support for qualifying investments, with the 2025 federal tax legislation establishing greater parity between credits for dedicated geologic storage and qualified carbon utilization, including enhanced oil recovery.[71]

However, the regional regulatory environment has become increasingly divided. In November 2025, the U.S. Environmental Protection Agency (EPA) approved Texas's application for Class VI primacy, transferring responsibility for permitting geologic CO_2 storage wells to the state, effective December 2025.[72] Conversely, Louisiana issued an executive order in October 2025 establishing a moratorium on the review of new Class VI permit applications, while requiring additional review and prioritization of previously submitted applications.[73] Although these developments do not eliminate opportunities for CCS investment, differences in state permitting requirements and project approval timelines may influence where developers pursue new investments and the timing of associated industrial developments.

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.

5.4 Energy-Intensive Demand Drivers: Gulf Coast Data Center Growth

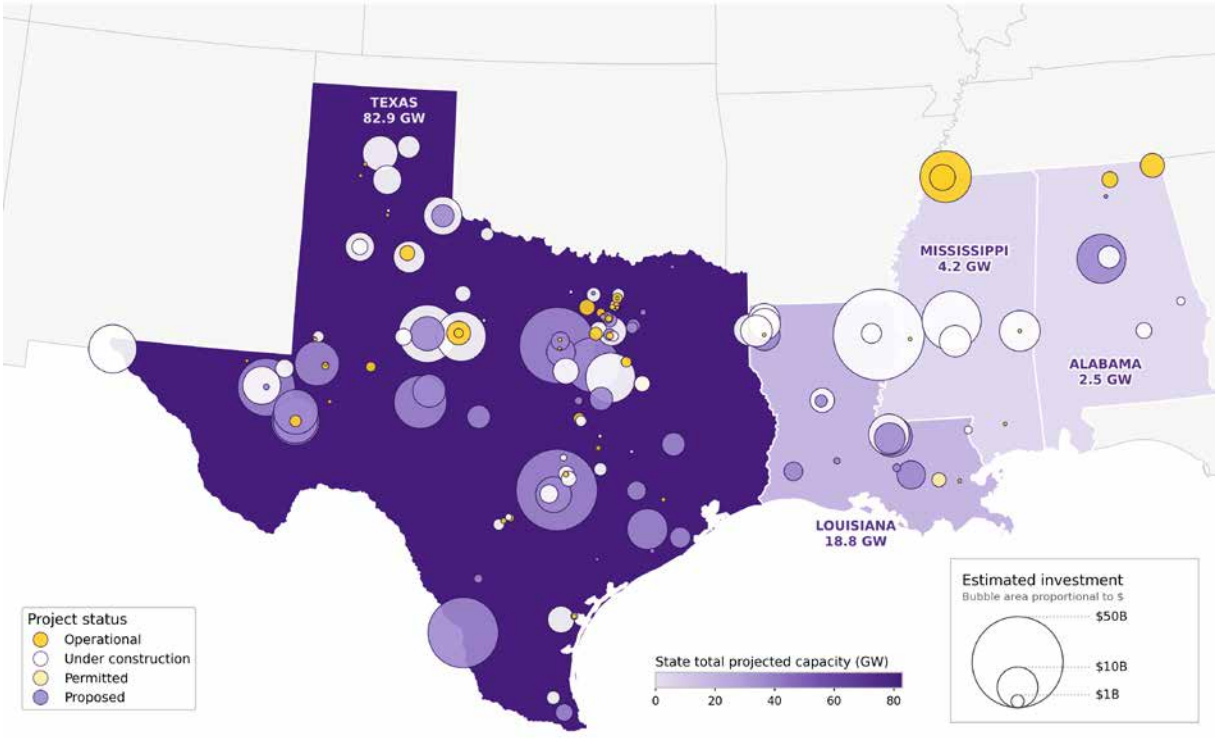
While not traditional "energy manufacturing," data centers have emerged as one of the most significant drivers of regional energy demand, with implications for electric generation, transmission, and natural gas infrastructure. The 2027 GCEO identifies as much as $623 billion in announced regional data center–related investment between 2026 and 2033, including investments in associated power generation. As shown in Figure 17, the majority of this investment is concentrated in Texas ($426 billion, or 68 percent), followed by Louisiana ($122 billion), Mississippi ($57 billion), and Alabama ($19 billion). These investments are tracked separately from the baseline energy manufacturing outlook and represent an additional source of regional capital investment.

[71] Internal Revenue Service, "Instructions for Form 8933 (12/2025): Carbon Oxide Sequestration Credit."

[72] U.S. Environmental Protection Agency, "EPA Grants the State of Texas Primacy to Protect Underground Water Resources," November 12, 2025.

[73] State of Louisiana, Office of the Governor, "CO_2 Capture and Storage Limits and Moratorium," Executive Order JML 25-119, October 15, 2025.

Figure 17: Regional data center investment map

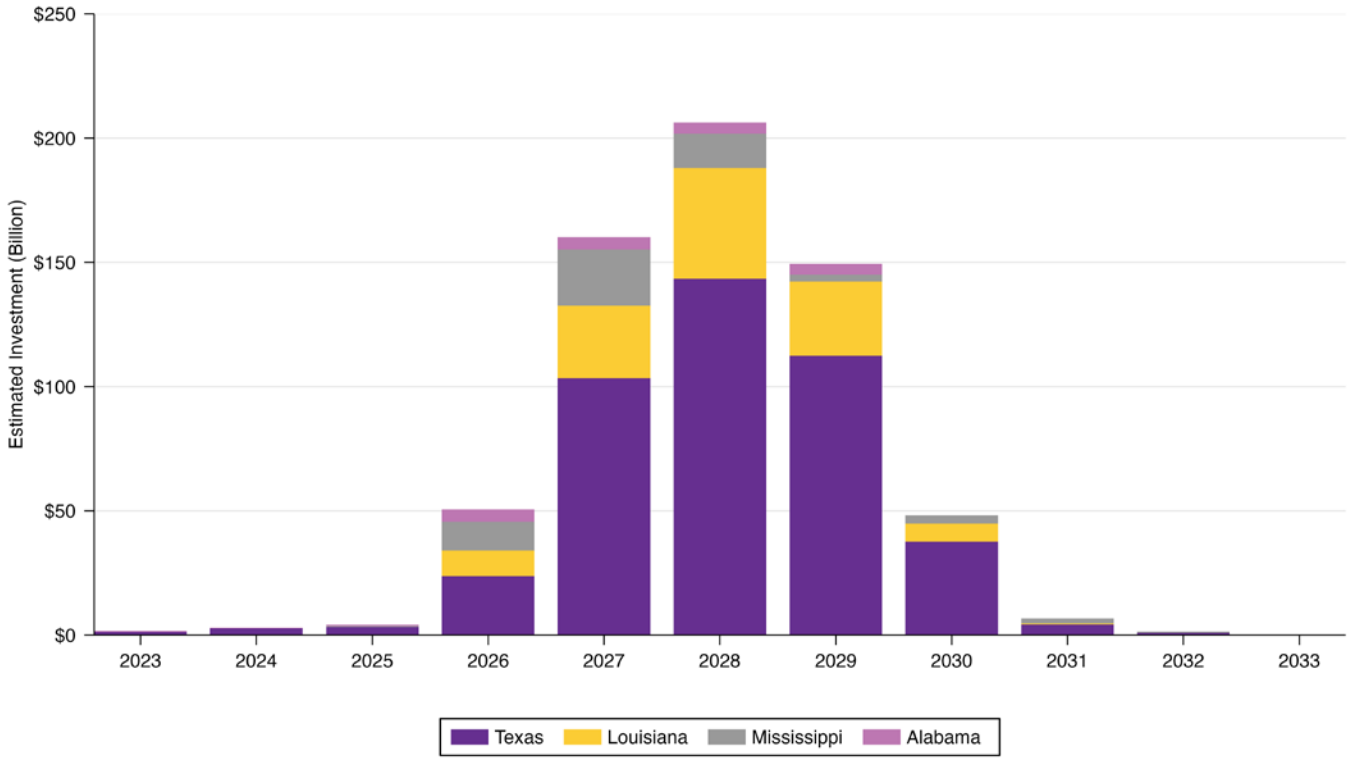


Source: Kubiak, E. (n.d.). Compute Atlas [Data set]. https://doi.org/10.5281/zenodo.22284476, Author's construct, Aterio Database.

