

Southeast Supply Enhancement Market Study

prepared for

Transcontinental Gas Pipe Line Company, LLC

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Disclosure

This report has been commissioned by Transcontinental Gas Pipe Line Company, LLC (Transco), a subsidiary of The Williams Companies, Inc. This study has been funded in full by Transco. Levitan & Associates, Inc. (LAI) has performed an independent assessment of the need for the Southeast Supply Enhancement (SSE) project, how gas transported by SSE will be used, and the net impact of SSE on reasonably foreseeable greenhouse gas (GHG) emissions of natural gas infrastructure. The methods, findings and recommendations set forth in this report are strictly those of LAI. The findings and conclusions reached in this report are independent of any other work undertaken for other clients.

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Glossary

AEO	Annual Energy Outlook	LTRAs	Long-Term Reliability Assessments
BCF	Billion Cubic Feet	MDQ	Maximum Daily Quantity
BESS	Battery Energy Storage Systems	MDth	Thousand Dekatherms
BoA	Bank of America	MG0	Moderate Gas, Lower Carbon Pressure
CAGR	Compound Annual Growth Rate	MMcf	Million Cubic Feet
CC	Combined-Cycle	MSX	Mississippi Crossing
CDD	Cooling Degree Days	MVP	Mountain Valley Pipeline
CO₂	Carbon Dioxide	MW	Megawatt
CPCN	Certificate of Public Convenience and Necessity	MWh	Megawatt-hour
CSAPR	Cross-State Air Pollution Rule	NAAQS	National Ambient Air Quality Standards
CT	Combustion Turbine	NAICS	North American Industry Classification System
DEC	Duke Energy Carolinas, LLC	NCUC	North Carolina Utilities Commission
DEP	Duke Energy Progress, LLC	NOx	Nitrogen Oxides
DSM	Demand-side Management	OFO	Operational Flow Order
Dth	Dekatherm	PMI	Power Model Interface
EA	Environmental Assessment	RCI	Residential, Commercial, and Industrial
EBB	Electronic Bulletin Board	RFP	Request for Proposals
EE	Energy Efficiency	SC PSC	South Carolina Public Service Commission
EIA	Energy Information Administration	SEEM	Southeast Energy Exchange Market
ELCC	Effective Load Carrying Capability	SERC	Southeast Electric Reliability Council
EPRI	Electric Power Research Institute	SNG	Southern Natural Gas
ETNG	East Tennessee Natural Gas	SO₂	Sulfur Dioxide
FID	Final investment decision	SSE	Southeast Supply Enhancement
FT	Firm Transportation	SSE4	South System Expansion 4
GA PSC	Georgia Public Service Commission	Transco	Transcontinental Gas Pipe Line Company, LLC
GDP	Gross Domestic Product	TWh	Terawatt Hours
GHG	Greenhouse Gas	VACAR	Virginia-Carolinas
GPC	Georgia Power Company		
GPCM	Gas Pipeline Competition Model		
GW	Gigawatt		
GWh	Gigawatt-hour		
HDD	Heating Degree Days		
IPI	Initial Production Index		
IRPs	Integrated Resource Plans		
ITCS	NERC Interregional Transfer Capability Study		
LAI	Levitan & Associates, Inc.		
LDC	Local Distribution Company		
LNG	Liquefied Natural Gas		

Executive Summary

The purpose of this report is to provide information regarding the need for the SSE project, how gas transported by SSE will be used, and the net impact of SSE on reasonably foreseeable GHG emissions across the Southeast.

- Section 1 provides a survey of economic growth in the Carolinas and Georgia in order to establish how economic growth drives growing electricity demand.
- Section 2 identifies how Duke Energy Carolinas, LLC (DEC) and Southern Company Services, the primary SSE shippers, will use project capacity to meet electricity demand growth via new combined-cycle generation capacity, reviews the limitations of existing pipeline capacity into the Carolinas and Georgia, and explores the limitations of alternatives to meet the shippers' needs.
- In Sections 3 and 4, LAI uses electric system dispatch and gas transport modeling to determine the emissions and production cost impacts of SSE and the combined-cycle generation it enables.

The main observations and findings for each Section are addressed briefly in this Executive Summary. Additional detail underlying LAI's study approach and findings are presented in the individual Sections. The study region definitions differ slightly from an electric and gas perspective due to differences between utility service territories, but cover North Carolina, South Carolina, Georgia, and portions of Alabama and Mississippi.

Section 1: Economic and Manufacturing Growth are Driving Rapid Growth in Electricity Demand in the Carolinas and Georgia

In Section 1, LAI surveys economic growth in the study region and demonstrates how the rapid economic growth expected in Carolinas and Georgia drives growing electricity demand in Duke and Georgia Power's service territories.

Between 2023 and 2031, DEC and Duke Energy Progress, LLC (DEP, or collectively, Duke), forecasts that winter peak demand will grow at an annual rate of 2.1% per year. Georgia Power's winter peak is forecasted to grow at 5.5% per year.

Section 2: Existing Pipeline Capacity Cannot Meet Shippers' Needs for New and Existing Power Generation

In Section 2, LAI reviews the regulatory record supporting shippers' plans to build new gas-fired generation that relies on the SSE and identifies the larger trend towards additional gas demand for power generation in the Southeast. LAI analyzes firm transportation entitlements and scheduled flows data for the Transcontinental (Transco) and Southern Natural Gas (SNG) pipelines. This analysis shows the high subscription and utilization of these pipelines. Additionally, LAI reviews critical notices on Transco and demonstrates how often gas infrastructure is highly utilized, thereby warranting the transporter's notification to shippers of scheduling restrictions. Gas pricing data is also reviewed to show how constraints affect the value of delivered gas to shippers, as elevated gas prices often indicate high utilization of constrained

pipeline segments. LAI also evaluates alternatives to the SSE including alternative sources of natural gas, alternative generation resources and energy conservation. LAI concludes that each alternative source is insufficient. Duke and Georgia Power considered energy conservation and alternative generation resources in their resource planning and concluded that new gas-fired generation is needed to ensure reliability. Liquefied Natural Gas (LNG) and expanded capacity on other pipelines would increase supply in the region, but would not eliminate the need for the SSE, as LNG cannot supply the consistent volumes required by baseload gas-fired generation. Moreover, at the time of this study no other interstate pipelines serve both of the Carolinas. New firm transportation (FT) is also valuable for existing combined-cycle generation, some of which does not have backup fuel capability.

LAI's review shows that the shippers plan to add gas-fired generators to meet rising power demand. Duke expects to build three 1,360 MW combined-cycle plants with gas demand requirements of 705 MDth/d in the aggregate. Duke's contracted FT on SSE totals 1,000 MDth/d. Georgia Power requires substantial amounts of new capacity resources to come online from 2029 to 2031, and their base scenario for supply portfolio modeling that was provided to support their resource plan includes the addition of about 4.8 GW of gas-fired generation by 2031. Neighboring utilities also plan to add gas-fired generation. There are limited firm entitlement holders that have fungible capacity that shippers could acquire. Due to constraints north to south, new supply from the Mountain Valley Pipeline that Transco receives at the Cherrystone Interconnect and north to south flows on Transco near Station 165 are in part "bottled" and cannot reach the Carolinas and Georgia. Elevated pricing in Zone 5 South relative to other leading price benchmarks underscores the adverse price impact attributable to frequent congestion. Daily Transco Zone 5 South prices averaged \$6.59/MMBtu over the 2024-25 winter (December through February), as compared to the Marcellus production area Eastern Gas South index, which averaged \$3.55/MMBtu over the same period.

Section 3: SSE Incremental Deliverability Yields Economic Benefits

In Section 3, LAI reports the results of gas transportation modeling to simulate the price effects and flow impacts resulting from the addition of SSE. The incremental gas demand associated with the new generation proposed by Duke and Georgia Power is explicitly accounted for in the gas transportation model. This modeling was performed using RBAC Inc.'s Gas Pipeline Competition Model (GPCM), which simulates North America's interstate gas system using a series of zones and links between them. RBAC's Power Module Interface (PMI) add-on was used to share gas prices and demand between GPCM and electric system dispatch modeling in an iterative process.

The iterative electric- and gas-side modeling forecast shows that the commercialization of SSE decreases delivered gas prices in Transco Zone 4 and Zone 5 South while serving increased demand from new generation. Average delivered prices in Zone 4 and Zone 5 South are forecast to decrease by \$0.03/MMBtu and \$0.06/MMBtu, respectively, between 2028-2031. The study area is served by increased southbound flows from Station 165 enabled by SSE, replacing much of the northbound gas through Station 85. Price effects are limited due to the addition of gas-fired generation that performs as a baseload resource in the SSE case.

Section 4: SSE Will Reduce Power Sector Emissions by Substitution of Natural Gas for Coal and Oil

In Section 4, LAI reports the results of the electric system dispatch modeling that shows how gas transported by SSE will ultimately be used. LAI has quantified the resulting displacement of other fossil fuel generation and natural gas transported by other pipelines to generators in the applicable SERC sub-regions. The simulation modeling presented in Section 4 to derive emission impacts is linked to the GPCM modeling of price impacts presented in Section 3. To compute emission impacts, LAI used Aurora, an electric system dispatch model, to model the impact of SSE on fuel use in the power sector. LAI concluded that SSE capacity will allow Duke and Georgia Power, the large power generation shippers, to construct fuel-secure combined-cycle units consistent with their Integrated Resource Plans (IRPs). The increased pipeline deliverability attributable to SSE will lessen constraints that limit the utilization of gas-fired generators in the study region. SSE will also help Duke retire some coal assets and reduce the region's need for coal dispatch when gas supplies would otherwise be constrained absent the addition of new pipeline delivery capability.

LAI has estimated reasonably foreseeable direct and indirect net GHG emissions attributable to SSE, accounting for the net reduction in GHG emissions from the displacement of other fuels, notably coal, but also including oil and natural gas delivered by other pipelines. For direct emissions, LAI relied on the estimated net GHG emissions from SSE's construction and operation as reported by Transco in its Resource Reports. LAI's estimate of reasonably foreseeable indirect net GHG emissions reflects downstream power sector emissions and downstream emissions from increased natural gas use by residential, commercial and industrial customers which have been developed via iteration of GPCM. Overall, reductions in indirect power sector emissions far outweigh increases in direct emissions from construction and operations as well as indirect emissions from increased RCI consumption. The SSE project, along with the efficient generation that it enables, provides annual emissions reductions of 7.2 million short tons of CO₂, 22.1 thousand short tons of NO_x, and 9.7 thousand short tons of SO₂ on average across 2028-2031. LAI also projected that electric power production cost savings from 2028-2031 would average about \$466 million with SSE relative to a No SSE case.

Key Conclusions

LAI has reached primary conclusions for each Section:

1. Rapid economic growth expected in the Carolinas and Georgia drives growing electricity demand in Duke and Georgia Power's service territories. Both Duke and Georgia Power need new fuel secure gas generation plants to keep pace with robust demand growth.
2. LAI's review of various pipeline operating patterns and pricing data sources show that pipelines that deliver gas to the shippers are highly utilized. Frequent restrictive congestion patterns observed in 2024 demonstrate the need for new pipeline infrastructure. Other gas and non-gas alternatives may be able to serve a portion of both Duke's and Georgia Power's incremental demand requirements, but do not represent a

cost-effective and reliable solution to the challenge of expanding existing infrastructure to serve anticipated demand growth.

3. GPCM gas transportation modeling shows that the SSE project meets increasing gas demand while lowering delivered gas prices in the study region. The project enables more southbound gas to serve the study region, replacing much of the south-to-north flows from upstream of Transco Station 85.
4. Aurora production cost modeling shows that the SSE project reduces GHG emissions by allowing for more natural gas generation to replace coal generation, which also results in substantial generation supply cost savings for electric ratepayers. This reduction in emissions far exceeds the emissions created by constructing and operating the SSE facilities.

1 Economic Growth is Driving Rapid Growth in Electricity Demand in the Carolinas and Georgia

In this Section, LAI reviews the drivers of the rapid economic and electric load growth expected in the study region over the forecast period. As discussed in Section 4.1, below, between 2023 and 2031, Duke forecasts that its winter peak demand will grow at an annual rate of 2.1% per year. Georgia Power’s winter peak is forecasted to grow at 5.5% per year. This load growth is driven by both broad economic growth and new large load customers. Broad economic growth drives steady load growth as new buildings are constructed and income growth leads to increases in existing customers’ demand. The rapid load growth forecast for the study region is primarily due to increasing load from large load customers associated with major new commercial and industrial projects, particularly manufacturing and data centers located in SSE shippers’ territories.

This Section begins with a discussion of the rapid economic development and investments in manufacturing and data centers forecast for Georgia and the Carolinas, and the slower economic and load growth expected in Mississippi and Alabama. As discussed in Section 1.2, the concentration of investment and economic growth in Georgia and the Carolinas reflects the favorable regulatory environment, tax policies and other factors that have made these states so attractive for new and expanding businesses. Sections 1.3 and 1.4 provide in depth discussions of the data center and manufacturing growth forecasted in Georgia and the Carolinas. This Section then provides a discussion of how the region’s recent economic development contributes to these forecasts, before concluding with a discussion of the role of state policy in the development of electric resources in the region.

1.1 Economic Development and New Large Customer Load in Georgia and the Carolinas

As discussed below, the increasing size and growing number of large projects planned for the study region has led both Duke and Georgia Power to adapt their load forecasting processes to account for new large loads:

- Duke’s “Economic Development teams and Large Account Management teams continually devote resources toward tracking and engaging with a series of potential development projects ... ones that were of large magnitude, (the largest often are referred to as ‘mega-projects’) and with plans sufficiently advanced such that the demand could be anticipated with a high degree of certainty ... were used to adjust the load forecast beyond what would have occurred only based on the calculations from the economic and other independent predictors.”¹
- Georgia Power also makes “an external adjustment to its baseline forecast to account for the increased large load additions described herein. An external adjustment is needed for these loads since Georgia’s unprecedented economic development growth would not otherwise be captured in the historical trends underlying the baseline forecast. ... As a result, Georgia Power has had to develop a way to estimate

¹ Duke 2023 IRP Appendix D Electric Load Forecast, p. 14.

the impacts of these projects on its system, while also addressing the inherent uncertainties around whether such projects will ultimately locate in Georgia, select Georgia Power as the electric service provider, and come online.”²

Georgia Power projects extraordinary customer load growth stemming from the rapid economic development taking place in the state.³ Since the pandemic, economic development in Georgia has proceeded at a record pace with an average of almost \$20 billion in investment commitments and 25,000 job commitments per year, as shown in Table 1, below. For example, in early 2025, Amazon announced plans to invest \$11 billion and create 550 new jobs to expand infrastructure in Georgia supporting cloud computing and AI technologies. Also in early 2025, the Department of Energy announced the closing of a \$6.57 billion loan to Rivian New Horizon to finance the development and construction of an EV manufacturing facility in Stanton Springs North. This facility is expected to support 2,000 construction jobs and 7,500 operations jobs. In 2023, Hyundai Motor Group and LG Energy Solution announced that they will invest \$2 billion to expand their battery cell manufacturing joint venture in Bryan County, creating 400 new jobs.⁴

Table 1: Georgia Economic Development Commitments: 2021-2024⁵

Fiscal Year ending June 30	Investments in New and Expanded Facilities	Jobs
2021	\$11.0 Billion	33,349
2022	\$21.2 Billion	51,132
2023	\$24.0 Billion	38,400
2024	\$21.2 Billion	26,900

Duke projects significant customer load growth stemming from the rapid economic development taking place in North Carolina.⁶ Since the pandemic, economic development in North Carolina has proceeded at a record pace with an average of over \$11 billion in investment commitments and 22,000 job commitments per year. Amazon plans to invest \$10 billion to expand its AI infrastructure, creating at least 500 new high-skilled jobs. Novo Nordisk, which makes the drugs Ozempic and Wegovy, is investing \$4.1 billion and adding 1,000 new jobs to construct a second plant at its Clayton campus. Johnson & Johnson is investing more than \$2 billion to build a state-of-the-art biologics manufacturing facility in Wilson, which will create 420 jobs. Natron Energy, which makes sodium-ion batteries, is building a \$1.4 billion gigafactory in Edgecomb County, which will create 1,062 new jobs. Amgen is building a new \$1 billion biomanufacturing facility in Holly Springs, which will create 370 new jobs. American Titanium Metal is investing \$896 million and adding 304 new jobs to expand its current operations in Fayetteville.

² Georgia Power Company Budget 2025 Load and Energy Forecast, section 1 – p. 3.

³ Georgia Power 2023 IRP Update Load and Energy Forecast, p. 16.

⁴ See Appendix A Subsection A for references.

⁵ See Appendix A Subsection B for references.

⁶ Duke IRP, Page 8.

Table 2: North Carolina Economic Development Commitments: 2021-2024⁷

Year	Investment	Jobs
2021	\$10.0 Billion	23,748
2022	\$15.6 Billion	27,144
2023	\$4.9 Billion	10,855
2024	\$16.1 Billion	17,586

Duke also projects strong customer load growth stemming from the rapid economic development taking place in South Carolina.⁸ Since the pandemic, economic development in South Carolina has proceeded at a record pace with an average of almost \$9 billion in investment commitments and 12,000 job commitments per year. Scout Motors, an automotive startup backed by Volkswagen, plans to build a new \$2 billion factory in Blythewood that will create 4,000 jobs. AESC, a global leader in the development and manufacturing of batteries, plans to build a \$810 million gigafactory in Florence that will supply next-generation cells for BMW starting in 2026 and create 1,170 jobs. Redwood Materials, a company that recycles, refines, and remanufactures battery materials, plans to locate a \$3.5 billion campus in the Charleston region and create 1,500 jobs. Volvo (\$500 million investment and 2,500 jobs), Mercedes-Benz (\$500 million investment and 1,300 jobs), and BMW (\$1.7 billion investment and 300 jobs) are also planning new facilities in South Carolina.

Table 3: South Carolina Economic Development Commitments: 2021-2024⁹

Year	Investment	Jobs
2021	\$5.7 Billion	18,000
2022	\$10.3 Billion	14,083
2023	\$9.2 Billion	14,120
2024	\$8.2 Billion	5,500

1.2 The Southeast Is Attractive for Economic Development

The rapid economic development in Georgia and the Carolinas are due to the favorable business environments created by the states' workforces, tax policies, logistics and infrastructure, regulatory policies and quality of life. Developers of new manufacturing and data center facilities are somewhat flexible in where the projects will be sited. Hence, information on relative rankings of business competitiveness provides a guide as to the outlook for growth of these industries in the Southeast states included in our study. Several information companies provide periodic surveys and other data to score and rank business conditions and competitiveness by state or locality in the US.