The magnitude of this investment reflects the rapid expansion and adoption of hyperscale data centers, particularly those supporting AI, cloud computing, crypto mining, and other energy-intensive computing activities. As shown in Figure 18, annual projected investment is anticipated to peak in 2028 at approximately $206 billion, with substantial investment also anticipated in 2027 and 2029. However, the realization of these investments remains dependent on the availability of electric generation and transmission capacity, infrastructure development, and the ability of developers to secure the necessary financing and regulatory approvals.[74]

[74] E. Kubiak, Compute Atlas (data set), Zenodo.

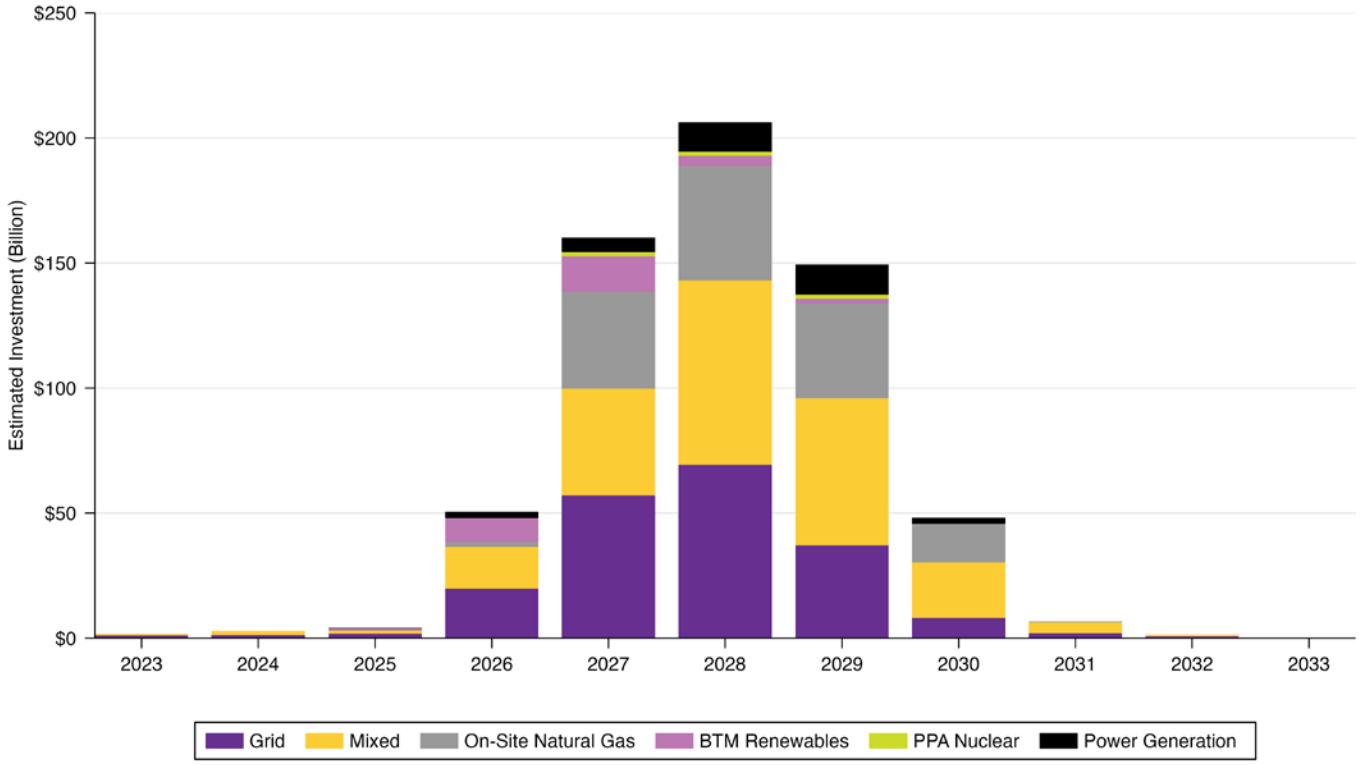
Figure 18: Regional data center investment



Source: Kubiak, E. (n.d.). Compute Atlas [Data set]. https://doi.org/10.5281/zenodo.22284476, Author's construct, Aterio Database.

The rapid expansion of data centers is also changing how these facilities secure their electricity requirements. As shown in Figure 19, a substantial portion of projected data center investment is associated with facilities relying on traditional grid connections, mixed grid and behind-the-meter (BTM) arrangements, and on-site natural gas generation. While grid-connected facilities continue to account for significant investment, mixed grid and BTM arrangements and on-site generation also represent substantial components of the regional investment outlook. Investments associated with BTM renewable energy and nuclear power purchase agreements (PPAs) account for comparatively smaller portions of the total.

Figure 19: Regional data center investments by energy source



Source: Kubiak, E. (n.d.). Compute Atlas [Data set]. https://doi.org/10.5281/zenodo.22284476, Author's construct, Aterio Database.[75]

Note: The Mixed category indicates that the data center is connected to the grid and has a behind-the-meter (BTM) component. Covers data center and crypto mining capacity entering service 2026–2031 (85.6 GW). Excludes 15.7 GW of dedicated power generation, 4.2 GW in service before 2026, and 2.9 GW entering service after 2031, which together bridge to the 108.4 GW.

The substantial investment associated with on-site natural gas generation and mixed power arrangements highlights the growing importance of alternative electricity supply strategies for data center development. These developments have important implications for the Gulf Coast's natural gas infrastructure, as additional generating facilities may require increased pipeline capacity and natural gas transportation services. Collectively, these developments suggest that the expansion of data centers will have implications extending well beyond the facilities themselves, creating additional opportunities for investment in electric generation, transmission, and natural gas transportation infrastructure. This emerging source of energy demand further reinforces the Gulf Coast's role as a major center for energy-related development.

[75] Aterio, "US Data Center Locations and Power Demand," Aterio Insights, dashboard/dataset, 2025.

6. Downstream Market Conditions

6.1 Refined Products

Gulf Coast refiners have benefited from increased demand for U.S. refined products amid disruptions to global energy supplies. In 2026, the conflict in the Middle East strengthened export opportunities and refining margins as overseas markets sought alternative supplies. These conditions supported high utilization of the region's refining capacity.[76] Weather conditions also shaped refinery operations, with winter storms posing risks to production and a slow start to the 2026 Atlantic hurricane season providing a comparatively favorable operating environment.

Winter Storm Fern in January 2026 was not accompanied by the sharp decline in Gulf Coast refinery utilization observed during Winter Storm Enzo a year earlier. During Enzo, weekly utilization fell from 92.5 percent in the week ending January 10, 2025, to 79.1 percent in the week ending January 24, a decline of 13.4 percentage points. By comparison, utilization increased from 90.5 percent in the week ending January 23, 2026, to 92.2 percent in the week ending January 30, which encompassed Fern. Although individual facilities may have experienced disruptions, the regional utilization data indicate a substantially smaller aggregate impact during the 2026 storm.[77]

The Atlantic hurricane season also caused minimal disruption. There were ten named storms and one hurricane. Three of these storms passed through the Gulf Coast region. The slow season was attributed in part to El Niño conditions, which tend to suppress Atlantic hurricane activity. The National Oceanic and Atmospheric Administration (NOAA) expects El Niño to persist through spring 2027, with a transition to ENSO-neutral conditions favored by summer, suggesting that this suppressing influence may not persist through the 2027 hurricane season.[78]

As shown in Figure 20, monthly Gulf Coast refinery utilization recovered from an early-year decline and remained high through the summer of 2026. Utilization averaged 89.4 percent in February before increasing to 91.6 percent in March and 90.1 percent in April. From May through August, monthly utilization exceeded 96 percent, indicating sustained intensive use of the region's refining capacity.[79]

Gulf Coast operable refining capacity changed little between February and July 2026, remaining near 9.9 million barrels per calendar day. This followed a decline of less than 2 percent in the region's capacity during 2025. Nationally, operable refining capacity fell by approximately 1 percent during 2025, reaching 18.2 million barrels per calendar day on January 1, 2026.[80,81]

[76] Reuters, "Iran war raises demand for US fuel, boosting Gulf Coast refining margins," April 9, 2026.