⁷ See Appendix A Subsection C for references.

⁸ Duke IRP, Page 8.

⁹ See Appendix A Subsection D for references.

CNBC Data-based Scores

CNBC provides annual scores and ranks of business conditions by state based on an evaluation of metrics in 10 broad categories. CNBC uses the same broad categories every year, but the weights and metrics used to evaluate each category have changed over time based on their importance in the site selection process.¹⁰ In descending order of importance for 2024, the categories were: Infrastructure, Workforce, Economy, Quality of Life, Cost of Doing Business, Technology & Innovation, Business Friendliness, Education, Access to Capital, and Cost of Living. CNBC's 2024 evaluation used a total of 128 metrics. The metrics are combined with weights based on how frequently the metric is included as a sales point in state economic development office marketing materials.¹¹

The overall ranks for each state in the study region for the past ten years are presented in Table 4. Georgia and North Carolina have been among the top ten states in each of the nine years scored, with North Carolina ranked first or second in each of the last four years, while Mississippi has consistently scored near the bottom. Alabama and South Carolina have improved in recent years, and in 2024 both states were above average for the first time in the last decade.

Table 4: Overall Business Competitiveness Rank by State

	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015
North Carolina	2	1	1	2	N/A	3	9	5	5	9
South Carolina	19	27	36	39	N/A	34	30	29	27	29
Georgia	4	4	10	6	N/A	6	7	2	8	5
Alabama	20	42	33	31	N/A	37	41	37	38	41
Mississippi	49	48	50	45	N/A	48	49	48	47	43

Source: CNBC annual evaluation, published in a mid-July issue except for June publication in 2015. Study was not conducted during the peak COVID year, 2020

North Carolina's Ports of Wilmington and Morehead City support container and bulk shipping, respectively. Its two deep water ports have fast turn times and capacity to support more than four million tons of general cargo annually. The container terminal at the Port of Wilmington ranked as the most productive port in North America in 2022. An inland port in Charlotte is at the heart of the Southeast's manufacturing and distribution sites. The state also has 10 airports that service over 250 destinations (45 of which are international), including the world's 7th busiest (Charlotte Douglas Airport). North Carolina's over 3,000 miles of freight railroad, 2,250 miles of Class 1 Railroad and five intermodal terminals connect North Carolina's ports, airports, and businesses.¹²

¹⁰ CNBC Top States for Business Methodology, July 11, 2024, <https://www.cnbc.com/2024/06/13/how-we-are-choosing-americas-top-states-for-business-2024.html>.

¹¹ Scott Cohn, "These 10 U.S. states have America's best economies in 2024", Jul 18, 2024. <https://www.cnbc.com/2024/07/18/americas-10-best-state-economies.html>

¹² <https://edpnc.com/why-nc/infrastructure/>

Georgia benefits from the Hartsfield-Jackson International Airport, the busiest airport in the world; the Port of Savannah, the single largest and fastest-growing container terminal in the country; the Port of Brunswick, one of the most utilized port terminals in the country for roll-on, roll-off cargo; and a robust network of top-ranked highways and accessible railways. Agribusiness is enabled by the state’s ample cold storage capacity, and speed-to-market and workforce solutions like the Georgia Ready for Accelerated Development certification and Georgia Quick Start programs are spurring growth in advanced manufacturing investments since FY2022.¹³

Site Selection Magazine Survey Rankings

Site selectors are focused on competitive advantages for building, expanding, or redeveloping facilities. As scouts for where to locate new facilities, their preferences may be better indicators of new siting decisions than a scoring system or survey that encompasses both existing and expanding or new business operations. In *Site Selection Magazine’s* most recent annual survey of siting professionals, Georgia, North Carolina and South Carolina were first, second and third in their “business climate” ranking.¹⁴ Georgia’s and North Carolina’s attractiveness to site selectors reflects their overall competitiveness, while South Carolina received the most votes for the state with the best manufacturing workforce.

Table 5: Site Selection State Business Climate Ranking

- 1. Georgia**
- 2. North Carolina**
- 3. South Carolina**
4. Tennessee and Texas (Tied)
6. Virginia
- 7. Alabama, Mississippi, and Ohio (Tied)**
10. Indiana

Business Facilities Magazine

A few of the key measures from the *Business Facilities* magazine staff’s 2024 state rankings for businesses planning relocation or expansion projects are summarized here.¹⁵ In the broad “best business climate” ranking, three of the five states in our study region (notably, the states that drive power supply needs for the shippers) made the top 10 list in 2024:

¹³ Georgia USA, “ Georgia Breaks Economic Development Records for Third Year in a Row,” August 2, 2023. <https://georgia.org/press-release/georgia-breaks-economic-development-records-third-year-row>

¹⁴ Ron Starner, “Site Selectors Survey: Why Site Selectors Love the South,” *Site Selection Magazine*, January 2025. [Site Selectors Survey: Why Site Selectors Love the South - Site Selection Magazine](https://www.site-selection.com/news/2025/01/01/site-selectors-survey-why-site-selectors-love-the-south)

¹⁵ Business Facilities Staff, “Business Facilities’ 20th Annual Rankings Report,” *Business Facilities*, August 8, 2024. <https://businessfacilities.com/20th-annual-rankings-report-2024-state-rankings/>

Table 6: Business Facilities Magazine 2024 State Business Climate Rankings

1. Texas
- 2. North Carolina**
3. Virginia
4. Florida
5. Tennessee
- 6. Georgia**
7. Indiana
8. Colorado
9. Arizona
- 10. South Carolina**

Georgia was also in the top ten for the Aerospace/Defense category (10th place). South Carolina was also in the top ten for the Automotive category (6th place). Georgia (1st place), North Carolina (3rd place) and South Carolina (6th place) were also in the top ten for the EV Investment category. North Carolina was also in the top ten for the Agribusiness category (9th place). Georgia was also in the top ten for the Film & Television (1st place) and Food Processing (8th place) categories. North Carolina was also in the top ten for the Life Sciences category (5th place). South Carolina (3rd place), North Carolina (5th place) and Georgia (10th place) were in the top ten for the fastest growing population category.

These CNBC, Site Selection Magazine and Business Facility Magazine rankings of states and local market areas are used by site selection consultants and businesses to assess where to locate new operations. Therefore, we would expect Georgia and the Carolinas to be highly ranked in attractiveness to new and expanding businesses given their recent success in securing investment and job commitments.

1.3 Rapid Growth Is Projected for Data Centers, and Associated Energy Demand

Between 2013 and 2023, U.S. electric demand grew slowly due to a combination of improvements in energy efficiency, moderate economic growth and limited penetration of EV and building electrification. Over the next decade, however, load growth is expected to accelerate as a result of growth in data centers, industrial output, EV adoption and building electrification. The growth of data centers is documented by substantial estimates in reported actual electric consumption and the many business, government, and academic research studies that project their future electric loads. For example, a June 2024 research report by Bank of America (BoA) indicates that BoA's 2024 forecast of 2.8% growth in U.S. electrical load from 2023 to 2030 is mostly due to these factors.¹⁶

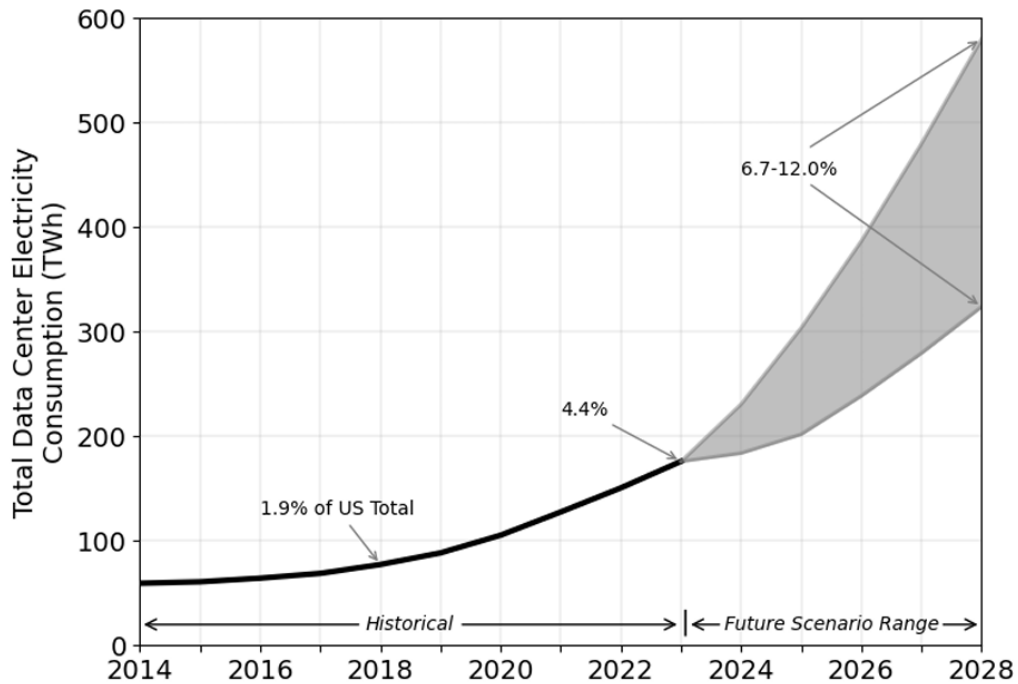
¹⁶ "Removing 'grid' lock 2.0: updated deep dive on US grid drivers," Bank of America Securities Global Research, June 3, 2024, [BoFA - Industrials/Multi-Industry](#)

Table 7: Sources of Incremental U.S. Electrical Load Growth, 2023 to 2030

	CAGR
Historical, 2013-2023	0.4%
Data centers	0.5%
Industrial growth	0.4%
EV adoption	0.5%
Building electrification	1.0%
Forecast, 2023-2030	2.8%

As discussed in Section 1.1, new and expanding large customers are driving load growth in the study region, especially, manufacturing and data centers. Until recently, data centers were mainly used for data storage, computing, and network connectivity. Over the last decade, the use cases for data centers have expanded to include machine learning; high-performance computing for genome sequencing, high-frequency trading, blockchain token (cryptocurrency and other encrypted data) mining; and other cloud-based or edge uses. The data center industry’s improving operational efficiency during this period limited the growth of U.S. computing-related energy while serving greater demand.

Figure 1: Annual U.S. Data Center Electricity Use¹⁷



¹⁷ Lawrence Berkeley National Laboratory, 2024 United States Data Center Energy Usage Report, December 2024, <https://eta-publications.lbl.gov/sites/default/files/2024-12/lbnl-2024-united-states-data-center-energy-usage-report.pdf>, p 5.

As shown in Figure 1, datacenter electricity use accelerated in 2018, and by 2023 its share of total U.S. electricity demand had more than doubled, growing from 1.9% to 4.4%. Since ChatGPT and similar AI technologies became available in 2022, demand for data center computing has continued to increase, and may accelerate further with the growth of highly electricity-intensive generative AI modeling applications.¹⁸

Cloud-based application data centers may be located in open-land rural areas to take advantage of lower land cost and less nearby competition for large electric loads. Individual business enterprises or telecommunication service providers may develop their own data centers, which may also be sited away from a hub of data centers. Edge application data centers, such as for ride-sharing mobile device apps, smart homes, autonomous vehicles, and other interactive use software products that rely on sensor data that benefit greatly from very brief latency are usually located close to major urban centers.¹⁹

Despite all the media and industry interest in the growth of AI applications since the 2022 release of ChatGPT, the workload of AI at data centers is forecast to grow significantly but remain a small portion of total data center power use through 2028, according to Schneider Electric.²⁰ The company's global data center electric use forecast projects that the AI share of data center power use will roughly double between 2023 (< 9%) and 2028 (> 17%). Electricity use by the GPU chips utilized by generative AI is much higher than for the CPU chips utilized by many other data center applications.

The number of data centers by state and market area in the study region as of early April 2025 is shown in Table 8. Currently, Georgia leads the five states with 129 data centers, followed by North Carolina with 82 data centers. The much smaller numbers of data centers in South Carolina, Alabama, and Mississippi are commensurate with their smaller populations and workforces with the requisite technical and professional skills. The number of data centers located in the Atlanta metro area has grown rapidly in recent years as a result of increasing electric power availability siting constraints in the larger Virginia data centers hub. The large number of North Carolina data centers, centered around Charlotte, has also been attributed, in part, to electric grid constraints and congestion on building more data centers in Virginia.²¹

¹⁸ *Id.*, pp. 70-71.

¹⁹ Lightbox, "A Growing Demand for Land: Site Selection for Data Centers," October 30, 2024. <https://www.lightboxre.com/insight/a-growing-demand-for-land-site-selection-for-data-centers/>

²⁰ Schneider Electric, "The AI Disruption: Challenges and Guidance for Data Center Design," White Paper 110, Version 2.1, December 6, 2023. https://www.se.com/us/en/download/document/SPD_WP110_EN/

²¹ CBRE, "North America Data Center Trends H2 2022," February 17, 2023. <https://www.cbre.ca/insights/reports/north-america-data-center-trends-h2-2022>

Table 8: Number of Data Centers by State and Market Area, April 2025

North Carolina		South Carolina		Georgia		Alabama		Mississippi	
Market	Data Centers	Market	Data Centers	Market	Data Centers	Market	Data Centers	Market	Data Centers
Charlotte	36	Charleston	15	Atlanta	120	Huntsville	9	Jackson	3
Raleigh	12	Columbia	4	Alpharetta	3	Birmingham	6	Hattiesburg	1
Hickory	8	Greenville	3	Columbus	2	Bridgeport	4	Meridian	1
Maiden	8	Rock Hill	2	Buford	1	Mobile	3	Starkville	1
Greensboro	5	Aiken	1	Carrollton	1	Auburn	2		
Asheville	2	Myrtle Beach	1	Dalton	1	Montgomery	2		
Durham	2	Seneca	1	Statesboro	1				
Winston Salem	2	Spartanburg	1						
Catawba	1								
Fayetteville	1								
Goldsboro	1								
Marble	1								
Mooresville	1								
Roxboro	1								
Sylva	1								
Total	82	Total	28	Total	129	Total	26	Total	6

Source: Compiled from data in DataCenterMap.com, accessed April 4, 2025.

A May 2024 Electric Power Research Institute (EPRI) report indicated that electricity consumption by Meta, Amazon, Microsoft, and Google, the main cloud computing and digital services providers in the US, more than doubled between 2017 and 2021.²² AI model electricity use is about 10x as electricity-intensive per query as traditional Google queries. An AI model comparison over time in the EPRI report indicated that ChatGPT-3 in 2021 needed about 34 training days and used 1,287 MWh of energy. The larger and more complex ChatGPT-4 in 2023 needed about 100 training days and vastly increased its energy use to 62,318.8 MWh.²³ EPRI projected under three growth scenarios that data center electricity use would consume between 4.6% to 9.1% of U.S. electricity generation by 2030. At the local level near a hub of data centers, their combined electric use can be a very large share of total consumption. EPRI reported that in 2023 data centers in Virginia accounted for about one-fourth of the state’s electric load. Table 9 shows the EPRI report’s 2023 electric load and projected 2030 load by the four Southeast states in our study region that were included in the EPRI’s examination of the 44 states with significant data center load in 2023.

²² EPRI, “Powering Intelligence - Analyzing AI and Data Center Energy Consumption,” EPRI Report 3002028905, May 2024.

²³ Ibid., p. 30, Table B1.

Table 9: 2023 Data Center Loads and Projections of Potential Consumption by State in 2030

	2023 Load		2030 Load Projections							
			Low-growth Scenario (3.71%)		Moderate-growth Scenario (5%)		High-growth Scenario (10%)		Higher-growth Scenario (15%)	
	Share of Total State Electricity Consumed	GWh/y	Share of Total State Electricity Consumed	GWh/y	Share of Total State Electricity Consumed	GWh/y	Share of Total State Electricity Consumed	GWh/y	Share of Total State Electricity Consumed	GWh/y
Alabama	1,489	1.71%	1,922	2.05%	2,095	2.23%	2,902	3.07%	3,954	4.13%
Georgia	6,175	4.26%	7,969	5.08%	8,689	5.51%	12,034	7.48%	16,397	9.92%
North Carolina	2,673	1.92%	3,449	2.30%	3,761	2.50%	5,208	3.44%	7,096	4.62%
South Carolina	2,024	2.45%	2,611	2.93%	2,847	3.18%	3,943	4.36%	5,373	5.84%

Source: EPRI, “Powering Intelligence - Analyzing AI and Data Center Energy Consumption,” May 2024, Appendix Table A1.

1.4 Domestic Manufacturing Growth is Also Driving Energy Demand

In recent years, much of the national increase in new manufacturing operations has been new or expanded facilities in the Southeast. Reshoring of operations and the enactment of the federal Inflation Reduction Act in August 2022 have been cited by many as reasons for a growing number of new and planned industrial facilities, particularly large and electricity-intensive operations.²⁴ Looking forward, import tariffs imposed under President Trump are designed to further strengthen the growth of domestic manufacturing nationwide, especially automobile manufacturing.²⁵

Table 10 indicates that 82, or over one-third, of the five-state region’s new manufacturing plant projects announced in 2024 are in North Carolina, 57 are in South Carolina, 49 are in Georgia, 26 are in Alabama, and six are in Mississippi. The operational start dates of these projects are within the next five years. This data, taken mainly from company press releases, is consistent with industrial sector economic development over the past five years. The number of new manufacturing plant project announcements in Georgia is roughly consistent with Georgia Power’s “Large Load Economic Development Report Q3 2024,” which indicates that three of five committed industrial customers with future loads of at least 45 MW have broken ground.²⁶

²⁴T. Bruce Tsuchida, Long Lam, Peter Fox-Penner, Akhilesh Ramakrishnan, Sylvia Tang, Adam Bigelow, and Ethan Snyder, “Electricity Demand Growth and Forecasting in a Time of Change,” The Brattle Group, May 2024. <https://www.brattle.com/wp-content/uploads/2024/05/Electricity-Demand-Growth-and-Forecasting-in-a-Time-of-Change-1.pdf>

²⁵ The White House, “Fact Sheet: President Donald J. Trump Adjusts Imports of Automobiles and Automobile Parts into the United States,” March 26, 2025. <https://www.whitehouse.gov/fact-sheets/2025/03/fact-sheet-president-donald-j-trump-adjusts-imports-of-automobiles-and-automobile-parts-into-the-united-states/>; The White House, “Fact Sheet: President Donald J. Trump Restores Section 232 Tariffs,” February 11, 2025. <https://www.whitehouse.gov/fact-sheets/2025/02/fact-sheet-president-donald-j-trump-restores-section-232-tariffs/>

²⁶ Georgia Power Company, Q3 2024 Large Load Economic Development Report. November 18, 2024. Docket No. 55378, Table 1.

Table 10: 2024 New Manufacturing Project Announcements Summary²⁷

State	Number of Projects
NC	82
SC	57
GA	49
AL	26
MS	6
Region	220

In South Carolina, Santee Cooper plans to add more than 1,000 MW of natural gas-fired electric generation to help meet expected industrial growth and continued economic development across the state. As of early 2024, Santee Cooper had 27 large load customers with industrial and other economic operations.²⁸

1.5 Economic Growth in the Southeast from 2014-2024

To assess economic growth and electric load growth projections in the study region, LAI studied the past record and expected future changes in the key drivers of economic growth and electric load growth. As for most states, the recent upward trends in electric load growth and their continuation for the next decade are the emergence of more and larger data centers and new or expanded manufacturing facilities. This look back sets the stage for the projection of economic and electric load growth in future years.

Table 11 shows total, or economy-wide, real GDP annual levels and growth rates by state, region, and nation over the most recent two five-year periods. The region’s compound annual growth rate (CAGR) has been slightly higher than the nation’s growth rate in each of the two most recent five-year periods. Within the region, Georgia had the highest CAGR (3.5%) and South Carolina second highest (2.9%) during the 2015 to 2019 period. Since then, North Carolina topped the five states during the 2020 to 2024 period with a 3.0% CAGR and South Carolina remained second highest with a 2.6% CAGR. While continuing to lose population, which restrains GDP growth, Mississippi’s CAGR values increased considerably in the more recent five-year period, nearing the growth rates of Alabama.²⁹

Over the past decade, real total gross domestic product (GDP) growth trajectories have been stable and consistent for all five states in the study region. Since 2015 the rank order of the size of state real GDP has been the same every year, with the GA economy slightly larger than NC, and SC slightly larger than AL, and MS the smallest. The GA GDP had the largest Covid pandemic-caused decline in 2020 from the prior year.

²⁷ See Appendix A Subsection E for references.

²⁸ Jodi Shafto “U.S. Southeast Manufacturing, Industrial Growth Driving Billions in New Natural Gas Infrastructure,” Natural Gas Intelligence, May 23, 2024. <https://www.naturalgasintel.com/news/us-southeast-manufacturing-industrial-growth-driving-billions-in-new-natural-gas-infrastructure/>

²⁹ “U.S. Census Bureau QuickFacts: Mississippi,” <https://www.census.gov/quickfacts/fact/table/MS/>

Table 11: Real Gross Domestic Product: All Industries by Area, 2014-2024

	AL	GA	MS	NC	SC	Region	Nation
Year	Annual Value (Billions of Chained 2017 \$)						
2014	206.1	517.5	109.3	509.8	206.1	1,548.7	18,261.7
2019	225.3	620.7	111.2	568.0	239.0	1,764.2	20,715.7
2024	252.7	701.1	122.4	661.9	273.3	2,011.4	23,305.0
Years	Compound Annual Growth Rate						
2015-2019	1.8%	3.7%	0.3%	2.2%	3.0%	2.6%	2.6%
2020-2024	2.3%	2.5%	1.9%	3.1%	2.7%	2.7%	2.4%
2015-2024	2.1%	3.1%	1.1%	2.6%	2.9%	2.6%	2.5%

Source: U.S. Bureau of Economic Analysis.

Table 12 below shows manufacturing sector real GDP annual levels and growth rates by state, region, and nation over the most recent two five-year periods. In the more recent five-year period, 2020 to 2024, the region’s manufacturing CAGR caught up with the national average CAGR. Over the 2015 to 2024 decade, Alabama and Georgia led the region’s manufacturing sector growth with 2.2% CAGR. In the more recent five-year period, Georgia’s manufacturing growth rate was higher than previously, while Alabama’s growth rate between periods has been constant. North Carolina manufacturing growth increased from negative to no-growth from the earlier to the more recent five-year period. Despite losing population, Mississippi managed to have zero manufacturing growth in the 2015 to 2019 period and grow manufacturing sector GDP during the 2020 to 2024 period.

Table 12: Real Gross Domestic Product: Manufacturing by Area, 2014-2024

	AL	GA	MS	NC	SC	Region	Nation
Year	Annual Value (Billions of Chained 2017 \$)						
2014	33.8	54.4	16.1	93.0	32.1	229.5	2,049.2
2019	37.4	60.0	16.3	87.2	36.4	237.3	2,224.8
2024	41.9	69.2	18.2	87.6	37.5	254.4	2,382.7
Years	Compound Annual Growth Rate						
2015-2019	2.1%	2.0%	0.2%	-1.3%	2.5%	0.7%	1.7%
2020-2024	2.3%	2.9%	2.3%	0.1%	0.6%	1.4%	1.4%
2015-2024	2.2%	2.4%	1.2%	-0.6%	1.6%	1.0%	1.5%

Source: U.S. Bureau of Economic Analysis.

After the emergence of the internet in the 1990s, data centers have grown in number and individual facility size of operations. As a result, the data services sector, which also includes business services apart from data centers, has grown steadily as a share of total U.S. GDP. With the introduction of huge databases and AI models that “train” data to provide information, the AI segment of the data services sector of the domestic economy has grown rapidly in the period after 2019, nearly doubling in real GDP from 2019 to 2023.

The Bureau of Economic Analysis uses the North American Industry Classification System (NAICS) code 518210, “computing infrastructure providers, data processing, web hosting, and related services” for the GDP industry sector shown. NAICS 518210 is a broad category of information services that encompasses block chain data mining and artificial intelligence data centers but does not explicitly mention those growing segments of use at data centers.

From 2015 to 2023, the data services industry more than tripled in real GDP in both the U.S. and the study region, as shown in Table 13 below. However, the region’s share of the industry in the U.S. has trended downward from 5.25% in 2014 to 4.60% in 2023. Since 2019, Georgia has produced over half of the region’s GDP in data services. Both Georgia and Alabama had higher rates of GDP growth in data services than the U.S. from 2015 to 2023. North Carolina experienced almost no growth in data services GDP from 2015 to 2019, while Mississippi had a slightly negative CAGR during those years. During the four-year period from 2020 to 2023, all states in the region except North Carolina substantially exceeded the U.S. growth rate, and North Carolina had only a slightly lower growth rate than the U.S. These results, which show generally faster GDP growth in data services by the states in the region relative to the US, are not surprising insofar as these states began the 10-year historical period with a relatively small 5.25% share of total U.S. data services, compared to 8.48% share for all industries and 11.20% for manufacturing.³⁰

Table 13: Real Gross Domestic Product: Data Processing, Hosting, & Other Information Services, 2015-2023

	AL	GA	MS	NC	SC	Region	Nation
Year	Annual Value (Billions of Chained 2017 \$)						
2014	0.3	3.4	0.2	3.6	0.7	8.2	155.6
2019	0.5	6.8	0.2	3.7	1.0	12.2	288.7
2023	1.4	14.1	0.3	6.8	2.1	24.7	536.4
Years	Compound Annual Growth Rate						
2015-2019	11.3%	14.9%	-3.3%	0.7%	8.7%	8.4%	13.2%
2020-2023	28.5%	19.9%	18.0%	16.3%	19.7%	19.2%	16.8%
2015-2023	18.6%	17.1%	5.7%	7.3%	13.5%	13.1%	14.7%

Source: U.S. Bureau of Economic Analysis. Since 2024 data are not yet available for this series, 2023 data are shown instead.

1.6 State Governments in the Southeast Support Gas-Fired Capacity Additions to Meet Load Growth

Per FERC, “Utilities in the Southeast are vertically integrated and virtually all the physical sales in the Southeast are done bilaterally.”³¹ Like most vertically integrated U.S. utilities, Duke and Georgia Power are regulated by state utility commissions which require that they submit IRPs

³⁰ See Table 12 for manufacturing GDP data and Table 11 for GDP data in all industries.

³¹ Federal Energy Regulatory Commission, Market Assessments: Electric Power Markets, accessed February 12, 2025. <https://www.ferc.gov/electric-power-markets>

which provide long-term forecasts of electricity demand and identify potential portfolios of supply resources that can meet this demand. IRPs are subject to review by state regulators and reflect state and federal legislation and regulations. In addition, vertically integrated utilities also must seek approval from state regulators before building or contracting new resources. As discussed in Sections 2.1 and 4.1, the load forecasts and IRPs that form the basis for LAI's electric forecasting have been approved by the relevant state utility commissions. Utilities seek to balance various attributes such as reliability, environmental impacts, affordability, and safety in their assessments.

Sections 2.1 and 4.1 contain detailed analysis and discussion of load growth in the study region. It is important to note that Duke and Georgia Power's forecast load growth over the study period reflect input from large load customers who have committed to taking electric service and potential customers with announced plans to expand in Georgia and the Carolinas. As explained in Duke's Supplemental Planning Analysis, Duke's updated load forecast reflects how the Carolinas'

continued efforts to attract jobs and grow the states' economies ... have produced truly unprecedented economic development growth ... numerous prospective customers that have been exploring locating or expanding their operations in the Companies' service territory have made new announcements and material commitments to take electric service from the Companies, such that the Companies must now include their load demand in the Companies' updated load forecast.³²

Similarly, Georgia Power's 2025 IRP discusses how it uses information on "the numerous new large load projects Georgia Power has been selected to serve as well as a considerable pipeline of potential future projects" and "accounts for uncertainties related to new large load projects, including state selection, electric provider selection, project delays, and the materialization of load. Georgia Power conducted hundreds of thousands of simulations using different combinations of these uncertainties to produce probability distributions that were then utilized to develop the external adjustments."³³

Out of the states in the study region, only North Carolina has statutory greenhouse gas emissions and clean energy targets. House Bill 951, which was ratified in 2021, states that "The Utilities Commission shall take all reasonable steps to achieve a seventy percent (70%) reduction in emissions of carbon dioxide (CO₂) emitted in the State from electric generating facilities owned or operated by electric public utilities from 2005 levels by the year 2030 and carbon neutrality by the year 2050."³⁴ Under the statute, the North Carolina Utilities Commission (NCUC) will develop a Carbon Plan in concert with electric utilities. This Carbon Plan has effectively been merged with the existing IRP process. Notably, there are several aspects of the bill that give the NCUC wide discretion in terms of how goals are met. NCUC must "... ensure any generation and resource changes maintain or improve upon the adequacy and reliability of the existing grid" and "... retain

³² Duke Supplemental Planning Analysis, p. 3.

³³ Georgia Power 2025 IRP, pp. 35 and 37.

³⁴ General Assembly of North Carolina Session 2021, House Bill 951, see part I.
<https://www.ncleg.gov/Sessions/2021/Bills/House/PDF/H951>

discretion to determine optimal timing and generation and resource-mix to achieve the least cost path to compliance with the authorized carbon reduction goals, including discretion in achieving the authorized carbon reduction goals by the dates specified...”³⁵ The status essentially codifies decarbonization goals into the utility planning process, but NCUC remains the decision maker for state policy.

The other states in the study region do not have greenhouse gas emissions targets or clean energy standards codified in legislation.³⁶ However, the shippers’ corporate parents have set emissions goals. Duke Energy is targeting a 50% reduction in GHG emissions by 2030 and net zero by 2050.³⁷ The Southern Company has similar corporate goals.³⁸ These goals are taken into account in the IRP development process. Additional detail about the shippers’ IRPs is given in the following section.

³⁵ *Id.*, see I(3) and I(4).

³⁶ Center for Climate and Energy Solutions, State Climate Policy Maps.
<https://www.c2es.org/content/state-climate-policy/>

³⁷ Duke Energy: Our Company: Climate Change. Accessed February 12, 2025.
<https://www.duke-energy.com/our-company/environment/global-climate-change>

³⁸ Southern Company: Net Zero Transition. Accessed February 12, 2025.
<https://www.southerncompany.com/sustainability/clean-energy/net-zero-transition.html>

2 Existing Pipeline Capacity Cannot Meet Shippers’ Needs for New and Existing Power Generation

LAI conducted an independent assessment of the pipeline capacity available to the shippers that have entered into precedent agreements for SSE, with a focus on Duke and Southern Company Services. As shown in Table 14, Duke and Southern Company Services account for 1,400 MDth/d or 88% of SSE capacity. Other power generators account for 80 MDth/d, or 5% of total SSE capacity. Local Distribution Companies (LDCs) account for the remaining 7%.

Table 14: SSE Customers and Subscribed Capacity³⁹

Shipper	Transportation Contract Quantity (Dth/d)	End Use
Duke	1,000,000	Power Generation
Southern Company Services	400,000	Power Generation
South Carolina Public Service Authority	80,000	Power Generation
Atlanta Gas Light Company	75,000	Local Distribution
Patriots Energy Group	14,000	Local Distribution
Greer Commission of Public Works	10,000	Local Distribution
Fountain Inn	2,400	Local Distribution
Municipal Gas Authority of Georgia	2,000	Local Distribution
City of Wilson, NC	2,000	Local Distribution
City of Danville, VA	1,500	Local Distribution
Fort Hill Natural Gas Authority	5,000	Local Distribution
Southwest Virginia Natural Gas	5,000	Local Distribution
Total	1,596,900	

In this Section, LAI reviews shippers’ needs for gas capacity and available alternatives to the SSE project and assesses the feasibility and costs of these alternatives. Duke and Southern Company Services needs are considered in the context of the relevant utility IRPs, and planning for new gas-fired generation expansion needed to accommodate the load growth discussed in Section 1. This is followed by a discussion of how neighboring utilities’ plans for gas-fired generation also will increase demand for transportation rights on pipeline infrastructure. LAI then surveys the current use of pipeline infrastructure via a review of firm transportation entitlement holdings, scheduled flows data, critical notices, and spot pricing dynamics. Finally, LAI identifies the limited project alternatives to the SSE project. Regarding the interstate natural gas system, the study region reflected the segments of Transco that will see increases in FT capability via SSE, from Station 85 near the Mississippi-Louisiana border to Station 165 near the Virginia-North Carolina border. SNG pipeline also delivers natural gas into the study region from the Gulf. For purposes of gas system review, the area of interest is downstream of the Enterprise and Reform

³⁹ Southeast Supply Enhancement Project Resource Report No. 1 General Project Description, p. 1-4. FERC Docket: CP25-10-000, Filed on October 29, 2024.

compressor stations. The Elba Express and Carolina Gas pipeline systems are also part of the study region.

In this review, LAI found:

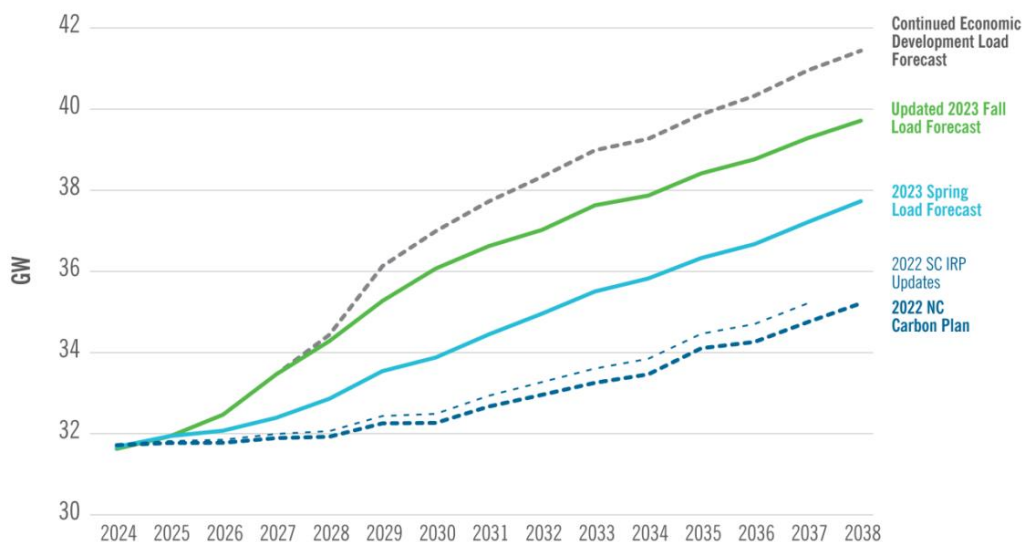
- Duke Energy has plans for more than 4 GW of combined-cycle capacity directly linked to the SSE and other new pipeline expansions. Duke expects that three new combined-cycle units will require 705 MDth/d, compared to the 1,000 MDth/d of firm transportation that they have subscribed for on SSE.
- Georgia Power, which receives gas from Southern Company Services, has authorized an All-Source Request for Proposals (RFP) to meet capacity needs from 2029 to 2031. IRP modeling that supported that conclusion included about 4 GW of gas-fired capacity additions by 2031.
- Other utilities in the study region expect to add about 4 GW of gas-fired capacity by 2031.
- A review of firm entitlements shows that there is little or no unsubscribed firm capacity into the portions of Transco Zones 4 and 5 that SSE targets for delivery. Utilization of the SNG system, which also supplies power generators in the market area, is also high.
- Pipeline utilization, both north to south and south to north, into the relevant parts of the Transco system, is high. Receipts from the Mountain Valley Pipeline (MVP) into Transco at the Cherrystone interconnect are replacing north to south flows on the Transco main line due to bottlenecks near Station 165 that the SSE project will alleviate.
- The high volume and increasing frequency of Operational Flow Orders (OFOs) in Zones 4 and 5 implies constraints on Transco's system in the Southeast.
- Average delivered gas prices are significantly cheaper during summer and shoulder months at the source of SSE (Transco Station 165) than at SSE's delivery locations (Transco Zones 4 or 5 South).
- LAI considered three categories of potential project alternatives: energy conservation, alternative sources of natural gas and alternative fuels. Limited utilization means that LNG cannot substitute for the SSE, while expansion of other pipelines serving the region will not provide service to the Carolinas. Shippers' resource planning demonstrates that energy conservation and alternative fuels are insufficient to ensure long-run reliability.

Given these findings, SSE is necessary for shippers to meet their gas supply needs and other project alternatives cannot meet these needs in a similar way.