[77] U.S. Energy Information Administration (EIA), "Weekly Gulf Coast (PADD 3) Percent Utilization of Refinery Operable Capacity," 2025–2026.

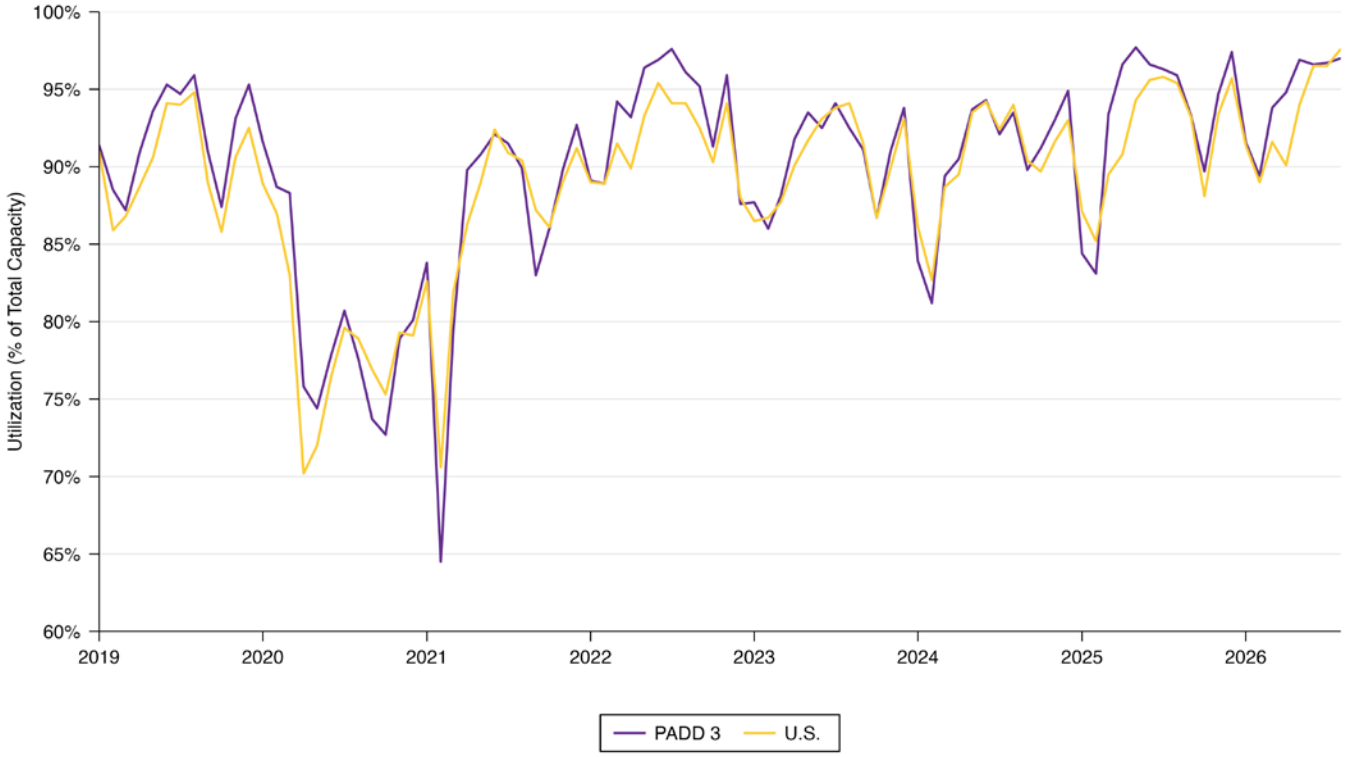
[78] NOAA Climate Prediction Center, "ENSO: Recent Evolution, Current Status and Predictions," outlook updated October 8, 2026.

[79] EIA, "Weekly Gulf Coast (PADD 3) Percent Utilization of Refinery Operable Capacity," January–August 2026. Same series as footnote 77.

[80] EIA, "Gulf Coast (PADD 3) Refinery Utilization and Capacity," monthly data, February–July 2026.

[81] EIA, "U.S. refining capacity decreased during 2025," June 29, 2026.

Figure 20: U.S. and PADD 3 monthly refining utilization



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

The increase in fuel prices during the Iran conflict has coincided with a substantial widening of U.S. refining crack spreads. A 3-2-1 crack spread approximates the difference between the value of two barrels of gasoline and one barrel of distillate fuel and the cost of three barrels of crude oil. Expressed per gallon, it provides an indicator of gross refining margins before operating and other costs.

As shown in Figure 21, the Gulf Coast WTI crack spread rose sharply in early 2026 alongside retail gasoline and diesel prices. Across four regional benchmarks, crack spreads averaged $1.32 per gallon from March 2026 onward—roughly 2.3 to 3.5 times their respective 10-year averages. The increase similarly occurred across other crack spread benchmarks, indicating that elevated spreads extended beyond a single regional market or crude benchmark.

These wider spreads indicate that refined-product values increased relative to crude input costs, improving gross refining margins. For Louisiana's refining industry, this represents a potentially favorable operating environment, although higher fuel prices increase costs for households and businesses. Actual refinery profitability, however, also depends on operating expenses, utilization, maintenance, and each facility's crude inputs and product mix.

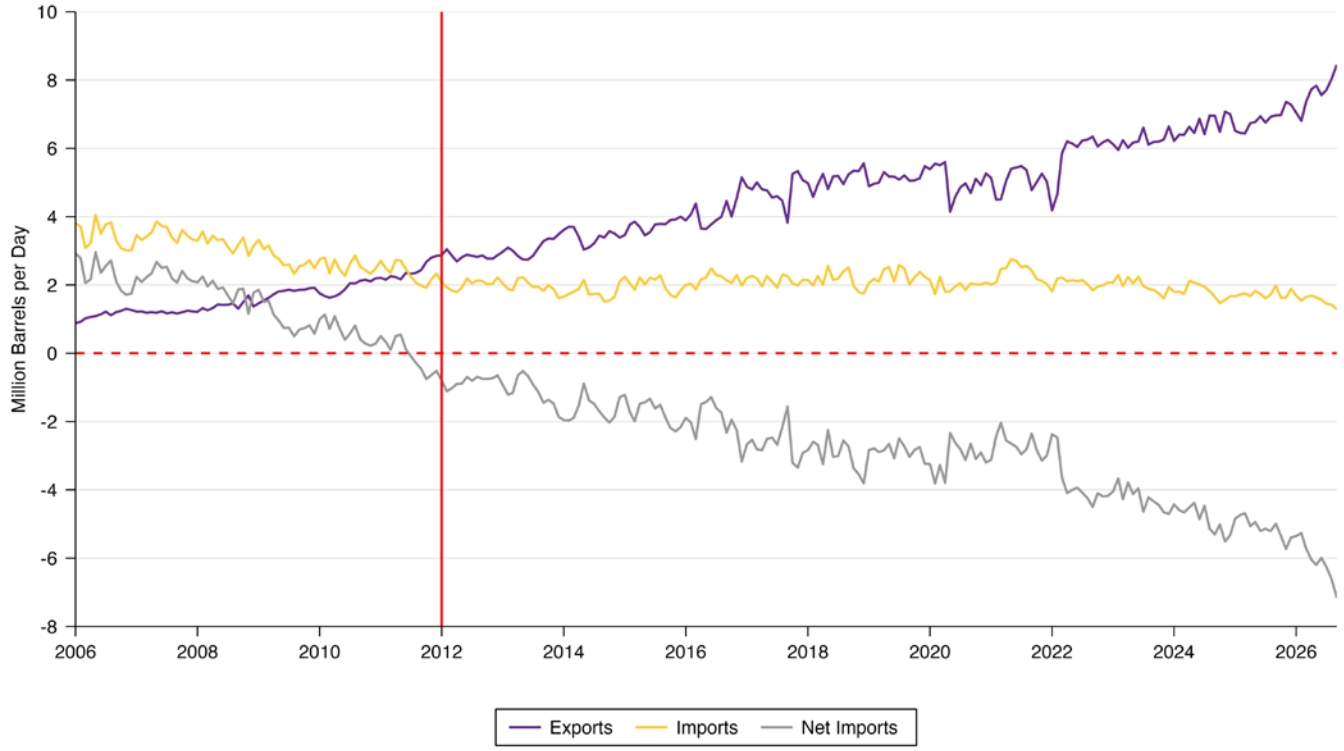
Figure 21: Retail gasoline and diesel prices and refinery crack spread



Source: EIA, Bloomberg, 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 22, refined product trade trends observed in the last few years' GCEOs 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 8 MMbbl/d, and net exports have hovered around 6–7 MMbbl/d in 2026. Disruptions and uncertainties in global energy markets will likely reinforce the U.S. export position in global markets, with potential for modest growth opportunities.