2.1 Power Generation Shippers Plan on Using New Gas-fired Generation to Meet Growing Electricity Demand in NC, SC and GA

Duke’s winter peak is expected to grow from 31.6 GW in 2024 to 36.6 GW in 2031 and 39.7 GW in 2038, per the Carolinas Resource Plan Supplemental Planning Analysis.⁴⁰

Figure 2: Duke Carolinas Winter Peak Forecast⁴¹



As shown in Figure 2, Duke’s load forecast has been revised upward over the last few years as the Carolinas’ economy recovered from the pandemic and new large load customers have committed to the region. Duke’s 2022 Carbon Plan filings rely on economic forecasts from early 2022. Duke subsequently produced the 2023 Spring Load Forecast and Updated 2023 Fall Load Forecast in response to an accelerating number of economic development projects making commitments to the Carolinas.⁴² In Fall 2023, Duke also prepared the Continued Economic Development Load Forecast which took into account expected load growth from known “mega projects” that have not yet made material commitments.⁴³ As part of the proposed resource expansions to meet load growth, Duke proposes to add 6.2 GW of gas-fired capacity by 2031 and 8.9 GW of gas-fired capacity by 2035.^{44, 45} The quantitative modeling discussed later in this report utilized the load and supply inputs assumed in the Fall 2023 Supplemental Planning Analysis.

⁴⁰ Duke Energy Carolinas and Duke Energy Progress, Supplemental Planning Analysis for 2023 Carolinas Resource Plan, pages 19-20, 23. Docket E-100 Sub 190, filed January 31, 2024.

<https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/supplements/supplemental-planning-analysis.pdf>

⁴¹ *Id.*, page 5.

⁴² *Id.*, page 15.

⁴³ *Id.*, page 22.

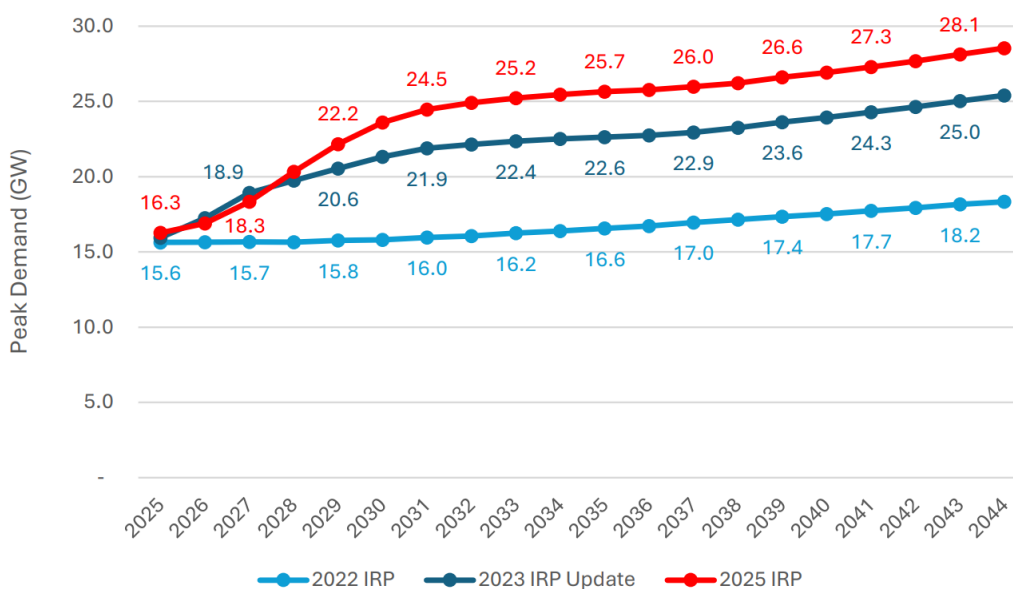
⁴⁴ *Id.*, page 47-48.

⁴⁵ Duke is planning to file an updated Carolinas Resource Plan in the fall of 2025. Duke Energy, Carolinas Resource Plan, accessed February 20, 2025.

<https://www.duke-energy.com/our-company/about-us/irp-carolinas>

Likewise, Figure 3 illustrates how Georgia Power has repeatedly updated its load forecast and now projects to have winter peak grow from 16.3 GW in 2025 to 24.5 GW in 2031 and 28.1 GW in 2043 per the 2025 IRP.⁴⁶ In its 2025 IRP, Georgia Power proposed to defer existing gas and coal power plant retirements, upgrade gas and nuclear units, and preserve hydro units to meet capacity supply needs, in addition to conducting the 2029/2031 All-Source RFP that was approved as part of the 2022 IRP. All the proposed investment in the existing fleet accounted for about 1,590 MW. Georgia Power has also proposed to issue an additional All-Source RFP in Q3 2025 for 2032 and 2033 capacity needs. The target MW quantities for this subsequent RFP will be informed by the results of the 2029/2031 All-Source RFP. Georgia Power also aims to add up to 4,000 MW of incremental renewable resources by 2035.⁴⁷ The 2025 IRP was recently filed and therefore has not been approved by the Georgia Public Service Commission (GA PSC). The quantitative modeling discussed later in this report utilized load and supply inputs from the 2023 IRP Update for the base case, as this IRP has been approved by the GA PSC. The load and supply inputs from the 2025 IRP are considered in a sensitivity case.

Figure 3: Georgia Power Projected Peak Winter Demand⁴⁸



In its 2023 IRP Georgia Power proposed additional measures, aside from the 2029/2031 All-Source RFP approved as part of the 2022 IRP, which would be needed to meet a capacity deficit that would grow to as much as 19.2 GW.⁴⁹ The All-Source RFP notes that “GPC estimates that up

⁴⁶ Georgia Power 2025 Integrated Resource Plan, filed January 31, 2025 in Georgia Public Service Commission Docket No. 56002, page 35.

<https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/2025-Integrated-Resource-Plan.pdf>

⁴⁷ *Id.*, page 3

⁴⁸ *Id.*

⁴⁹ Georgia Power 2023 Integrated Resource Plan Update, filed October 2023 in Georgia Public Service Commission Docket No. 55378, pages 10-11.

to 8,500 MW of Capacity Resources are necessary to satisfy GPC's capacity needs... This estimate is based on expiration of capacity power purchase agreements, potential retirement of certain GPC generation units, and projected load growth."⁵⁰ Georgia Power further estimated capacity needs growing from 2,280 MW in the 2028/2029 winter to 5,960 MW in the 2030/2031 winter.⁵¹

For both shippers, new gas-fired generation will reduce reliance on aging coal units. Further discussion of each utility's gas resource expansions, which SSE will in part supply, are below.

Duke Carolinas

Duke's 2023 Supplemental Planning Analysis included five 1,360 MW combined-cycle (CC) units that would provide 6.8 GW of capacity by 2033 and 2.1 GW of combustion turbine (CT) capacity by 2031.⁵² In the NCUC's order with respect to the resource plans, the Commission found that "... the proposed new natural gas CT and CC generation is needed and consistent with the requirements of the Carbon Plan Statute, including the requirement to maintain or improve upon the adequacy and reliability of the existing grid." The NCUC approved three CC units and four 425 MW CT units that have been selected to begin development and procurement activities, though each will still be required to apply for a Certificate of Public Convenience and Necessity (CPCN).⁵³ The South Carolina Public Service Commission (SC PSC) approved the resource plan.⁵⁴

Duke has been working to increase its supply of pipeline-delivered gas for over a decade. In April 2014, Duke and Piedmont issued RFPs for incremental FT service due to their existing and future natural gas generation requirements, core load growth, and system reliability and supply diversity goals. As a result of the RFP, Duke contracted with the Atlantic Coast Pipeline (ACP) for a portion of the 1.5 Bcf/d of FT with receipt in West Virginia and delivery in Virginia and North Carolina that would have been created by the project.⁵⁵

In 2020, after ACP was cancelled, Duke's IRP indicated that Duke would "still need additional firm interstate transportation service to support existing and future gas generation in the Carolinas despite the cancellation of the project. The 2020 IRP assumes incremental firm transportation service volumes as contemplated in the ACP project are needed from alternate pipeline providers

⁵⁰ Georgia Power All-Source Capacity Request for Proposals for 2029–2031, filed June 20, 2024 in Georgia Public Service Commission Docket No. 55268, page 16.

⁵¹ *Id.*

⁵² Supplemental Planning Analysis for 2023 Carolinas Resource Plan, pages 47-48.

⁵³ See Order Accepting Stipulation, Granting Partial Waiver of Commissions Rule R8-60A(d)(4), and Providing Further Direction for Future Planning, Filed November 1, 2024 in North Carolina Utilities Commissions docket No. E-100, SUB 190, pages 113-114.

⁵⁴ Order No. 2024-767, South Carolina Public Service Commissions, filed in Docket Nos. 2023-8-E and 2023-10-E, November 25, 2024.

⁵⁵ FERC, Atlantic Coast Pipeline and Supply Header Project Final Environmental Impact Statement, July 2017, Docket Nos. CP15-554-000, CP15-554-001, and CP15-555-000 FERC/EIS-0274D, https://www.ferc.gov/sites/default/files/2020-05/volume-1_9.pdf, page 1-4

to cost effectively support both existing natural gas generation fleet and future combined cycle natural gas generation growth.”⁵⁶

Duke’s 2023 Carolinas Carbon Plan confirmed that “combined cycle fleet is currently deficient of interstate pipeline firm transportation capacity due to the cancellation of [ACP]” as “[t]he need for additional firm transportation and diversity of gas supply, which formed the basis of the ACP project, have not changed.” Duke’s 2023 IRP therefore included the “same additional interstate firm transportation volumes for existing generation assumed in both the ACP project and the Companies’ 2020 [IRP], which are required to cost-effectively and reliably support the existing natural gas generation fleet.”⁵⁷

Duke has stated that contracted firm transportation rights on SSE and MVP Southgate are needed in order to meet their forecasted FT requirements for existing generation and new CCs 1-3.⁵⁸ In fact, as shown in Table 15 and Table 16, the FT provided by SSE is supports both existing FT demand and new project requirements, as Duke’s existing FT holdings can only meet a fraction of the existing CCs’ demand. Additional discussion of the MVP Southgate project is included in Section 2.7.

Table 15: Duke Carolinas – Interstate FT CC Requirements⁵⁹

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

⁵⁶ Duke Energy Carolinas 2020 Resource Plan, https://psc.ky.gov/psccef/2020-00349/dspenard%40strobobarkley.com/04012021034131/2021.04.01_kyseia_response_ku_lge_7_attachment_2.pdf, page 198.

⁵⁷ Duke Energy, Carolinas Carbon Plan, Appendix N: Fuel Supply, <https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-carbon-plan/supplemental/appendix-n.pdf?rev=ada7612926ea478b80ce4c7312a18343>, page 7.

⁵⁸ See Rebuttal Testimony of Verderame and Mitchell, North Carolina PUC Docket No. E-11, Sub 190, page 11, line 3 through page 13, line 2.

⁵⁹ *Id.*, see table 1.

Table 16: Duke Carolinas – Interstate FT Rights⁶⁰

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

CC1, also known as Person County CC Plant, received a CPCN from the NCUC on December 6, 2024.⁶¹ The Person County CC will be located at the same site as the existing Roxboro coal generation, and will utilize some of the transmission infrastructure from the site. Therefore, Roxboro Units 1 and 4 will retire when the new CC is placed into service.⁶²

Duke submitted an application for a CPCN for a second combined-cycle facility located at the Roxboro site (CC2 per the accepted resource plans) on February 7, 2025.⁶³ Testimony from Duke indicates that SSE will be part of the portfolio of FT that supplies the project.⁶⁴ A CPCN for CC3 can be expected to follow later in 2025.

Georgia Power

Georgia Power’s 2025 IRP notes that many actions being taken to meet the utility’s expected capacity deficit were approved in previous IRPs:

Georgia Power is addressing capacity needs through the winter of 2030/2031 through actions approved by the Commission in the 2022 IRP and 2023 IRP Update. For example, current activities include the addition of more than 2,065 MW of battery energy storage systems (“BESS”) and combustion turbine (“CT”) resources by the end of 2027, plus the

⁶⁰ *Id.*, see table 2.

⁶¹ Order Granting Certificate of Public Convenience and Necessity, North Carolina Utilities Commission Docket Nos. E-2, SUB 131 and EC-67, SUB 55, December 6, 2024.

⁶² *Id.*, page 7-8.

⁶³ Joint Application for a Certificate of Public Convenience and Necessity, Duke Energy Progress and North Carolina Electric Membership Corporation, filed February 7, 2025 in Docket Nos. E-2, SUB 1349 and EC-67, SUB 57.

⁶⁴ Direct Testimony of H. Lee Mitchell, IV, on Behalf of Duke Energy Progress, LLC, North Carolina PUC Docket No. E-11, Sub 190, filed February 7, 2025, see page 15, line 8 through page 18, line 6.

Company's active RFPs for up to 9,500 MW of capacity and more than 3,500 MW of renewable energy resources by the end of 2030.⁶⁵

The All-Source Capacity RFP for 2029-2031 was issued on June 20, 2024, and solicitations are being evaluated, with certification filings expected in July 2025.⁶⁶ The All-Source RFP indicates that proposed resources may include standalone energy storage, energy storage paired with renewables and thermal generation fueled by natural gas, oil or other fuels.⁶⁷

While the outcome of this All-Source RFP remains uncertain, it is notable that Georgia Power initiated a separate BESS RFP following the IRP Update Order.⁶⁸ In the resource mix study from the 2023 IRP, 1,230 MW of CT capacity was added in 2027 and 2028, along with 3,600 MW of CC capacity was added in 2030 and 2031, based on the moderate gas, lower carbon pressure (MGO) scenario. This scenario represents the base case assumptions for CO₂ and other GHG pressures, generating technology costs and performance, load growth, and fuel prices.⁶⁹ In the 2025 IRP's MGO scenario, the model selected 2,400 MW of CT capacity and 5,100 MW of CC capacity for development between 2029 and 2031. Additionally, the 2025 IRP includes an alternative base case that accounts for carbon emissions limits under the EPA's Section 111 GHG Rules. Under this scenario, Georgia Power's capacity expansion model opted to build 2,400 MW of CT capacity and 4,200 MW of CC capacity between 2029 and 2031.⁷⁰

2.2 Other Electric Utilities in the Southeast Plan on Increasing Gas-Fired Generation

Besides Duke Carolinas and Georgia Power, approximately 3.9 GW of new gas-fired power capacity is expected to be commercialized between 2025 and 2031. About 90% of this capacity is proposed as CC units.⁷¹ About 45% of the gas-fired capacity additions are planned for Southeast Electric Reliability Council (SERC) East (North Carolina and South Carolina), with the remaining capacity in SERC Southeast (Georgia, Alabama, and Mississippi). Most of these projects are in the early development stages, either announced or in the permitting process. With increasing load growth outlined in their most recent IRPs, Oglethorpe Power, Santee Cooper, Dominion Energy

⁶⁵ Georgia Power 2025 Integrated Resource Plan, Georgia Public Service Commission Docket No. 56002, January 2025, pages 2-3.

⁶⁶ *Id.*, page 13.

⁶⁷ All-Source Capacity RFP for 2029–2031 RFP Document Final Approved, Georgia Public Service Commission Docket No. 55268, June 20, 2024, pages 20-21.

⁶⁸ Georgia Power 2025 Integrated Resource Plan, page 11.

⁶⁹ Georgia Power 2023 Integrated Resource Plan Update, filed October 2023 in Georgia Public Service Commission Docket No. 55378, PD Capacity Expansion Plans Supplemental

⁷⁰ Georgia Power 2025 Integrated Resource Plan, filed January 31, 2025 in Georgia Public Service Commission Docket No. 56002, Volume 2, Capacity Expansion Plans - 2025 IRP

⁷¹ Dominion Energy South Carolina 2024 IRP, filed March 28, 2024, page 3, 29

<https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/company/irp/sc/desc-integrated-resource-plan-2024.pdf?rev=42a0728dbf894c979aefc95151401fcb>

Santee Cooper 2024 IRP Update, file September 16, 2024, page 8

<https://www.santeecooper.com/About/Integrated-Resource-Plan/Reports-and-Materials/Santee-Cooper-2024-IRP-Update.pdf>

Oglethorpe Power New Generating Project, Accessed February 2025, <https://opc.com/newgeneration/>

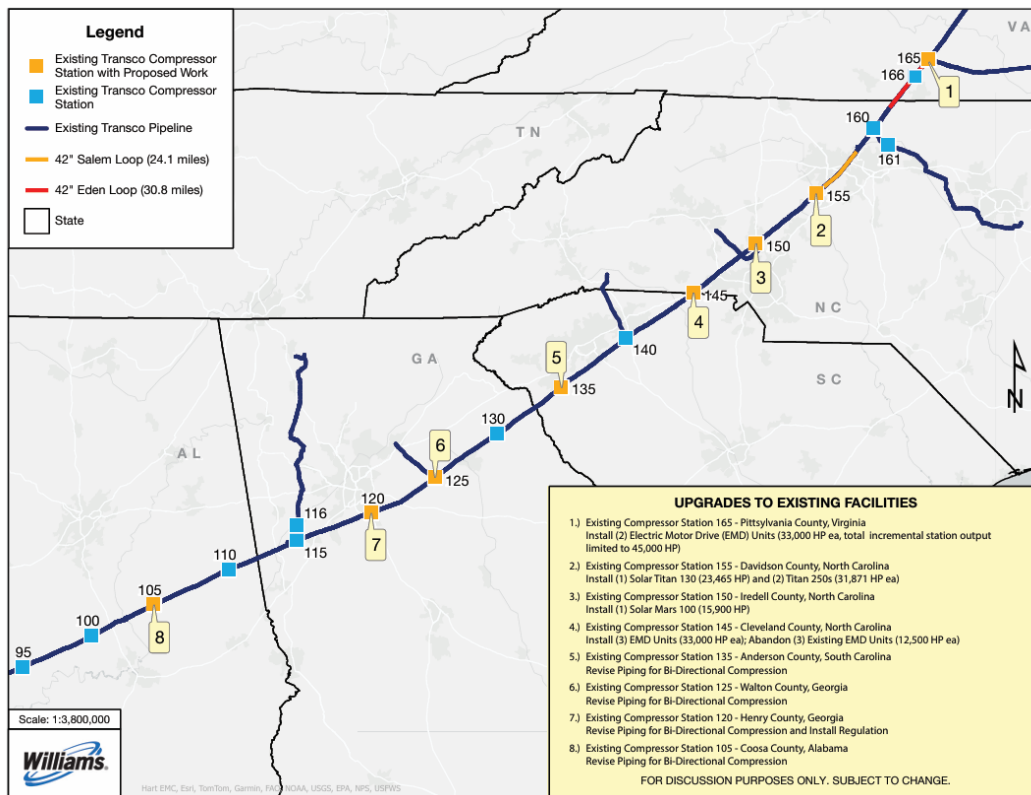
South Carolina, and Alabama Power plan to add new capacity between late 2025 and 2031, including gas-fired resources to support reliability and meet demand.

Additional detail about these additions is provided in Section 4.1.

2.3 Review of Firm Transportation Entitlements Confirms Limited Slack Capacity in the Study Region

Per the filed Resource Report, SSE will provide an incremental 1,596.9 MDth/d of year-round firm transportation capacity with receipt at Transco’s existing Station 165 Zone 5 Pooling Point and the Cherrystone Interconnect with Mountain Valley Pipeline located near MP 1413.0 in Pittsylvania County, VA. About 1,300 MDth/d will be deliverable as far south as the Station 85 Zone 4 Pooling Point, which stretches to the Alabama-Mississippi border.⁷² 300 MDth/d of SSE capacity will be deliverable to Transco’s existing Eden Meter Station near MP 1382.5 and Transco’s existing Dan River #2 Meter Station located near MP 1382.7 both in Rockingham County, NC, which are north of Station 155 (point 2 in Figure 4, below), with smaller amounts deliverable on other paths.⁷³

Figure 4: SSE Project Map



⁷² Zone 4 begins at Station 65, which is at the Louisiana-Mississippi Border.

⁷³ SSE Resource Report No. 1: General Project Description, May 2024. See page 1-4. Filed under FERC docket No. PF-24-2.

A review of Transco’s firm entitlements confirms that there is little to no unsubscribed capacity that can deliver gas into the study region.

- LAI review of Transco’s index of customers indicates that there is currently 2,335 MDth/d of firm entitlements that flow north to south across the Virginia-North Carolina border.⁷⁴ This is greater than the design capacity of 2,222 MDth/d of mainline milepost 1369.45 in northern North Carolina, which is the closest segment to the Virginia-North Carolina border that reports north-to-south design capacity.
- South-to-north, there is 5,247 MDth/d of firm entitlements that flow from the gulf states through station 85 into Alabama. The closest station included in Transco’s operational capacity report is compressor station 90 in Alabama, with design south-to-north flows of 5,310 MDth/d. Additional detail around which entities hold FT in the study region is found in Section 4.2, with respect to the Gas Constraint deployed in Aurora modeling.

2.4 Pipeline Utilization into the Study Region is High

In addition to Transco’s FT entitlements being fully subscribed, key segments on Transco and SNG, the only other major interstate pipeline serving the region, have been heavily utilized.

Transco North to South

As Transco noted in its Resource Report filing:

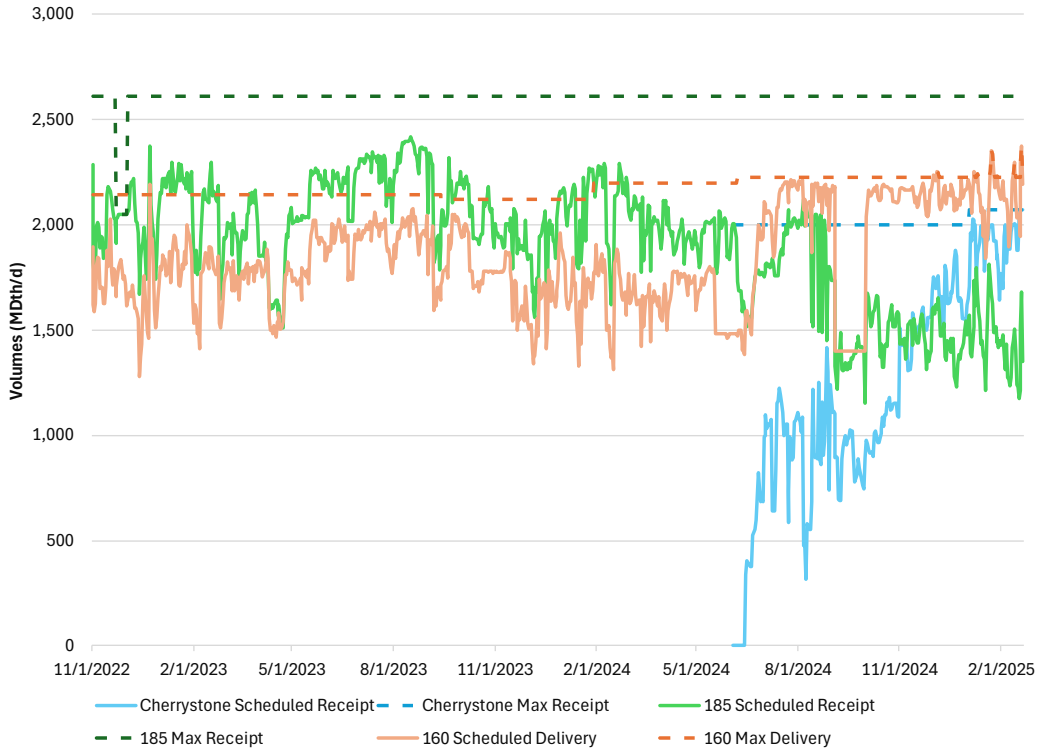
Supply access in Zone 5 is currently constrained by existing pipeline capacity. Transco’s system data from January 1, 2021, through January 15, 2024, shows that non-primary southbound capacity nominated through Transco’s Station 160 constraint was restricted every day. Southbound flow was limited to natural gas quantities nominated under primary firm transportation and non-secondary reverse path rights (Transco’s highest tier of non-primary transportation service) on 85% of the days in that period.⁷⁵

This is borne out through scheduled volumes data available on Transco’s Electronic Bulletin Board (EBB). As shown in Figure 5, below, receipts from MVP at the Cherrystone interconnect have grown close to maximum capacity of 2,000 MDth/d, while throughput at Station 160 has not increased commensurately, and the segment remains at or near capacity. Meanwhile, throughput and utilization at Station 185 has dropped. Hence, supply from MVP is replacing existing pathways rather than providing fully incremental capacity. Though additional supplies from MVP are being utilized to meet deliveries in Zone 5 North (Virginia), SSE (and MVP Southgate) is needed to fully unlock supply from MVP.

⁷⁴ Williams, Transco, Index of Customers. <https://www.1line.williams.com/Transco/index.html>

⁷⁵ SSE Resource Report No. 1: General Project Description, May 2024. See pages 1-4, 1-5.

Figure 5: Scheduled Volumes, Selected Zone 5 Segments⁷⁶

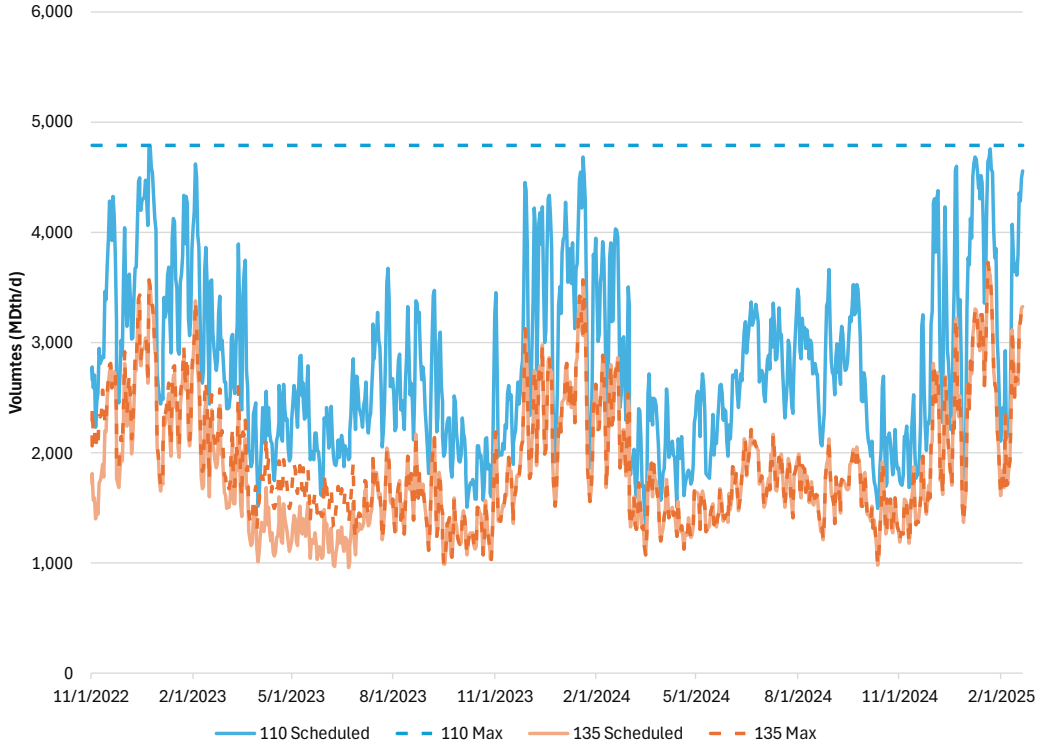


Transco South to North

With the advent of Marcellus shale, Transco now has two main sources of supply, the original receipts from the Gulf Coast and Marcellus. The point where the direction of flow on Transco switches from north-to-south to south-to-north is called the null point. The null point on the Transco system is fluctuating between different points in Zone 5. The null point typically resides between the aforementioned Station 160 and Station 135 on the Georgia-South Carolina border. Consequently, volumes flowing through Station 135 are typically reported as south to north, while volumes at Station 150 are typically reported as north to south. Station 110 is the closest station to the Alabama-Georgia border. Flows south to north across this station are near capacity on cold winter days. Figure 6 shows flows across these two segments.

⁷⁶ Design capacity, rather than operating capacity, is reported for "Station 160 Mainline Milepost 1369.45 N To S NL" as a replacement for Station 160 since Transco stopped reporting data for Station 160 in June 2024.

Figure 6: Scheduled Volumes, Select Zone 4, Zone 5 Segments

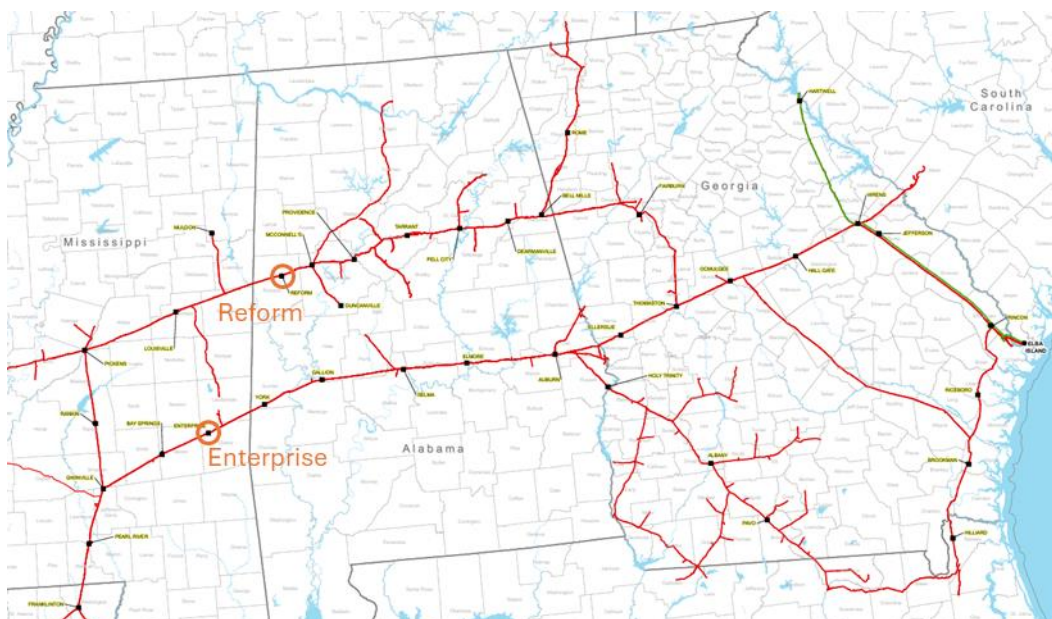


As noted, Station 135 typically operates at less than its 3,856 MDth/d design capacity from south to north. Apparently, counterflows often limit available capacity on this segment path. This means that gas flow into the Carolinas is also restricted from the south.

Southern Natural Gas

Southern Company and other utilities in SERC Southeast receive gas from SNG, an interstate pipeline owned by Kinder Morgan. SNG has four zones (0-3). The border of SNG Zones 1 and 2 is along the Mississippi-Alabama border, and border of Zones 2 and 3 is along the Alabama-Georgia border. SNG lists the Enterprise and Reform compressor stations prominently on its segment capacity map, and these two stations are near the Zone 1-2 border. The alignment of zonal and geographic boundaries with pressure changes at these compressor stations makes this the natural boundary of the study region for purposes of gas constraint modeling.

Figure 7: Selection of SNG System Map



SNG's southern line runs through the Enterprise station and represents the main line in terms of capacity, while the smaller northern line runs through the Reform station. Both lines deliver gas to the Atlanta area, so some gas flows north from the Thomaston compressor station on the main line towards Atlanta.

While scheduled flows data indicates that about 940 MDth/d is available across the Enterprise and Reform segments on average, there are many days, particularly during the winter, where far less transportation capacity is available. In the duration curve below, available capacity at Enterprise and Reform are summed. This sum may not account for downstream constraints and may therefore overestimate available capacity. Available capacity on the Enterprise mainline is less than 460 MDth/d (Southern Services' FT quantity on SSE) on about 30% of sampled days, and is close to zero on some peak days. Given that gas-fired generators will need FT or backup fuel available on all days, particularly during peak conditions, it is clear that available capacity is insufficient to support the incremental gas requirements to support the dispatch regime of the new combined-cycle additions.

Figure 8: SNG Selected Scheduled Volumes

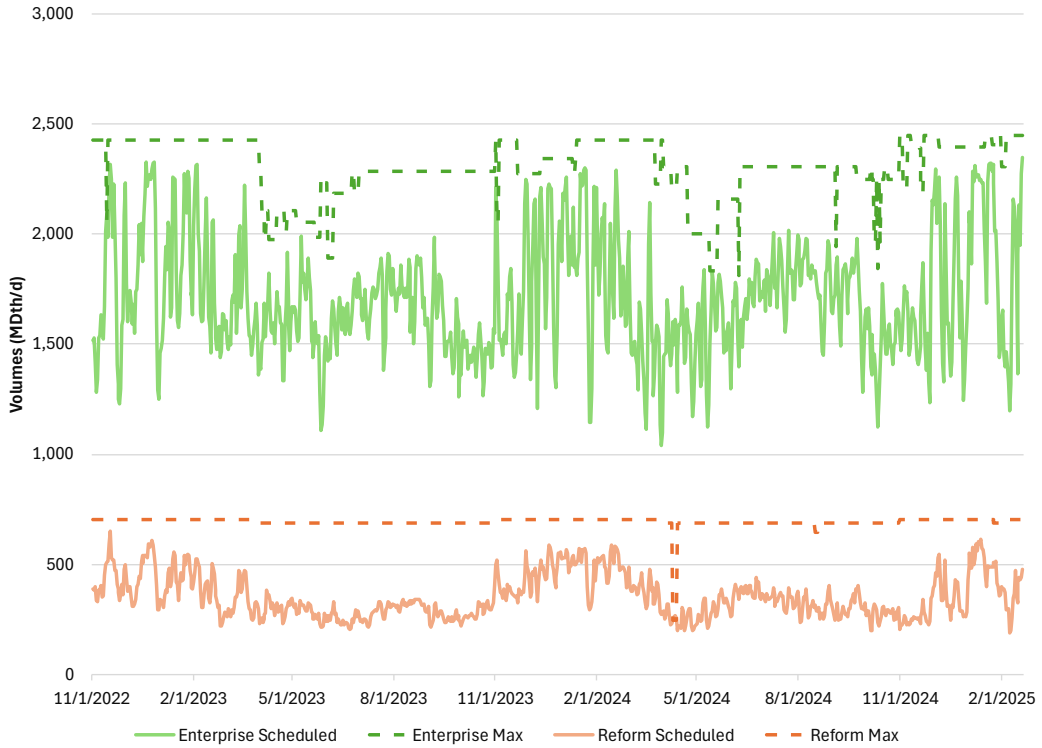
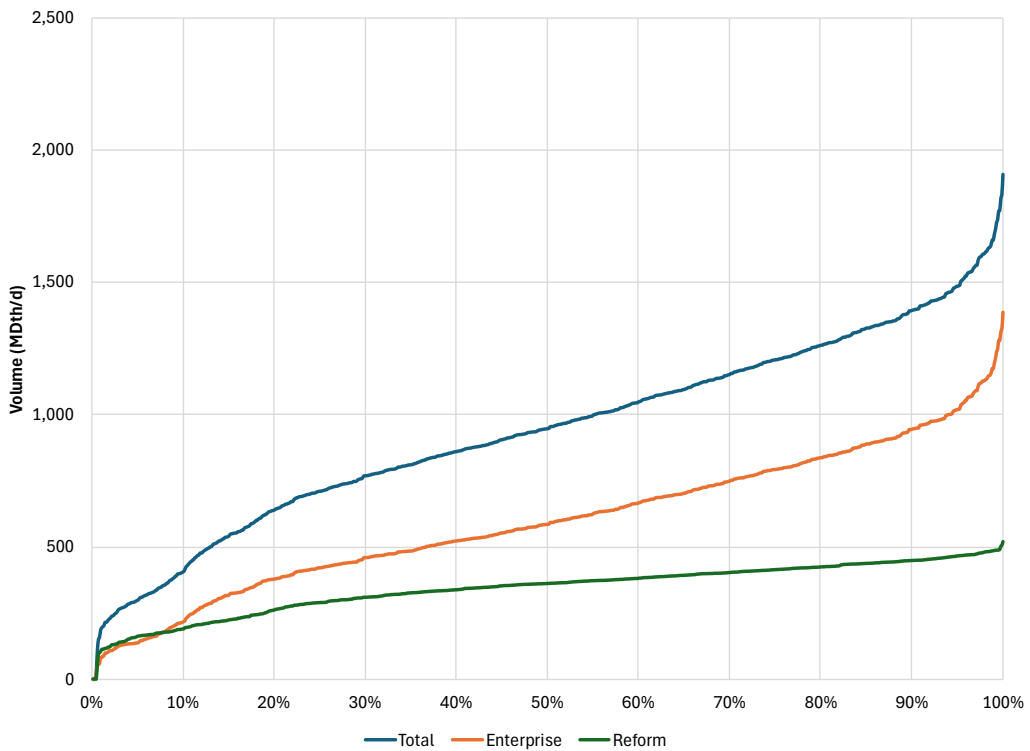


Figure 9: Duration Curve, Available Capacity



Moreover, SNG is already working with Southern Services and other shippers on SNG South System Expansion 4 (SSE4), a 1,323 MDth/d expansion on the main line that would reach to the east end in South Carolina. As discussed in 4.2, below, SNG has recently entered the pre-filing process for FERC certification.⁷⁷ Like SSE, SNG SSE4 is one of several solutions that will be necessary to meet growing power demand in the Southeast.