Figure 22: U.S. refined products trade

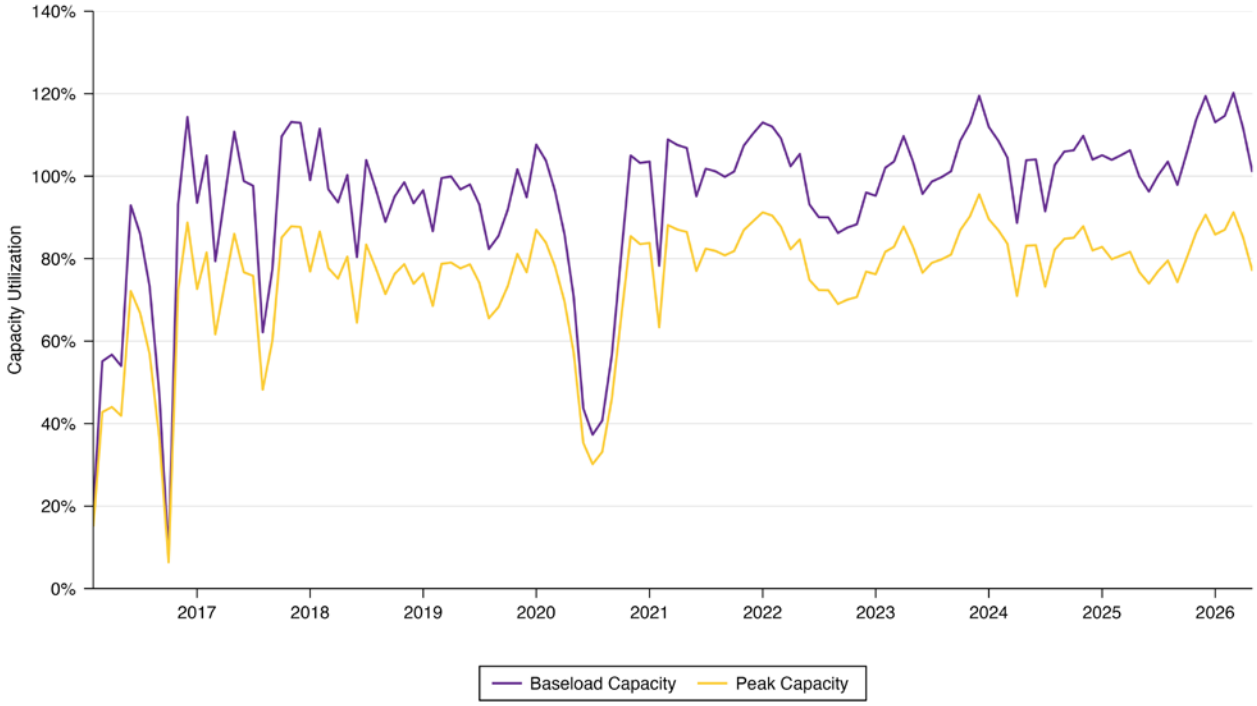


Source: U.S. Energy Information Administration.

6.2 Liquefied Natural Gas

Henry Hub prices have shown no increase following the outbreak of the Iran conflict, while European TTF and Asian JKM prices have risen, widening export margins for U.S. LNG. However, liquefaction facilities are already operating near capacity, limiting their ability to increase exports in response to higher international prices. Figure 23 measures utilization by dividing LNG exports by baseload and peak liquefaction capacities. Exports frequently exceed 100 percent of baseload capacity, which represents output under normal operating conditions. Peak capacity reflects maximum output under optimal conditions and therefore provides an upper benchmark. Utilization below 100 percent of peak capacity does not necessarily indicate readily available capacity, since optimal conditions may not be sustained continuously.

Figure 23: LNG export capacity utilization



Source: U.S. Energy Information Administration.

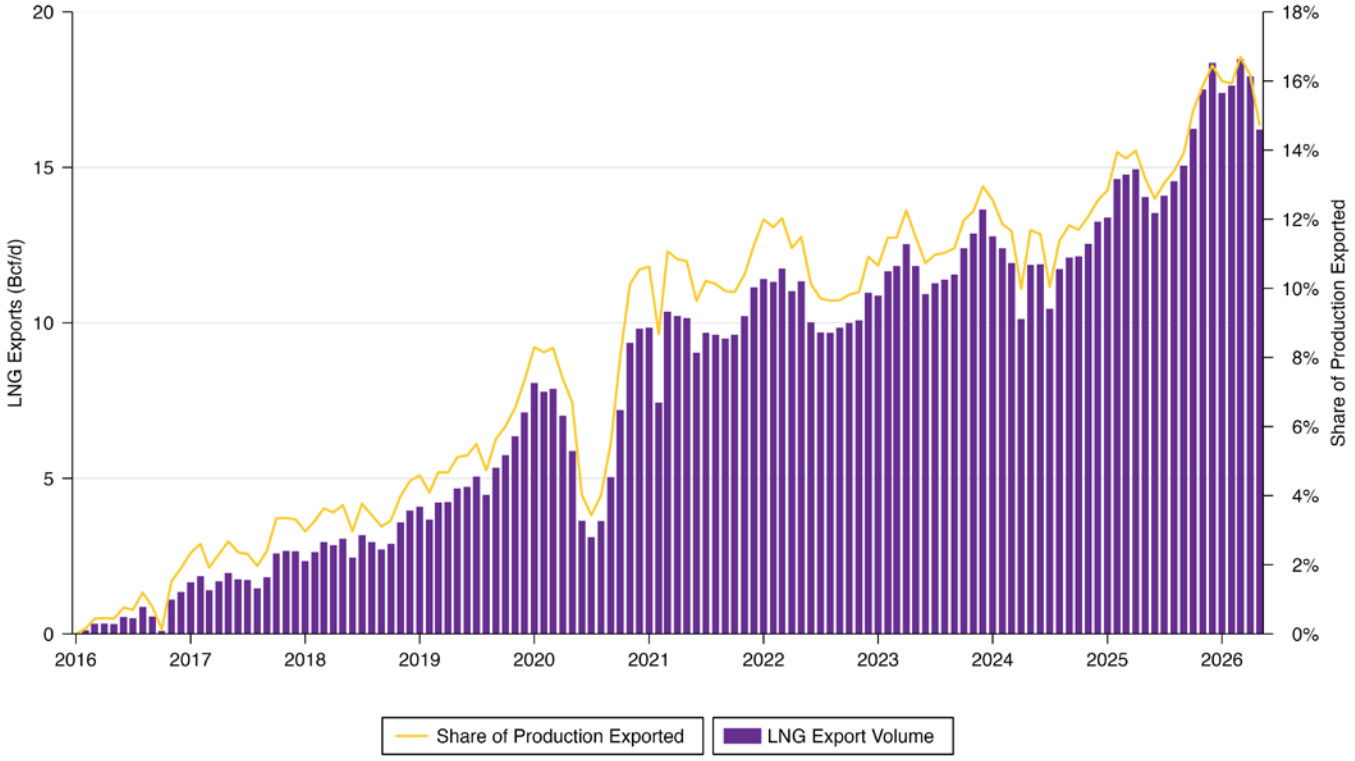
As shown in Figure 23, U.S. facilities operating or commissioning represent 14.29 Bcf/d of baseload liquefaction capacity and 19.08 Bcf/d of peak capacity. Average exports of 15.24 Bcf/d in 2025 exceeded this baseload benchmark, suggesting intensive use of existing infrastructure. However, these figures do not provide a precise utilization rate because the capacity totals include the full capacity of commissioning projects that were not available throughout the year.

As shown in Figure 24, U.S. LNG exports totaled approximately 5.56 trillion cubic feet in 2025, averaging 15.24 Bcf/d. Louisiana's Sabine Pass, Cameron, Calcasieu Pass, and Plaquemines facilities accounted for approximately 3.55 trillion cubic feet, or 63.8 percent of the national total, averaging 9.73 Bcf/d. Freeport LNG and Corpus Christi LNG in Texas also contributed to Gulf Coast exports. Europe and Asia received approximately 84 percent of Louisiana's LNG exports, underscoring the industry's exposure to overseas market conditions.

Projects under construction represent an additional 14.96 Bcf/d of baseload capacity, with listed completion dates extending through 2031. Louisiana projects account for 5.92 Bcf/d of these additions: Venture Global's CP2, Woodside Louisiana LNG Phase 1, and Commonwealth LNG. Together, these projects would expand Louisiana's baseload capacity by approximately 64 percent relative to the 9.27 Bcf/d represented by facilities operating or commissioning.

As these projects enter service, additional exports will increase domestic natural gas demand and expand the volume that can reach international markets. The effect on Henry Hub prices will depend on how quickly U.S. production and pipeline infrastructure accommodate that demand.

Figure 24: U.S. liquefied natural gas exports



Source: U.S. Energy Information Administration.

7. Federal Policy

For the Gulf Coast in 2027, the result is a sharper version of the dynamic the 2026 GCEO described: strong global demand for the region's crude, refined products, and LNG, paired with greater policy and geopolitical volatility.

Federal energy policy in 2026 has shifted from setting long-run direction to managing the largest oil supply disruption on record. The U.S.–Israel conflict with Iran, which began February 28, 2026, closed most traffic through the Strait of Hormuz and pushed Brent crude to a daily high of $131 per barrel on September 15.[82] Washington has answered with record strategic stock releases, shipping waivers, sanctions relief for Russia, and a push to restore Venezuelan supply, while continuing its "energy dominance" agenda of expanded leasing, LNG approvals, and deregulation coupled with expedited timelines.

In Congress, a bipartisan permitting and transmission bill negotiated by key senators and the White House with significant implications for energy development was introduced on September 30, 2026. The Bipartisan American Affordability and Jobs Act of 2026 (BAAJA; S. 5653) remains pending in the Senate; a floor vote is expected after the November 3 midterm elections.

7.1 The Policy Baseline: From Transition to Dominance

The federal framework entering 2026 was already a sharp break from the prior administration. The Biden administration prioritized an energy transition built on the 2021 Infrastructure Investment and Jobs Act and the 2022 IRA, held three offshore lease sales, and paused LNG export approvals to non-free-trade countries.[83]

The Trump administration lifted the LNG pause on its first day back in office and created the National Energy Dominance Council (NEDC) in February 2025, chaired by Interior Secretary Doug Burgum with Energy Secretary Chris Wright as vice chair. The 2025 reconciliation law (the One Big Beautiful Bill Act or Working Families Tax Cut Act) cut wind and solar credits, ended the EV credit, lowered federal royalty rates, restored intangible drilling cost deductions, and mandated 30 Gulf of America lease sales.[84]

What changed in 2026 was the operating environment. An energy strategy built around greater domestic supply and lower prices has had to respond to a global supply imbalance. The administration has therefore combined short-term market interventions with its longer-term production agenda. For investors, the distinction is relevant: emergency actions may help stabilize a market in the near term, while longer-term investment decisions also depend on predictable rules and available infrastructure capacity.

7.2 Geopolitical Shocks Redraw Global Energy Flows

Three events now heavily influence energy markets: the Iran war, the Russia–Ukraine war, and the U.S. intervention in Venezuela's oil sector. Each has moved federal policy toward direct intervention in global supply.

Iran and the Strait of Hormuz

Before the war, roughly a fifth of global oil and LNG moved through the Strait of Hormuz. The IEA calls the closure the largest supply disruption in the history of the oil market, and oil prices rose more than 50 percent in March alone.

[82] U.S. Energy Information Administration, "Short-Term Energy Outlook: Global Oil Markets," October 6, 2026.

[83] U.S. Department of Energy, "U.S. Department of Energy Reverses Biden LNG Pause," January 20, 2025.

[84] The White House, "Fact Sheet: President Donald J. Trump Establishes the National Energy Dominance Council," February 14, 2025.

The physical shortfall is easing but far from resolved. The U.S. Department of Energy's EIA estimates Middle East crude shut-ins fell from a peak of 10.9 million barrels per day (b/d) in May to 4.8 million b/d in September, and forecasts 4.5 million b/d in the fourth quarter. EIA's October outlook puts Brent at $105 in the fourth quarter of 2026 and $84 in 2027, with most regional output restored by mid-2027.[85]

The IEA's October Oil Market Report projects 2026 world demand falling 2.6 million b/d to 102.4 million b/d, while supply falls 5.8 million b/d. It expects the market to stay in deficit through year-end and middle-distillate supply (jet fuel, light heating oil, and diesel) to stay tight well into 2027. Diesel is the pressure point: U.S. retail diesel averaged $6.29 per gallon in September, and East Coast distillate stocks were 32 percent below their five-year average.[86]

For the Gulf Coast, the war has made the region an increasingly important swing supplier of refined products and LNG. EIA projects U.S. net petroleum exports rising from 2.9 million b/d in 2025 to 4.3 million b/d in 2026.[87] Qatar's LNG exports from April through September fell almost 90 percent year over year, and Gulf Coast terminals have absorbed much of that demand.[88]

Russia and Ukraine

Federal policy toward Russian energy has swung twice in a month. On September 18, 2026, the president signed the Lindsey O. Graham Sanctioning Russia and Iran Act of 2026, after an 86-vote Senate tally and a 262–159 House vote. The law authorizes tariffs of up to 100 percent on the five largest buyers of Russian oil and gas, up to 500 percent on Russian goods, sanctions on the shadow tanker fleet, and a five-year extension of the Iran Sanctions Act.[89]

In an effort to help establish conditions for peace negotiations with Russia, President Trump signed an executive order on October 16 to suspend some of the law's specific sanctions and duties. The administration had already lifted sanctions on Russian diesel exports and pressed Kyiv to halt drone strikes on Russian refineries, seeking to ease fuel prices before the midterms. The European Union, by contrast, is preparing its 22nd sanctions package.

The Gulf Coast implications run in two directions. Russian diesel returning to the market would release some pressure on distillate demand from Gulf Coast refiners. A durable peace with sanctions relief would bring more Russian crude and gas back to market, but Europe's shift to U.S. LNG since 2022 appears structural, reinforced this year by the loss of Qatari supply.

Venezuela

Venezuela has seen a significant pendulum swing. The country has moved from a sanctioned supplier to a U.S.-directed one. After a December 2025 naval blockade, U.S. forces captured Nicolás Maduro in early January 2026. The U.S. Department of the Treasury then issued general licenses allowing BP, Eni, Repsol, and Shell to re-engage, and authorized traders Vitol and Trafigura to export Venezuelan crude alongside Chevron.

On August 28, the administration announced an agreement under which Venezuela's interim authorities granted North American Blue Energy Partners (NABEP) 100-year concessions on 17 fields holding about 65 billion barrels of proven reserves. The U.S. holds a veto over NABEP directors, a majority of whom

[85] U.S. Energy Information Administration, "Global Oil Markets," Short-Term Energy Outlook, October 6, 2026.
[86] International Energy Agency, Oil Market Report: October 2026, October 14, 2026.
[87] Includes crude oil and petroleum products.
[88] U.S. Energy Information Administration, "Global Oil Markets," Short-Term Energy Outlook, October 6, 2026.
[89] United States Senate, S. 5025, 119th Cong. (2025–2026), legislative record.

must be U.S. citizens, and the company plans to raise up to $100 billion for rehabilitation. Chevron separately committed $7 billion to lift its joint-venture output from about 280,000 b/d to 600,000 b/d by 2031.[90]

Venezuelan production has recovered to roughly 1.2–1.25 million b/d, and exports to the U.S. reached a seven-year high of 786,000 b/d in July. This is among the most direct Gulf Coast effects of 2026 geopolitical developments: Venezuela's extra-heavy crude is the feedstock many Gulf Coast coking refineries were built to run.[91]

7.3 Domestic Production, Exports and Emergency Supply Measures

U.S. output keeps setting records. EIA's October outlook shows the gains coming mainly from natural gas and LNG.