2.5 Review of Critical Operational Flow Orders on Transco

OFOs are protocols that pipeline operators declare to discourage significant deviation of customers' takes relative to their nominated quantities. OFOs are generally declared on constrained portions of pipelines in order to maintain acceptable operating pressures during particularly warm or cold conditions. Transco's zones 4 and 5, which contain the entirety of the study region, have seen a high volume of and increasingly frequent OFOs declared by Transco, implying significant infrastructure constraints. Many of these OFOs simultaneously restrict both imbalances due to and from the shipper. For example, during a 2 week stretch in early January 2025, Transco enforced an OFO in zones 4 and 5 with a 10% "due to shipper" restriction and a 5% "due from shipper" restriction (i.e. applicable pipeline customers would face penalties if their actual takes exceeded their nominations by more than 5% and would also face penalty if their nominations exceed their actual takes by more than 10%). On very cold or hot days when system demand is highest, Transco may tighten the imbalance restriction on takes in excess of nominations while lifting the restriction due to shipper in order to encourage higher nominations relative to system takes. Duke has noted the difficulties with these constraints in its 2023 Carolinas Resource Plan:

In recent years, the Transco pipeline system has become increasingly constrained and less flexible, limiting the amount of swing and daily imbalance through frequent issuance of daily Operational Flow Orders with low percentage tolerances. Given that Transco has moved to a strict daily pipeline tolerance, the Companies' flexibility is reduced to meet the need of potential daily over burns where natural gas demand has exceeded supply, potentially subjecting the Companies to daily tiered charges from Transco and penalties of \$50/Dth. Transco is proposing additional restrictions that will further limit the Companies' ability to serve their respective gas fleets as needed, especially given such a high reliance on delivered Zone 5 supply and the increasing penetration of intermittent generation. These restrictions, compounded by Transco's physical flow limitations, bind the Companies' ability to operate their respective gas fleets at full capacity throughout the year.⁷⁸

The daily OFOs clearly impact Duke's ability to operate their gas fleet without incremental FT.

⁷⁷ FERC, "Southern Natural Gas Company, L.L.C., et al. submit request to implement pre-filing review process re the proposed South System Expansion 4 Project under PF25-1.," October 30, 2024.

https://elibrary.ferc.gov/eLibrary/docinfo?accession_num=20241031-5065

⁷⁸ Duke Energy, Appendix K – Natural Gas, Low-Carbon Fuels and Hydrogen, page 3.

<https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/appendix-k-natural-gas-lowcarbon-fuels-hydrogen.pdf>

2.6 Review of Gas Pricing Dynamics in Carolinas and Georgia

Gas prices in the Southeast are higher than in gas-producing regions due to pipeline constraints and the cost of transporting gas. The two major production areas of relevance to Transco are the Gulf and Marcellus regions, of which Henry Hub and Eastern Gas South, respectively, are common benchmark indices. Due to lower production costs, gas from the Marcellus region is significantly cheaper than that of Henry Hub. In 2024, the Gas Daily average price at Henry Hub was \$2.25, which is \$0.57 higher than the 2024 average at Eastern Gas South of \$1.68. Currently, both indices that serve the Southeast, Transco Zone 4 and Zone 5 South, trade higher than Henry Hub. Transco Station 165, which would be the source of increased southbound gas enabled by SSE, trades similarly to the low-priced Eastern Gas South index during non-winter months.

As shown in Figure 10, Transco Zone 5 South trades at a premium to both Henry Hub and Eastern Gas South. In addition, delivered gas prices in the study region, especially in the Carolinas, are subject to winter price spikes when demand for gas is highest. The Gas Daily index for Transco Zone 5 South, which includes deliveries on Transco between Station 165 and the Georgia-South Carolina border, has seen price spikes in excess of \$20 in each of the past three winters. Figure 10 shows the elevated pricing of Transco Z5 South relative to gulf and Appalachian benchmark indices. Transco Zone 5 South core winter prices (December through February) have averaged \$6.02 over the past three winters, as compared to Eastern Gas South which has averaged \$2.88. Delivered prices in other months (March through November) have averaged \$2.49 at Transco Zone 5 South and \$1.47 at Eastern Gas South over the past two years.

Transco Zone 4, which includes deliveries between Station 65 and the Georgia-South Carolina border, tends to be more stable than Zone 5 South during cold spells. The index typically prices at a small premium to the Henry Hub benchmark, but the premium has been trending higher in the past year.

Figure 10: Transco Zone 4 and Zone 5 South Gas Daily Monthly Avg. vs. Benchmark Indices

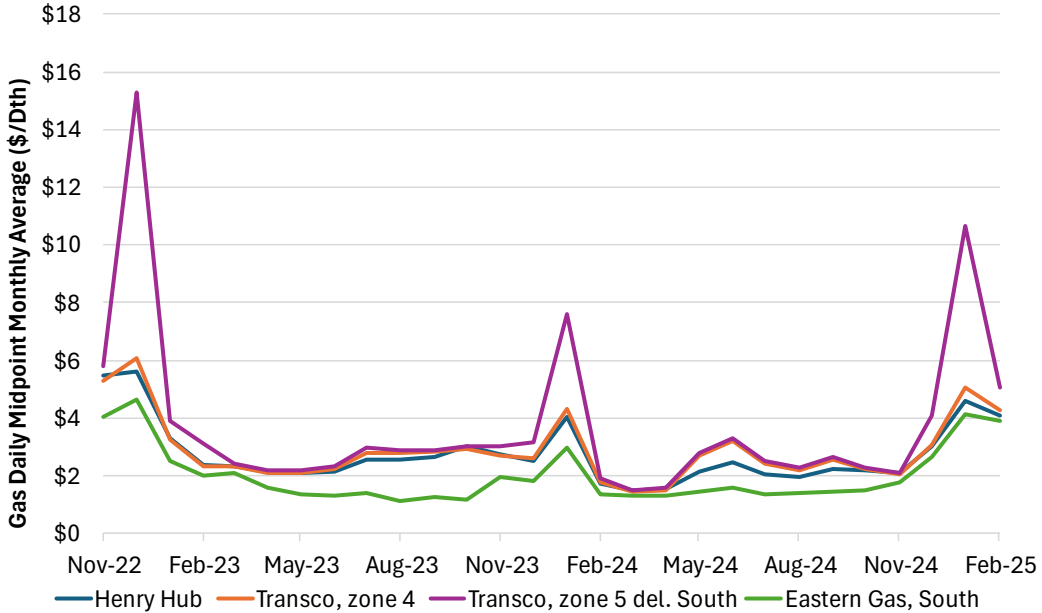
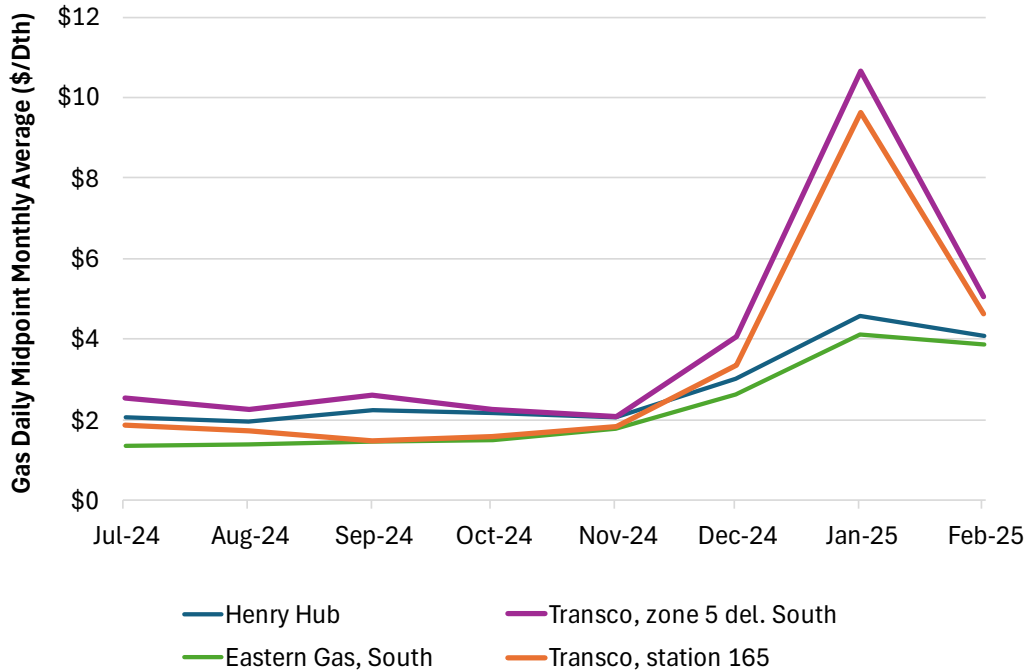


Figure 11: Transco Station 165 Monthly Average Pricing: Jul 2024-Feb 2025



Gas Daily started publishing prices for deliveries at Transco Station 165 in July of 2024. This coincided with the ramping of deliveries into Transco from the Mountain Valley Pipeline at the Cherrystone interconnect, adjacent to Station 165. During mild and warm weather, the Station 165 index has priced similarly to the Marcellus benchmark index, Eastern Gas South, due to relatively unconstrained flows from the Marcellus production areas into Transco. During cold

spells, Station 165 has exhibited price spikes similar to those of Zone 5 South. Figure 11 shows Station 165 pricing since its inception in July 2024.

SSE's capacity allows shippers to access volumes at Station 165 which have been transported from cheaper production basins in the Marcellus via MVP.

2.7 Alternatives to SSE are Insufficient to Meet Growing Demand

Transco's Resource Report considers seven categories of alternatives: "energy conservation measures; alternative energy sources; alternatives for supplying natural gas, including alternative natural gas transmission systems; route alternatives; compressor station and compressor station site alternatives; compression alternatives; and construction method alternatives."⁷⁹ In this Section, LAI analyzes the three categories of *alternatives to the SSE project, i.e., energy conservation, alternative energy sources and alternatives for supplying natural gas*. Transco's Resource Report provides discussion of the *alternatives for SSE project design and construction, including route alternatives, compressor station and compressor station site alternatives, compression alternatives, and construction method alternatives*.⁸⁰

Georgia Power and Duke already include energy conservation measures, aka energy efficiency (EE) and demand-side management (DSM), in their resource portfolios. The GA PSC requires that Georgia Power offer a DSM plan that minimizes upward pressure on rates, maximizes economic efficiency, and treats DSM as a priority resource. Georgia Power's 2025 IRP considered the impact on rates under base case with DSM performance savings targets of at least 0.75% of annual retail sales and concluded that achieving it would put significant upward pressure on rates.⁸¹ Similarly, Duke has indicated that "amount of annual EE (1% of eligible load) that is assumed to be achieved in the Carolinas Resource Plan ... that will require substantial advancement of EE in the Carolinas in unprecedented ways" and "may be leading to overly aggressive long-term EE forecasts."⁸² As shown in Table 20, between 2024 and 2031 Georgia Power's energy demand is forecast to grow at an average of 6.3% per year, while Duke is forecast for 2.1% growth, even after accounting for the assumed EE. Thus, Duke and Georgia Power cannot rely on energy conservation as an alternative to the SSE Project.

Duke and Georgia Power have identified gas-fired generation as necessary to meet resource adequacy requirements to provide reliable power supply as electricity demand grows.⁸³ Duke has targeted reducing coal and oil-fired capacity by 4.9 GW from 2031 to 2038. Other options aside from coal and oil are limited. Duke does not contemplate the addition of new nuclear generation

⁷⁹ Transco Resource Report 10, p. 10-1.

⁸⁰ *Id.*, Sections 10.5 to 10.8.

⁸¹ Georgia Power 2025 IRP, pp. 51-52.

⁸² Duke, 2023 Carolinas Resource Plan, Appendix H, pp. 4 and 9.

⁸³ The North American Electric Reliability Corporation defines Adequacy as "The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components"

See 2024 Long-Term Reliability Assessment, December 2024, page 139.

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf

until 2035.⁸⁴ Duke's resource adequacy analysis in support of the 2023 Resource Plan included Effective Load Carrying Capability (ELCC) calculations, which estimate the percentage of nameplate capacity that contributes to meeting load in various clean energy portfolio configurations:

The winter storage ELCC's are at or near 100% for the first couple of battery tranches, but eventually these values will drop dramatically given winter load shapes can remain high across the day. Once enough storage is on the system, the net loads flatten to the point storage is needed in both the evening and morning peaks with limited reserve capacity available throughout the night to recharge the batteries. Solar values remain low during the winter as the risk of load shed is mostly during the early morning hours. The ELCC of onshore wind is in the 30-40% range while the ELCC of offshore wind was calculated to be north of 60%.⁸⁵

In fact, the Supplemental Planning Analysis identifies *more* gas-fired generation beyond what SSE is capable of serving, in the form of two additional combined-cycle units, as necessary to meet demand in 2032 and 2033.⁸⁶ SSE also benefits Duke by providing additional FT to cover existing combined-cycle generation that does not have diesel backup. About 1,800 MW of winter capacity at Buck, Dan River, and WS Lee plants do not have backup fuel capability.⁸⁷

Under the 2025 IRP, Georgia Power will continue to operate Plant Bowen Units 1-4, which represent about 3.4 GW of coal-fired capacity.⁸⁸ Georgia Power is deferring any new retirements of fossil generation unit the mid-2030s.⁸⁹ In the IRP Resource Mix Study, the ELCCs assumed for solar PV and onshore wind power were zero and 35%, respectively. ELCC of four-hour storage resources decline rapidly, from 95% at 0-3,000 MW of nameplate to 25% at 9,001 MW or more.⁹⁰ Conventional gas-fired generation with fuel security typically would have ELCCs of 90% or greater, as they have low unplanned outages rates and high availability. Almost all of the 5,150 MW of existing combined-cycle capacity owned by Southern Power Company lacks diesel backup capability.⁹¹ Gas-fired capacity has been identified as important to meeting demand, and both

⁸⁴ Duke, Supplemental Planning Analysis Technical Appendix, Tables SPA T-10 and T-11.

<https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/supplements/technical-appendix-to-supplemental-analysis.pdf>

⁸⁵ Duke Energy Carolinas and Duke Energy Progress Effective Load Carrying Capability (ELCC) Study, prepared for Duke Energy by Astrapé Consulting, April 25, 2022, see page 18.

<https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/attachment-02-2022-elcc-study.pdf>

⁸⁶ Duke Supplemental Planning Analysis page 48.

⁸⁷ U.S. Energy Information Administration, Form EIA-860 detailed data, 2023 Final. See sheet 3, generator level data. <https://www.eia.gov/electricity/data/eia860/xls/eia8602023.zip>

The steam turbine component of the Buck combined cycle train cannot operate when combustion turbines are running on diesel, but these combustion turbines can bypass the heat recovery steam generator and steam turbine while operating on diesel.

⁸⁸ Georgia Power 2025 IRP, page 63.

⁸⁹ *Id.*, Table C.1 on pages 125-126.

⁹⁰ Georgia Power 2025 Integrated Resource Plan Resource Mix Study, January 2025, Table 5 on pages 25-26. Filed January 31, 2025 in Georgia Public Service Commission Docket No. 56002

⁹¹ U.S. Energy Information Administration, Form EIA-860 detailed data, 2023 Final. See sheet 3, generator level data.

Duke and Georgia Power have identified needs for additional gas-fired generation capacity beyond what SSE can fuel.

With respect to alternative sources of natural gas, the SSE study region is served by three interstate natural gas pipeline systems, Transco, SNG and East Tennessee Natural Gas (“ETNG”). As shown in Figure 4, Transco serves all of the states in the study region, whereas SNG serves Georgia, Mississippi, Alabama and southwestern South Carolina, as shown in Figure 7. Expanding Transco is not an alternative to the SSE because the SSE is the planned expansion of Transco’s system to serve the study region. ETNG serves northwestern Georgia, where it delivers gas to Atlanta Gas Light and through its interconnect with Transco near the Virginia-North Carolina border. ETNG is not an alternative to the SSE project because ETNG does not serve the Carolinas, the Ooltewah compressor station capacity limits ETNG deliveries to Georgia to 182 MDth/d, and none of the currently contemplated ETNG expansions would increase capacity deliverable to the study region.^{92,93}

SNG has requested that FERC begin pre-filing review of the SNG SSE4 Project which create up to approximately 1,323 MDth/d of capacity deliverable to SNG customers in Georgia, South Carolina, Alabama and Mississippi.⁹⁴ The project is mainly comprised of upgrades on the southern main line starting at the Enterprise compressor station. Concurrently, Kinder Morgan has also entered pre-filing for the Mississippi Crossing (MSX) project, which would add capacity to SNG’s interconnections with other pipelines.⁹⁵ SNG “held an open season from June 27, 2024, through July 12, 2024, and subsequently entered into commercial agreements with Dominion Energy South Carolina, Inc.; Oglethorpe Power Corporation; Southern Company Services, Inc.; Atlanta Gas Light Company; City of Austell Natural Gas System; and Municipal Gas Authority of Georgia ... for the full capacity to be created by the Project.”⁹⁶ Both SNG SSE4 and MSX obtained pre-filing approval on December 12, 2024 and have the scoping period running from March 3, 2025 through April 7, 2025. There is some overlap between the SNG and SSE shippers, as Southern Company Services, Atlanta Gas Light and the Municipal Gas Authority of Georgia have subscribed for capacity on both projects. Continued expansion of the SNG system does not represent a viable alternative to the SSE project because SNG SSE 4 is fully subscribed and does not deliver to the Carolinas.

⁹² East Tennessee Natural Gas, LLC, Peak Day capacity map, April 2, 2025, .