LNG: the Gulf Coast fills Qatar's gap

U.S. LNG exports are running about 14 percent above last year, and the U.S. remained the top global supplier through the third quarter. Venture Global's Plaquemines terminal posted a 240 percent year-over-year jump in export volumes, and Sabine Pass loaded about a quarter of U.S. cargoes in the first quarter.[92]

The recent global energy supply shifts have also accelerated long-term commitments. Caturus reached a final investment decision on the 9.5-million-tonne Commonwealth LNG terminal in Cameron Parish on May 15, a roughly $13 billion project targeting 2030 operations. On October 22, QatarEnergy itself signed agreements to buy up to 4 million tonnes per year from Cheniere through 2054, routing supply around Hormuz. Woodside's Louisiana LNG and Venture Global's CP2 remain under construction.[93]

Ample domestic gas has kept that export growth from driving up U.S. prices. EIA expects storage to reach about 3,850 Bcf at the end of October, 2 percent above the five-year average, and Henry Hub to average $3.16 per MMBtu in 2027.[94]

Offshore leasing

Interior has held three of the 30 Gulf of America lease sales mandated by the 2025 reconciliation law (through 2040). By contrast, the Biden administration held three over the four-year presidential term—the fewest under any administration since federal offshore leasing began.

A predictable sale calendar can reduce uncertainty about future access to offshore acreage and support longer-term exploration planning, leading to increased investment in the Gulf. While hundreds of millions of dollars in high bids were received across the three sales, the March 11, 2026 sale was the weakest Gulf sale in at least a decade, and an Alaska Cook Inlet sale drew no bids, even as crude prices surged. The muted response may indicate that operators are reluctant to commit long-lived deepwater capital on a war premium and an uncertain energy policy future.

Interior is also restructuring offshore oversight. Secretary's Order 3451, issued July 10, 2026, merges the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement into a new Marine Minerals Administration, reversing the post-Deepwater Horizon separation of leasing and

[90] The White House, "Fact Sheet: President Donald J. Trump Announces Historic Oil Agreement to Secure American Energy Dominance and Drive Venezuela's Economic Recovery," August 31, 2026.

[91] U.S. Energy Information Administration, Petroleum and Other Liquids Data, U.S. imports by country.

[92] Reuters, "US Exporters Are Plugging Qatar-Sized LNG Supply Hole—For Now," April 24, 2026.

[93] Louisiana Economic Development, "Louisiana Surpasses $100 Billion in New Investment Following Commonwealth LNG Final Investment Decision," 2026.

[94] U.S. Energy Information Administration, "EIA Expects a Mixed Picture for Winter Fuel Costs This Year," October 6, 2026.

safety enforcement. A draft proposed 2026–2031 offshore leasing program, published in November 2025, remains in development, with the "1st Analysis and Proposal" completed.[95]

Strategic Petroleum Reserve and fuel logistics

The administration has leaned heavily on the Gulf Coast's emergency infrastructure. The U.S. Department of Energy (DOE) committed 172 million barrels from the Strategic Petroleum Reserve (SPR) to the IEA's March collective action, structured as exchanges that return about 1.2 barrels for each barrel released by the end of 2027; a further 40-million-barrel exchange followed on September 29. EIA projects SPR inventories falling to about 243 million barrels by year-end, then rebuilding to about 346 million barrels by the end of 2027 as exchange barrels return to the four Gulf Coast storage sites.[96]

A significant near-term policy risk for Gulf Coast refiners is a possible diesel export ban. The administration and some members of Congress are reportedly considering restrictions, and one House bill (H.R. 10422) would trigger a ban automatically whenever diesel averages more than $5.00 per gallon for two weeks. Analysts warn that refiners could respond by cutting runs, which could raise prices for gasoline and jet fuel.

7.4 Demand Growth and New Generation

Electricity demand growth has moved from projection to reality, and federal policy now treats grid capacity as a national-security issue. EIA's Annual Energy Outlook 2026, released April 8, 2026, projects U.S. electricity consumption growing 0.9 percent to 1.6 percent a year through 2050, with data center load the dominant driver, even as total energy use stays roughly flat.[97]

Near-term data confirm the trend. Electricity consumption in the third quarter of 2026 rose 4 percent from a year earlier, and EIA expects commercial-sector demand, which includes data centers, to grow 2.8 percent in 2027, with industrial demand up 2.7 percent. Each of the Gulf Coast states has announced large-scale data center projects—pairing domestic energy resources in the region with the intense power consumption of the facilities.[98]

Electricity rates, water use, land impacts, and grid reliability have made data center growth a policy issue as much as an economic development opportunity. Federal and state officials have pressed large customers to pay the infrastructure costs they create. Some developers have committed to dedicated generation or long-term power purchases; those commitments should not be assumed for every announced project. A key question is whether large-load customers cover the infrastructure costs attributable to their projects without shifting stranded-asset risks to existing utility customers.

What is being built

Developers planned a record 86 gigawatts (GW) of new utility-scale capacity for 2026, up from 53 GW in 2025: 43.4 GW of solar, 24.3 GW of batteries, 11.8 GW of wind, and 6.3 GW of natural gas. Gas remains the backbone of generation at about 40 percent of output, but near-term additions of dispatchable power continue to diversify.[99]

Louisiana shows where large-load-driven gas demand is heading. On March 27, Entergy Louisiana and

[95] U.S. Department of the Interior, Secretary's Order 3451, "Establishment of the Marine Minerals Administration," July 10, 2026; "Transition to the Marine Minerals Administration."

[96] U.S. Department of Energy, "United States to Release 172 Million Barrels of Oil From the Strategic Petroleum Reserve," March 11, 2026.

[97] U.S. Energy Information Administration, Annual Energy Outlook 2026, April 2026.

[98] Reuters, "US Power Use to Beat Record Highs in 2026, 2027 as AI Use Surges, EIA Says," October 6, 2026.

[99] U.S. Energy Information Administration, Today in Energy, planned 2026 electric generating capacity.

Meta announced seven additional CCGT power plants totaling 5.2 GW for the Hyperion campus in Richland Parish, bringing the planned total to 10 plants and more than 7 GW, at a cost near $12.9 billion. That build-out equals more than a 30 percent increase in Louisiana's grid capacity and includes about 240 miles of new transmission; the seven new plants still require Louisiana Public Service Commission approval.[100]

The Meta agreement follows the White House's March 4, 2026 Ratepayer Protection Pledge, in which seven large technology companies committed to build, provide, or buy the power their data centers require. Under this pledge, signatory companies committed to cover the full cost of new generation resources and power delivery infrastructure upgrades required to serve their data centers, as well as to pay agreed rates for power and infrastructure whether or not they use the electricity.[101]

Keeping existing plants online

DOE has used emergency authority under Section 202(c) of the Federal Power Act to block planned retirements of electricity facilities on an unprecedented scale: 16 orders in 2025 and at least 35 more by mid-June 2026, covering coal and other fossil plants in Michigan, Pennsylvania, Colorado, Washington, Florida, and Indiana. A February 11, 2026 executive order, "Strengthening United States National Defense With America's Beautiful Clean Coal Power Generation Fleet," frames coal capacity as a defense asset.

Nuclear

The administration met its first nuclear deployment milestone early. Executive Order 14301 set a goal of three advanced reactors reaching criticality by July 4, 2026, and four DOE-authorized test reactors did so. All four were zero-power research demonstrations rather than commercial units, but they may shorten the path to the Nuclear Regulatory Commission licensing that grid-scale advanced reactors will need.[102] Most of the original 11-project pilot cohort has not yet reached the milestone.

7.5 Permitting and Transmission: The Bipartisan American Affordability and Jobs Act

One consequential piece of pending federal energy legislation is S. 5653, the BAAJA. Introduced September 30 by the chairs and ranking members of the two committees of jurisdiction, Senators Shelley Moore Capito (R-W.Va.) and Sheldon Whitehouse (D-R.I.) of the Committee on Environment and Public Works, and Senators Mike Lee (R-Utah) and Martin Heinrich (D-N.M.) of the Committee on Energy and Natural Resources, the 417-page bill builds on the Fiscal Responsibility Act's environmental streamlining provisions, the Energy Permitting Reform Act of 2024, and the House-passed SPEED Act of 2025.