⁹³ Enbridge, “Enbridge’s Energy Infrastructure Projects,” February, 4, 2025.

https://www.enbridge.com/~media/enb/documents/factsheets/fs_energyinfrastructureprojects.pdf?la=en

⁹⁴ Southern Natural Gas Company, L.L.C., DRAFT Resource Report 1 General Project Description, South System Expansion 4 Project

Docket No. PF25-1-000, April 2025, pp. 1-1.

⁹⁵ SNG SSE4 and MSX are not included in the shared assumptions for GPCM and the Aurora gas constraint. These projects are at a similar development state as SSE, and less information has been shared about the shippers and contract paths thus far in the pre-filing process.

⁹⁶ Id, pg. 10-2.

Table 17: SNG SSE4 Customers and Subscribed Capacity⁹⁷

Shipper	Subscribed Capacity (Dth/d)	End Use
Dominion Energy South Carolina	470,000	Power Generation/Local Distribution
Southern Company Services	385,000	Power Generation
Oglethorpe Power Corporation	248,529	Power Generation
Atlanta Gas Light	200,000	Local Distribution
City of Austell	15,000	Local Distribution
Municipal Gas Authority of Georgia	4,550	Local Distribution
Total	1,323,079	

While Southern Company has not finalized the allocation of SSE capacity to its subsidiaries, LAI’s analysis shows that 400 MDth/d of SSE capacity would be needed to serve 3,000 MW of Georgia Power’s new gas-fired generation under the requirements in their current All Source RFP.⁹⁸ Therefore, Southern Company’s South System Expansion 4 capacity will be needed to serve gas-fired generation serving Alabama Power and Mississippi Power or potentially incremental demand for gas-fired generation needed to meet resource adequacy targets after 2031. Municipal Gas Authority of Georgia only accounts for 2 MDth/d of SSE capacity and Atlanta Gas Light 2025 capacity plan indicates that, even after accounting for its SSE capacity, Atlanta Gas Light will still “need to proactively subscribe to capacity in large blocks ... to meet the projected needs of customers, and to stay ahead of the growth curve as much as possible to avoid stalling growth and economic development.”⁹⁹

LAI’s review of major pipeline projects pending before FERC identified one project that could serve North Carolina - the Mountain Valley Pipeline Southgate Project (Southgate Project).¹⁰⁰ The Southgate Project is expected to be in service by mid-2028 and would transport natural gas from an interconnection point with the MVP Mainline Project in southern Virginia to an interconnection point with ETNG in North Carolina, and then to two new delivery points in Rockingham County, North Carolina, the terminus of the Southgate Project. 300 MDth/d of Southgate Project capacity is under contract with Enbridge Gas North Carolina. 250 MDth/d is under contract with Duke.¹⁰¹ LAI included MVP Southgate capacity in all gas and electric modeling, consistent with Duke’s resource planning which assumes the availability of MVP Southgate capacity. The Southgate Project is fully subscribed, as is the MVP Mainline project.¹⁰²

⁹⁷ Southern Natural Gas Company, L.L.C., DRAFT Resource Report 1 General Project Description, South System Expansion 4 Project

Docket No. PF25-1-000, December April 2025, pp. 1-2.

⁹⁸ Georgia Power All Source RFP Section 3.10.1.B.

⁹⁹ Atlanta Gas Light, 2025-2034 Integrated Capacity and Delivery Plan, Docket No. 43820, February 1, 2024 pg. 33.

¹⁰⁰ FERC, Major Pipeline Projects Pending, updated March 04, 2025 <https://www.ferc.gov/industries-data/natural-gas/major-pipeline-projects-pending>.

¹⁰¹ MVP Southgate Amendment Project, Resource Report 1 – General Project Description, Docket No. CP25-60., Amended February 2025, pg. 1-2.

¹⁰² Mountain Valley Pipeline. <https://mountainvalleypipeline.info/>

Because the Southgate Project earmarks all deliverability benefits to North Carolina, it is not a substitute for the SSE, which is designed around operational flexibility to serve the Carolinas and Georgia. MVP Southgate is also a much smaller project than SSE.

Kinder Morgan recently announced that its Elba Express pipeline has executed a precedent agreement for a 71-mile extension of its system into South Carolina. Kinder Morgan has indicated that the approximately \$431 million Elba Express Bridge project will provide 325 MMcf/d of firm transportation capacity deliverable in South Carolina, supported by long term contracts with credit-worthy customers. Kinder Morgan anticipates that the project could be placed in service in the second quarter of 2030, assuming the timely receipt of all required permits and approvals.¹⁰³ The Elba Express Pipeline only receives gas from interconnects with Transco and SNG, and both Transco and SNG already can deliver gas to the study region. Therefore, expansion of Elba Express does not represent a substitute for the SSE project.

Vaporized LNG is a substitute for pipeline-delivered natural gas. However, LNG vaporization requires large investments in facilities for LNG storage and vaporization. Smaller volumes of LNG can be delivered by truck, but larger LNG storage facilities typically either have on-site liquefaction capacity or take delivery from ocean-going LNG tankers. Elba Island, the only facility in the region with substantial vaporization and storage capacity, became export capable in 2019 and has been committed to the export market since 2022.¹⁰⁴ Elba Island reduces liquefaction and vaporizes LNG for injection into U.S. pipelines during extreme winter storms, but this has a small impact on the overall balance of LNG trade.¹⁰⁵

LNG can be relied upon for peaking supplies, but cannot replace mainline deliverability that enables year round utilization. For example, Dominion's Brunswick-Greenville Storage Facility has an estimated cost of \$547 million. When completed, Dominion's Brunswick-Greenville Storage Facility will have 2 BCF of storage capacity, 15 MDth/d of liquefaction capacity and 500 MDth/d of vaporization capacity.¹⁰⁶ When inventory is topped, the Brunswick-Greenville Storage Facility can provide 500 MDth/d for up to four days. However, over longer periods the facility's 15 MDth/d of liquefaction capacity is also the limit on average daily vaporization.

¹⁰³ Kinder Morgan Reports First Quarter 2025 Financial Results, April 16, 2025, <https://ir.kindermorgan.com/news/news-details/2025/Kinder-Morgan-Reports-First-Quarter-2025-Financial-Results/default.aspx>.

¹⁰⁴ Elba's export capacity is fully contracted under a 20-year tolling agreement with Shell. See Natural Gas Weekly Update for the week ending October 16, 2019, U.S. Energy Information Administration. Accessed March 31, 2025. https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/10_17/

¹⁰⁵ Answer of Southern LNG to Protest and Renewed Request for Approval, filed February 20, 2024 in FECM Docket No. 23-109-LNG. <https://www.energy.gov/sites/default/files/2024-02/2022.02.16%20-%20SLNG%20Answer%20to%20Protest.pdf>

¹⁰⁶ Virginia State Corporation Commission, Final Order, February 24, 2025, CASE NO. PUR-2024-00096, pp. 2-3. <https://www.scc.virginia.gov/docketsearch/DOCS/83zm01!.PDF>

3 SSE Incremental Deliverability Yields Economic Benefits

Gas price analysis was performed using RBAC’s Gas Pipeline Competition Model (GPCM). GPCM is a standard modeling tool used by many major industry participants including pipeline operators, storage facility owners, regulators, and consultants. Notable organizations that utilize GPCM include FERC,¹⁰⁷ MISO,¹⁰⁸ and S&P Global.¹⁰⁹ GPCM is a network partial equilibrium model which simulates North America’s production, interstate pipelines, storage facilities, and the entitlements associated with gas customers. In a partial equilibrium model, the economic equilibrium condition analyzes a specific but-for scenario in which certain conditions are different. Hence, all else remains constant, except for the changes being analyzed.¹¹⁰ Pipelines are represented by a series of zones. Each zone may have links to production areas, storage facilities, interconnections with other pipelines, and/or to end users. Monthly demand curves for the end users and capacities for the pipeline links and zones are input into GPCM. Model outputs include average monthly zonal prices, pipeline utilization levels, and deliveries to end users.

In this Section we review the general structure of the GPCM model. We identify modifications implemented by LAI to the GPCM base case. We then report the comparison of price impacts with SSE and without SSE cases.

3.1 Structure of GPCM Analysis

The originating structure for the GPCM analysis was RBAC’s Q1-2025 base case, which was the most recent available at the time of this study. LAI’s changes to the natural gas infrastructure modeled in the GPCM base case include updates to the Transco SSE project, the MVP Southgate project, and the capacity of certain pipeline interconnections within the study area. In addition, GPCM’s “Autoexpand” feature, which automatically increases severely constrained pipeline segments, was turned off for Transco, consistent with the general structure of a “but-for” test. LAI’s GPCM model runs included a “with SSE” scenario and a “without SSE” scenario. In the “without SSE” scenario, any updates to the GPCM zones and links associated with the SSE project were turned off. LAI’s analysis assumes that the SSE project is commercialized in November 2027.

Modifications to electric customer’s demand curves were derived from output from the Aurora model, which is detailed in Section 4.¹¹¹ GPCM’s Power Model Interface (PMI) was used to convert Aurora generator gas consumption into customer-specific demand curves in GPCM. The new demand curves were made perfectly inelastic, such that the GPCM deliveries to study area generation were “forced” to equal the PMI output.

¹⁰⁷ Federal Energy Regulatory Commission, Winter 2014-15 Energy Market Assessment, October 2014. <https://www.ferc.gov/sites/default/files/2020-05/10-16-14-A-3.pdf>

¹⁰⁸ Midcontinent Independent System Operator, Long Range Transmission Planning, September 2024. <https://cdn.misoenergy.org/MTEP24%20Chapter%20%20-%20Regional%20Long%20Range%20Transmission%20Planning658124.pdf>

¹⁰⁹ S&P Global, Methodology and Specifications Guide, December 2024. https://www.spglobal.com/commodityinsights/PlattsContent/_assets/_files/en/our-methodology/methodology-specifications/m2ms-gas.pdf

¹¹⁰ In a partial equilibrium model feedback effects are excluded.

¹¹¹ LAI reviewed the RBAC RCI base case demand forecasts and other inputs for the study region.

Electric- and gas-side modeling was done iteratively until results converged, with GPCM providing locational gas pricing for Aurora modelling, which in turn provided GPCM with electric generator demand. GPCM’s PMI add-on uses a small amount of “blending” of previous iterations along with the most recent iteration in order to promote convergence. Convergence was determined to have been achieved when the change in prices from GPCM and the gas quantity delivered from Aurora was no more than 0.2% for a given year. Convergence was achieved in 3-4 iterations.

3.2 Gas Price Impact Results

The resulting price forecasts show marginal annual decreases in the study area indices of Transco Z4 and Transco Z5S when the SSE project is included. The similarity in pricing between the “with SSE” and “without SSE” cases is due to the simultaneous increase in both regional supply and demand for gas as an input for the new combined cycle plants served by SSE.

Figure 12 and Figure 13 show that, in terms of basis to Henry Hub, both Transco Z4 and Z5 South are relatively flat over the course of the study period. The average 2028-2031 prices for Transco Z4 in the “SSE” and “no SSE” cases are \$4.90/MMBtu and \$4.93/MMBtu, respectively. For Transco Z5 South, the average 2028-2031 prices are \$4.92/MMBtu and \$4.98/MMBtu, respectively. In both cases, the real price of delivered gas increases throughout the study period. This is consistent with GPCM’s projections of other major gas indices and is driven primarily by increasing LNG exports.

Figure 12: Transco Z4 Basis Annual Average (SSE vs. No SSE)

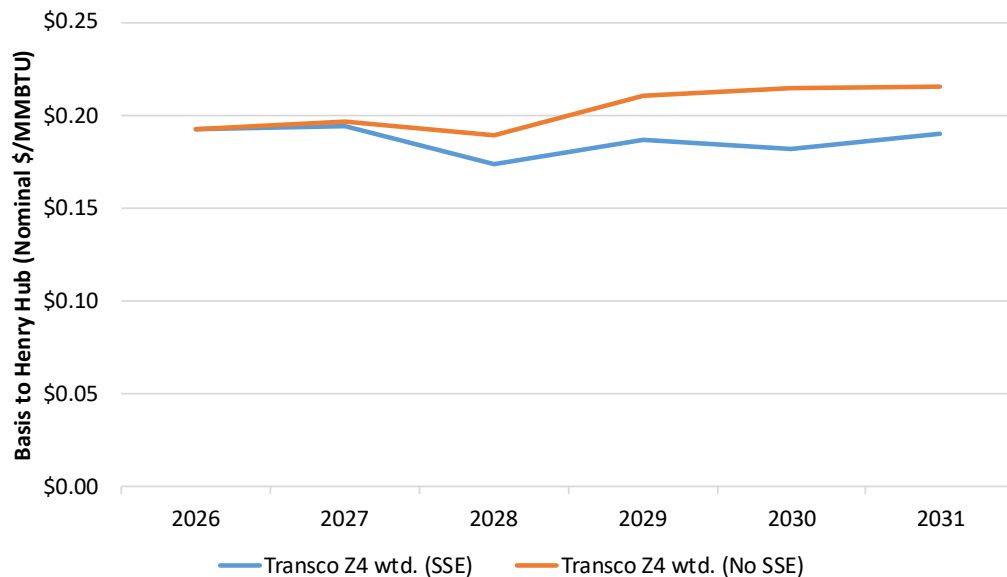


Figure 13: Transco Z5 South Basis Annual Average (SSE vs. No SSE)

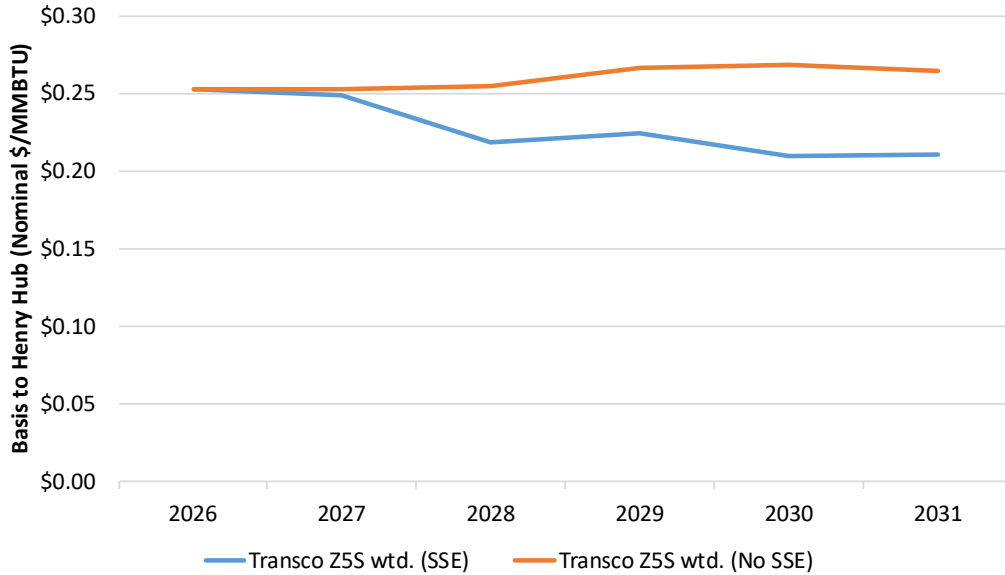
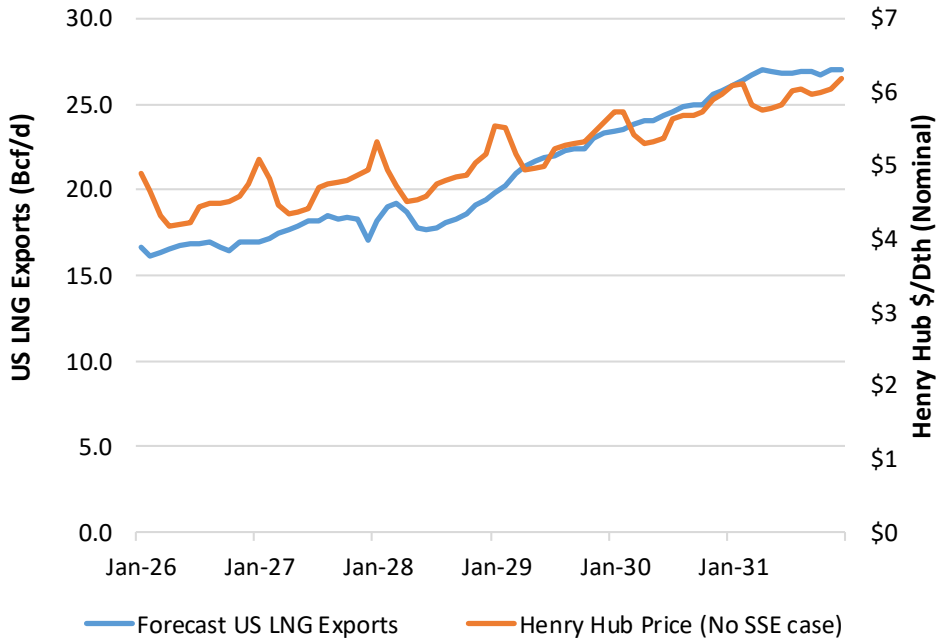


Figure 14 shows the relationship between Henry Hub and forecast LNG export capacity throughout the study period.