The legislation would change National Environmental Policy Act (NEPA) procedures, narrow some litigation windows, provide greater certainty for permits that have been issued, and address reviews under the Clean Water Act, Endangered Species Act, and National Historic Preservation Act. It also proposes changes affecting transmission development and the allocation of transmission costs attributable to data centers. Beyond shortening review timelines, the bill would limit federal agencies' ability to revoke or suspend issued permits, subject to specified exceptions, and provide remedies for project sponsors when agencies improperly interfere with approved projects. These provisions seek to reduce regulatory uncertainty that can affect whether and when projects proceed to financing, construction, and operation. The proposal remains pending legislation for the time being, not current law.

[100] Bloomberg News, "Meta Funds Seven Entergy Gas Plants to Power Biggest Data Center," March 27, 2026.

[101] The White House, "Ratepayer Protection Pledge," March 4, 2026.

[102] U.S. Department of Energy, "FACT SHEET: The Golden Era of American Nuclear Energy Has Arrived," July 25, 2026.

7.6 Federal Actions by Executive Branch – Not Congress

Much of the Trump administration's energy agenda has been advanced through executive action and agency decisions rather than new legislation. Those tools can change priorities quickly, but individual actions remain subject to statutory limits, judicial review, and potential reversal by future administrations.

National Energy Dominance Council

The National Energy Dominance Council has served as a coordinating mechanism for federal energy priorities across departments. The NEDC has been a key player in ensuring consistency among federal policies—whether DOE, Interior, EPA, FERC, and other agencies reach consistent decisions on leasing, infrastructure, reliability, and project reviews. Coordination among agencies may reduce delays arising from overlapping reviews, although projects remain subject to statutory permitting requirements and commercial constraints.

Department of Energy and FERC

DOE has accelerated attention to LNG exports, grid reliability, energy security, and advanced nuclear technology, while using emergency authority to retain selected existing power plants. FERC's transmission planning, interconnection and large-load proceedings affect whether new generation and data centers can connect to the grid, how quickly, and at whose expense. Keeping a generator available in an emergency is not the same as adding a new generation resource or expanding the transmission system.

Department of the Interior

Interior's offshore leasing schedule, royalty terms, and oversight reorganization have particular significance for the Gulf Coast. Onshore oil and gas, critical minerals, and federal land approvals also affect domestic supply chains. Greater acreage access and more predictable schedules improve the opportunity to invest, but lease sales, exploration, discoveries, and producing wells occur on different timelines.

Environmental Protection Agency and federal permitting agencies

EPA has pursued significant changes to federal emissions and other regulatory programs, while federal permitting agencies have revised review procedures following recent statutory changes and court decisions. One area of focused regulatory relief is the reconsideration of the Biden administration's methane regulations related to oil and gas production. Narrow revisions to the Biden-era rules were finalized in April of 2026, and on October 27, 2026, the EPA proposed broader changes to 2024 New Source Performance Standards and existing-source guidelines, including the elimination of the Super Emitter Program, modifications to leak detection requirements, and additional flexibility for smaller and conventional wells, associated gas management, and emissions-control equipment.[103] This builds upon the congressional repeal of the methane waste emissions charge. The effects of regulatory changes depend partly on whether rules are proposed, finalized, or subject to litigation. For industrial investors, regulatory consistency and defensible permits can matter as much as the direction of an individual rule. The Gulf Coast's refineries, petrochemical plants, ports, and power projects depend on coordinated federal and state implementation.

The common issue is the difference between speed and durability. Executive orders, emergency findings, waivers, and revised agency procedures can change the near-term trajectory of investment, but their permanence varies. The predictability of statutory requirements and the timing and consistency of

[103] U.S. Environmental Protection Agency, "EPA Proposes Major New Revisions to Burdensome, Unworkable Biden-era Oil and Natural Gas Regulations," October 27, 2026.

agency decisions can affect developers' financing decisions and construction schedules. The recently introduced permitting bill's project-certainty provisions seek to reduce uncertainty about the continued validity of project approvals.

7.7 Outlook for the Gulf Coast

The Gulf Coast has several advantages at a moment when global energy security and domestic electricity demand are changing rapidly: abundant natural resources, production and refining capacity, ports, pipelines, LNG terminals, industrial expertise, and a workforce accustomed to building complex infrastructure. But those advantages do not guarantee that the next investment will be made here. New energy projects must compete on cost, reliability, and the time required to obtain approvals and begin operating. Federal policies governing resource access, regulatory requirements, transmission and pipeline permitting, and electricity cost allocation can affect project costs, development timelines, and charges to existing customers. The economic effects of the region's energy resources depend on production costs, transportation and delivery capacity, system reliability, and the timing of infrastructure development.

8. Employment Outlook

8.1 Employment Forecasts

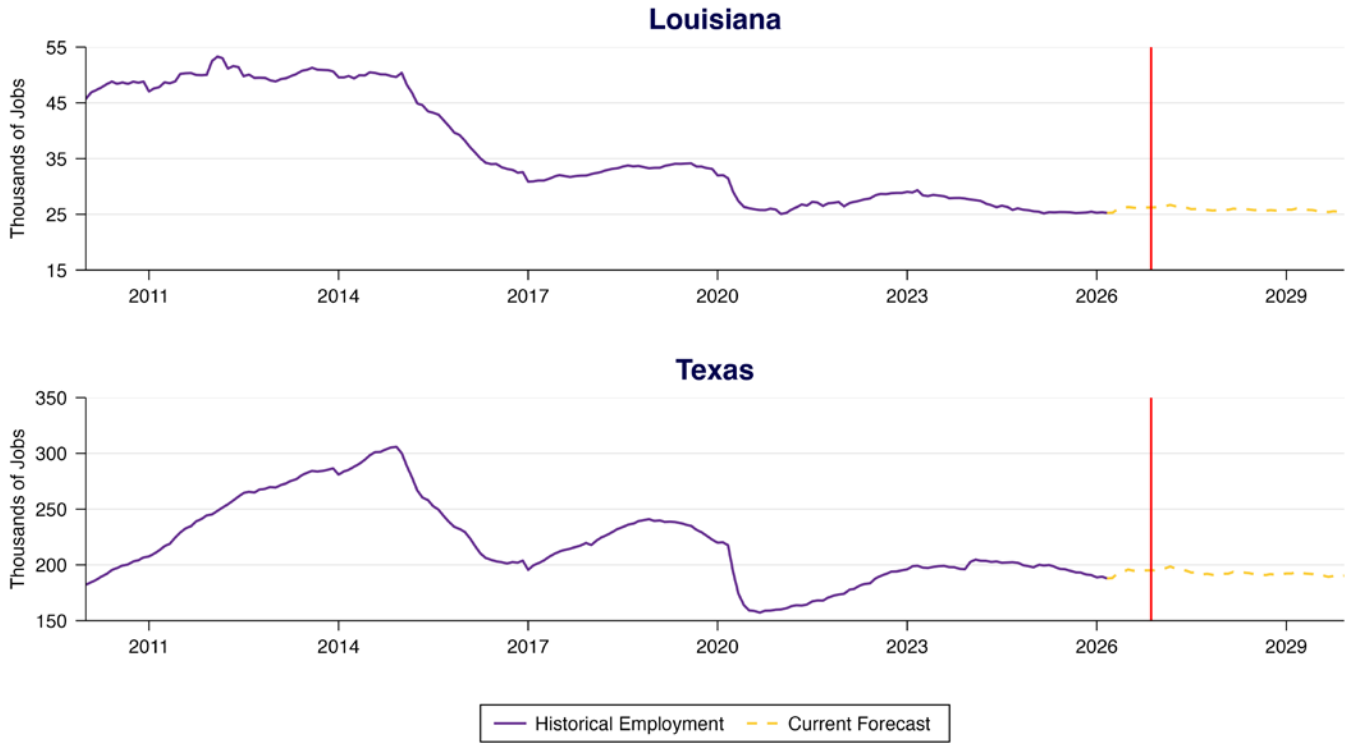
In this section of the GCEO, prior sections are synthesized into employment forecasts. Employment is forecast within two broad sectors: (1) upstream oil and gas extraction and services and (2) refining and chemical manufacturing. Sectors are identified based on the North American Industry Classification 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).[104] 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 2026 for both upstream and downstream employment. Thus, part of the "forecast" has already occurred; we just have not observed the labor market data.

Upstream oil and gas employment for both Louisiana and Texas exhibits three key patterns in historical data shown in Figure 25. The first key pattern is that Louisiana employment growth, pre-2015, was modest relative to the rapid growth in Texas employment. The second key pattern is the 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 17,000 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 third key pattern is the shock that 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 2026), the employment levels are still almost 26 percent lower than the pre-pandemic peak in Louisiana and about 20 percent below in Texas.

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

Figure 25: Upstream employment forecast



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

Figure 25 also shows the forecasted employment in the upstream oil and gas sectors for Louisiana and Texas. 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).

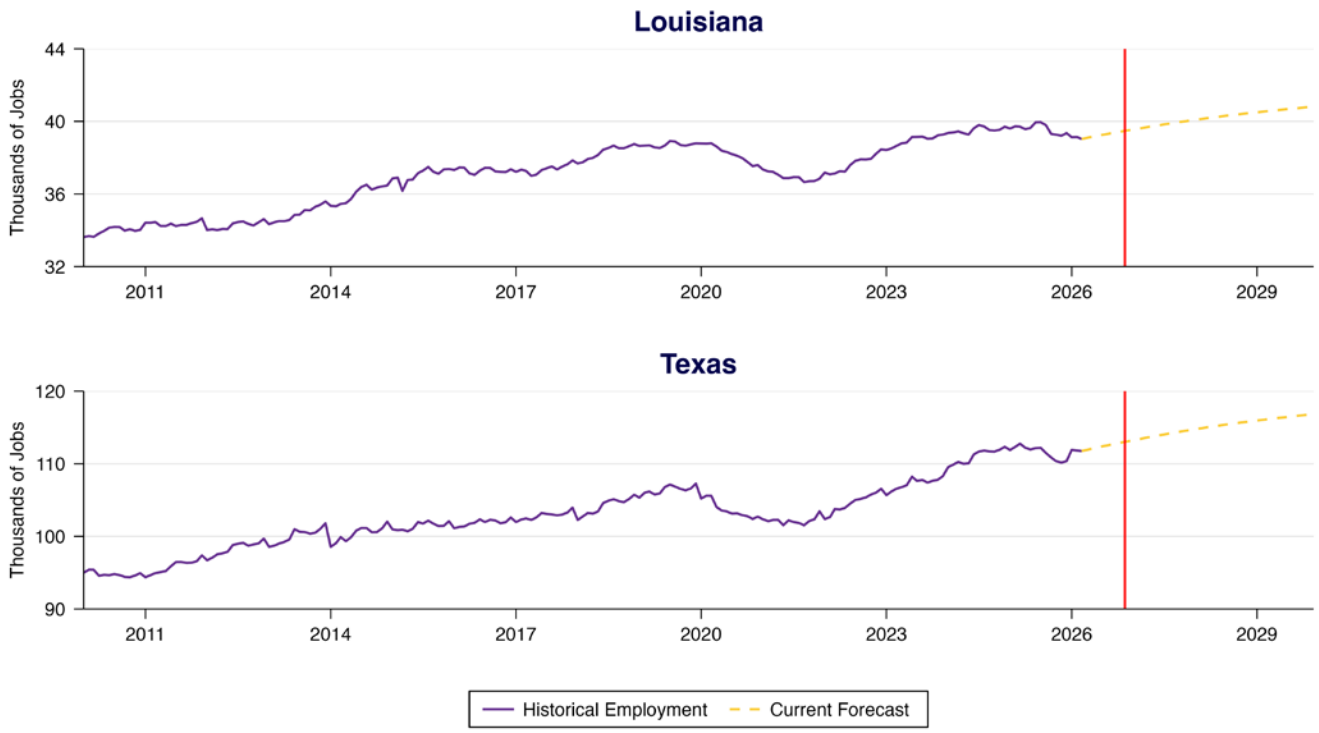
Overall, Louisiana upstream oil and gas employment is forecasted to remain relatively stable through the forecast horizon ending in 2029, with only modest gains over time. From January to December 2025, current employment data suggests that the sector lost approximately 55 jobs, or about a 0.2 percent decline (statistically flat). The forecast suggests that employment increased gradually through mid-2026 and will hold through early 2027 before easing back and 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 2029. Interestingly, employment at the end of the forecast horizon (December 2029) is about 320 jobs lower than the most recent month of data available (March 2026), a decline of about 1 percent, despite the sizable rise and fall in between. 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.

Texas upstream oil and gas employment declined over the course of 2025, falling by about 6,900 jobs, or roughly 4 percent, from January to December, and fell by a further 830 jobs (0.4 percent) from January to March 2026. The forecast anticipates a rebound through mid-2026, followed by a gradual, uneven decline for the remainder of the horizon that eases employment back toward roughly its starting level by 2029. Even with these cyclical fluctuations, employment at the end of the forecast horizon (December

2029) is projected to be about 2,400 jobs higher than the most recent month of data available (March 2026), an increase of about 1.3 percent.

Note that oil production in the Gulf Coast region is anticipated to remain relatively steady, edging down slightly over the forecast horizon, while natural gas production continues to rise. Despite this growth in gas output, upstream employment in Texas and Louisiana is projected to remain roughly flat. This illustrates the continued expected efficiency improvement of the sector.

Figure 26: Refining and chemical manufacturing employment forecast



Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, Industrial Tax Exemption Program (ITEP), and authors' forecast.

Historical data on refining and chemical manufacturing employment are shown in Figure 26. 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 26 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 continues its upward trajectory. Specifically, we estimate 470 new jobs will be gained from March to December 2026, an increase of about 1.2 percent. Note that part of this is still due to post-pandemic recovery, while another part is due to continued investment. By the end of 2026, GCEO estimates that Louisiana refining and chemical employment will have rebounded to the pre-pandemic peak and have added approximately 590 additional jobs above the pre-pandemic peak. From 2027 to 2029, GCEO estimates job growth of 1.4 percent to 0.9 percent, indicating continued expansion. Note that developments like data centers and new power generation discussed in prior sections are not included in these numbers.

Texas refining and chemical manufacturing employment exhibits a similar pattern to Louisiana. GCEO anticipates that Texas refining and chemical employment is forecasted to increase by approximately 1,360 jobs in 2026, 1,540 jobs in 2027, 1,220 jobs in 2028, and 980 jobs in 2029.

Discussions with companies consistently emphasized that substantial capital projects, including data centers and new power generation, are moving forward but are not included in these employment forecasts. These projects nonetheless compete for an already limited supply of skilled labor, constraining the pace of direct employment growth in the sectors forecasted here. Combined with the long-running trend toward improved operating efficiency, labor scarcity helps explain why projected employment gains remain modest despite continued investment activity.

9. Conclusion

The Gulf Coast remains a central region for U.S. energy production, processing, exports, and energy-intensive manufacturing. Abundant natural resources, established industrial infrastructure, deepwater ports, pipeline networks, LNG facilities, and a skilled workforce continue to support the region's role in global energy markets. Natural gas production, LNG export capacity, and demand for related infrastructure are expected to remain important sources of regional activity.

At the same time, the outlook is shaped by uncertainty. Geopolitical developments, commodity-price volatility, global economic conditions, financing costs, supply-chain constraints, and changes in federal and state policy can all affect project economics and development timelines. Announced investments should therefore not be interpreted as certain outcomes. The ability to secure reliable power, pipeline and transmission capacity, timely permits, and predictable regulatory treatment will be increasingly important in determining which projects ultimately move forward.

Electricity demand growth, particularly from data centers and other large loads, is emerging as an important new driver of regional investment. These developments may support additional investment in generation, transmission, and natural gas transportation infrastructure, but also raise questions about resource adequacy, cost allocation, and impacts on existing customers. The pace at which this demand materializes—and the manner in which it is served—will be a determinant of the *Gulf Coast Energy Outlook* that will be tracked in future years.

Finally, the employment forecasts underscore that rising investment and output do not necessarily translate into large direct employment gains. Continued improvements in operational efficiency, together with competition for a limited supply of skilled labor from data centers, power generation, and other capital projects, are expected to restrain employment growth in the sectors examined in this report. Overall, the Gulf Coast is well positioned to take advantage of growing global energy demand and growing domestic power demand, but the scale and timing of growth will depend on the region's ability to convert its underlying advantages into reliable, cost-competitive, and durable infrastructure development.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