Figure 14: Forecast North American LNG Export Capacity vs. Henry Hub Real Price



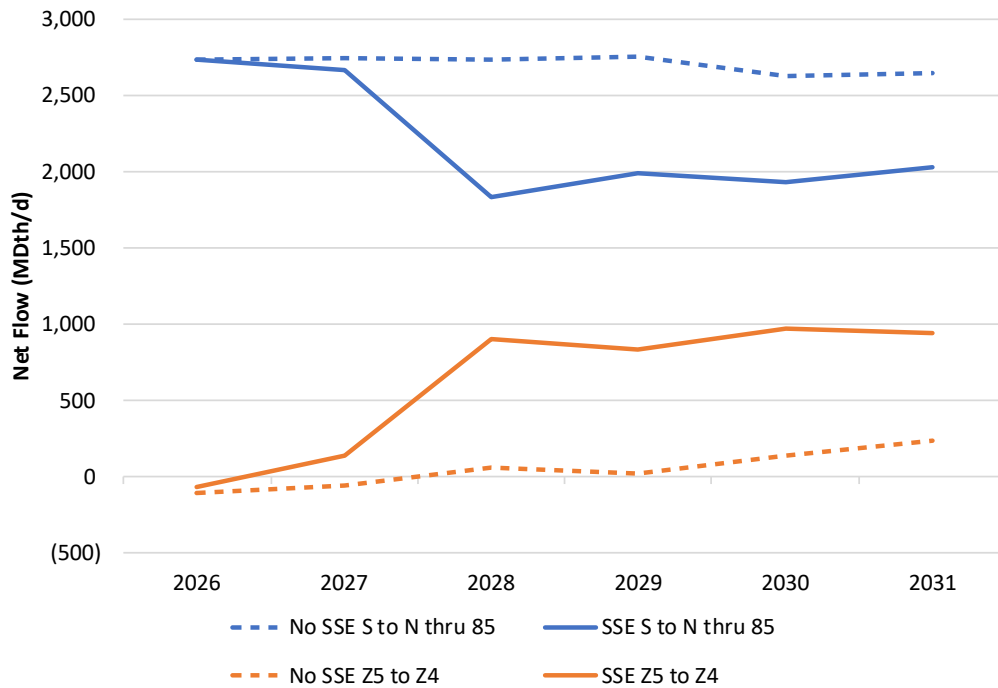
3.3 Flow Impact Results

As noted above, interstate pipeline infrastructure is represented in GPCM by a series of zones and links among them. In the SSE and NoSSE cases, LAI reviewed the forecast usage of interzonal

links which, in aggregate, represents pipeline flows across key Transco segments. LAI reviewed the net flows across two key points on Transco in the study region: Station 85, located in zone 4 in Alabama, and the Georgia-South Carolina state border which separates Zone 4 from Zone 5.

In the “SSE” case, annual average northbound flows through Station 85 (i.e. gas sourced from zones 0-3) are significantly lower than those of the “No SSE” case. This implies that the construction of SSE allows the study region to replace Gulf gas with Marcellus supplies. Figure 15 shows the steep drop-off of northbound flows through Station 85 in the “SSE” case after the postulated construction of SSE in November 2027.

Figure 15: Annual Average Transco Net Flows into the Study Region



The construction of SSE prompts a steep increase in southbound flows from Zone 5 to Zone 4. This flow dynamic implies the accelerated substitution of “conventional” northbound flows with supplies from Marcellus. Figure 15 compares net southbound flows in the “SSE” and “NoSSE” cases across the Georgia-South Carolina border. The negative flows in 2026 and 2027 imply that gas is initially flowing north from Zone 4 to Zone 5 on an average annual basis.

4 SSE Will Reduce Power Sector Emissions by Substitution of Natural Gas for Coal and Oil

This Section describes electric production cost modeling utilized to illustrate emissions reductions and avoided fuel costs attributable to SSE. LAI utilized Aurora, a production cost model licensed by Energy Exemplar, to forecast power market outcomes, including power plant dispatch patterns, power plant emissions, and natural gas demand for electric generation. LAI uses the default database provided by Energy Exemplar as a foundation for Aurora modeling. LAI then augmented Energy Exemplar's database with extensive customization based on public data sources, proprietary calculations, and professional judgment. LAI's Aurora analysis utilized a "but-for" comparison, where the inclusion of SSE is represented by an increase in natural gas available to electric generation and the inclusion of combined-cycle plants that will be supplied by SSE. Conversely, in the "without SSE" case less natural gas is available to electric generation and more coal generators must be retained to ensure that the shippers can maintain resource adequacy.

The analysis yielded the following key findings:

- Carbon emissions decreased by an average of 7.2 million short tons from 2028 to 2031 in the with SSE case from the no SSE case. The annual emissions impact increased over time as more combined-cycle additions were placed in service.
- The direct carbon emissions of the operations of SSE are about half a million short tons annually, which is far less than the annual impact on carbon emissions due to shifting power generation end use from coal to gas.
- Production costs decreased by an average of \$466 million from 2028 to 2031 in the with SSE case relative to the no SSE case. Savings increased as more combined-cycle plants were placed into service.
- A sensitivity with a daily volatility adjustment applied to gas prices on constrained winter days found that emissions and production cost benefits *increase* relative to the base case.
- A sensitivity with additional load growth and uprates to existing generation resources from the 2025 Georgia Power IRP applied to both cases found that emissions and production cost benefits *increase* relative to the base case.

The production cost analysis is not an exhaustive accounting of the benefits of SSE. The shippers and the region at large benefit from other impacts that have not been quantified in this report, including:

- Reduced life-cycle emissions upstream of the generator burner tip for coal transportation and mining;
- Improved health outcomes from reduced emissions;
- Economic development associated with lower energy costs, the construction of SSE, and new combined cycle generation; and

- Reliability benefits associated with transitioning from older coal units more prone to unplanned outages to new combined cycle units with high availability and better flexibility with respect to furnishing ancillary services.

Additional details on the formulation of modeling cases and shared assumptions follow.

4.1 Shared Base Case Assumptions

LAI’s assumptions represent “known and knowable” expectations based on utility IRPs. Information from the IRPs is supplemented with other publicly available planning documents. LAI modeled demand forecasts and generation resource additions outlined in utility IRPs and filled in gaps with SERC regional forecasts where IRPs were not available. SSE is slated to be placed into service in November 2027. The modeling horizon is set for 2027 through 2031, consistent with the in-service years for proposed combined cycle facilities (CCs) 1-3, which Duke has stated will have FT requirements satisfied by SSE.¹¹² Person County Energy Complex CC1 is expected to begin operation beginning of year 2029, while CC2 and CC3 are expected to be in service in 2030 and 2031. Subsequent years (2032 and beyond) were not modeled due to the increased uncertainty associated with a longer forecast period. Commitments that utilities make under IRP action plans become less firm over time, and assumptions regarding continued load growth, environmental regulations, and less mature generation technologies do not change the core findings incorporated in the Shippers’ respective IRPs.¹¹³ Duke also has not determined how to supply gas to two additional CC units 4 and 5 in subsequent future years.

Central to the IRPs is the view that load is growing at faster annual rates than in the recent past and that new gas-fired generation is needed to meet installed reserve margin requirements. Therefore, LAI used load and resource assumptions for Georgia Power from the 2023 IRP Update as the starting point for the base case because Georgia Power’s 2025 IRP has not yet been approved.

Study Region and Transmission Transfer Limits

LAI utilized Aurora in a zonal configuration with the study region modeled to include the SERC subregions that encompass all major SSE shippers’ service territories. The SERC East (aka VACAR South) subregion and SERC Southeast (also known as SOCO) subregion were modeled as zones with a transmission constraint between the two regions. This zonal configuration is consistent with Duke and Georgia Power’s operational practices, as each shipper participates in the Southeast Energy Exchange Market (SEEM). SEEM is an energy imbalance market that matches

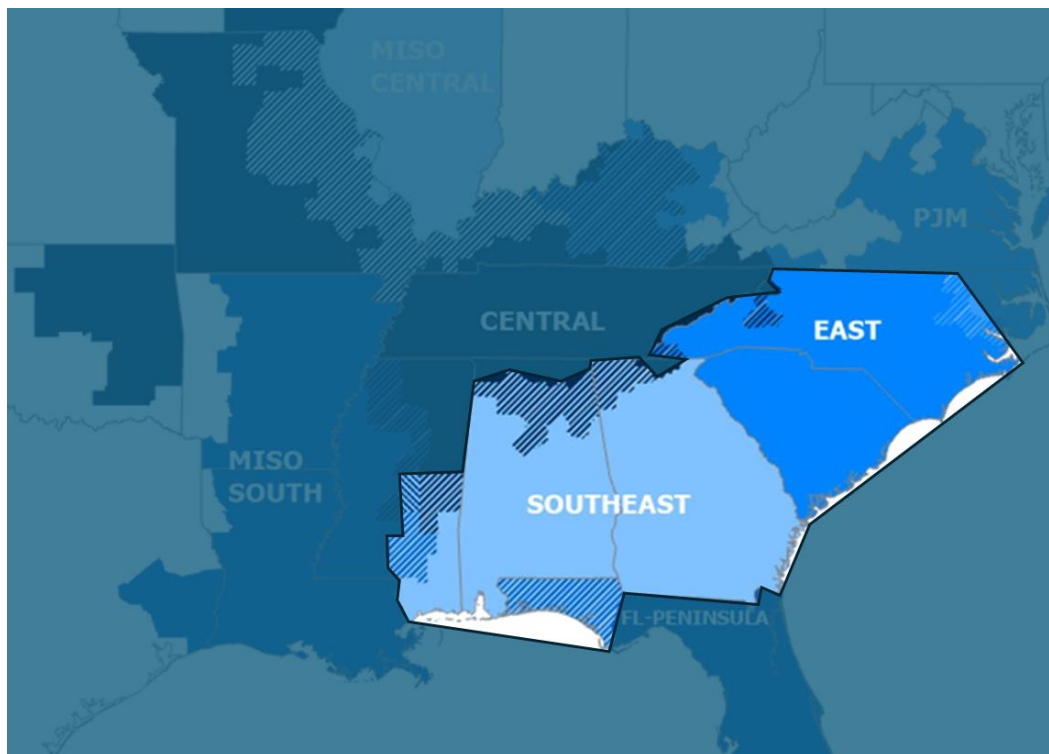
¹¹² See Rebuttal Testimony of Verderame and Mitchell, North Carolina PUC Docket No. E-11, Sub 190, page 11, line 3 through page 13, line 2.

¹¹³ Per 2025 IRP filing, Georgia Power performed nine scenarios in its capacity expansion model, assessing uncertainties in gas pressure, technology, load growth, and fuel prices. CC additions range from 2.7 to 5 GW by 2031. See Volume 2, 2025 IRP Resource Mix Study, page 3-4 and Capacity Expansion Plans for GPC.

Duke Energy Carolinas evaluated three core base portfolios considering factors like resource availability, natural gas supply, resource cost, fuel price, load, and energy efficiency. Duke provided the supplemental planning analysis filing with portfolio P3 recommendation. In the P3 portfolio, CC additions were projected to be 4.1 GW and CT additions were projected to be 2.1 GW in 2031. See Carolinas Resource Plan, Appendix C, Quantitative Analysis, page 79-81 Supplemental Planning Analysis Technical Appendix, Page 11-12

economic purchases and sales between members.¹¹⁴ The SERC Reliability Corporation does not define additional subregions within SERC East and SERC Southeast.

Figure 16: SSE Aurora Study Region¹¹⁵



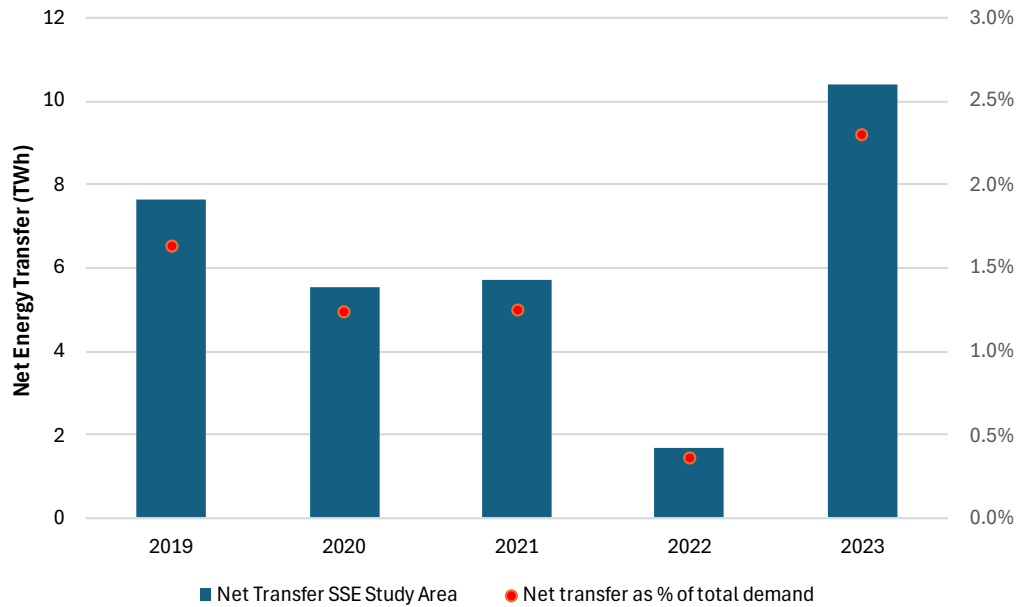
Boundary flows with other regions (including PJM, SERC Central/TVA, MISO South, and Florida) were modeled at zero MWh. LAI investigated historical EIA 930 transfer data to determine whether there is a significant influence of transfers with other regions on the study area. Since 2018, the SSE study region has been a net exporter, with net export ranging from 1.6 TWh to 10.4 TWh, or 0.4% to 2.3% of annual net demand.¹¹⁶ Therefore, modeling external transfers at zero flow has limited impacts on overall model results, and allows for more detailed focus on changes within the study region.

¹¹⁴ Southeast Energy Exchange Market, accessed March 25, 2025. <https://southeastenergymarket.com/>

¹¹⁵ 2023-2033 SERC Annual Long-Term Reliability Assessment Report, Page 9
https://www.serc1.org/docs/default-source/program-areas/reliability-assessment/reliability-assessments/2023-2033-serc-annual-long-term-reliability-assessment-report.pdf?sfvrsn=284f9dc2_10

¹¹⁶ EIA 930 reports transfers back to the second half of 2015, but does not report full-year consumed electricity until 2018. 2016 had slightly higher net export at 10.8 TWh. LAI determined the EIA 930 reported region of “SE” to be effectively the same as SERC Southeast, and the EIA 930 reported region of “CAR” to be effectively the same as SERC East.

Figure 17: Historical Net Energy Export from SSE Study Region



LAI used the results of Part 1 of the NERC Interregional Transfer Capability Study (ITCS) to define the transfer limits between SERC East and SERC Southeast during the study period.¹¹⁷

Table 18: SERC East to SERC Southeast Transfer Capabilities from NERC ITCS Part 1

Interface Direction	2024 Summer	2024/25 Winter
SERC Southeast -> SERC East	2,397 MW	3,669 MW
SERC East -> SERC Southeast	1,703 MW	3,536 MW

LAI compared the NERC ITCS limits to historical transfer data between SERC Southeast and SERC East (defined as “SE” and “CAR” in EIA 930, respectively). The ITCS summer transfer limits align well with historical transfer data for both Southeast to East and East to Southeast while the ITCS winter limits are higher than historical transfers for both directions. LAI derated the ITCS Winter transfer limits to match the highest observed historical transfers in each direction. The winter transfer limit from SERC Southeast to SERC East was derated from the ITCS value of 3,669 MW to the maximum observed historical value of 3,125 MW. The winter transfer limit from SERC East to SERC Southeast was derated from the ITCS value of 3,536 MW to the maximum observed historical value of 2,732 MW.

¹¹⁷ North American Electric Reliability Corporation, Interregional Transfer Capability Study (ITCS) Strengthening Reliability Through the Energy Transformation, Transfer Capability Analysis (Part 1), August 2024, page 48 https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf

Wheeling charges between the two regions were set based on Table 3-27 of the EPA's IPM modeling assumptions, at about \$8/MWh.¹¹⁸

Demand Forecast

LAI relied on utility IRPs, SERC Long-Term Reliability Assessments (LTRAs), the EIA's 2025 Annual Energy Outlook (AEO), and FERC 714 filing data as the basis for peak and annual energy forecasts. The SERC LTRAs provide summer and winter peak demand forecasts by SERC subregion, but do not provide annual energy forecasts or hourly demand profiles. Aurora requires three key inputs to model demand in an hourly production cost model: peak demand (MW), annual energy (MWh), and an hourly demand shape.

Peak Demand Forecast

LAI modeled both SERC East and SERC Southeast as winter peaking systems in the study horizon of 2027-2031. Both regions have historically shifted between summer and winter peaking based on weather. The LTRA historically considers SERC East a winter peaking system and considers SERC Southeast a dual-peaking system.

The SERC LTRA provides a peak forecast that aligns directly with the modeled regions in Aurora. However, the LTRA does not provide an annual energy forecast. Instead of relying on the 2024-2034 LTRA, LAI created a new peak demand forecast that blended individual utility IRP forecasts with 2023-2033 LTRA growth rates for utilities for which independent peak demand forecasts were unavailable. LAI's review indicated that larger utilities account for the bulk of demand growth, and that smaller utilities tend to have lower growth rates more in line with traditional end-uses of power. Figure 18 and Figure 19 show how this comparison yielded similar results to the 2024-2034 LTRA.

In SERC East, approximately 69% of the winter peak is made up of demand from Duke. In SERC Southeast, approximately 74% of the non-coincident winter peak in 2023 was made up of demand from Georgia Power, Alabama Power, and Mississippi Power, all of whom are served by Southern Company Services. The Georgia Power 2023 IRP Update, published October 2023, shows an annual winter peak growth rate of 5.5%.¹¹⁹

¹¹⁸ Documentation for 2023 Reference Case: EPA's Power Sector Modeling Platform Using IPM, U.S. Environmental Protection Agency, April 25, 2024, Accessed February 27, 2025. See Table 3-27.

<https://www.epa.gov/power-sector-modeling/documentation-2023-reference-case>

¹¹⁹ Georgia Power 2023 IRP update, p. 9. Available: <https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/2023-irp-update-main-document.pdf>

Table 19: Study Region Utility Winter Peak Forecast Rates

Region	Company	2023 Winter Peak (MW)	Percent of subregion	Source of Peak Forecast	Winter Peak Annual Growth Rate (23-31)
SERC Southeast	Alabama Power Company	11,385	28%	IRP	-0.55%
SERC Southeast	Georgia Power Company	14,227	35%	IRP	5.53%
SERC Southeast	Mississippi Power Company	2,057	5%	LTRA	0.58%
SERC Southeast	Municipal Electric Authority of Georgia	1,914	5%	LTRA	0.58%
SERC Southeast	Oglethorpe Power Corporation	8,378	21%	LTRA	0.58%
SERC Southeast	PowerSouth Energy Cooperative	1,916	5%	LTRA	0.58%
SERC Southeast	Southern Power Company	446	1%	LTRA	0.58%
SERC East/VACAR	Central Electric Power Cooperative Inc. - SC	4,036	9%	LTRA	0.58%
SERC East/VACAR	Dominion Energy South Carolina	4,124	9%	IRP	3.06%
SERC East/VACAR	Duke Energy Carolinas, LLC	18,690	43%	IRP	1.54%
SERC East/VACAR	Duke Energy Progress, LLC	12,230	28%	IRP	3.01%
SERC East/VACAR	South Carolina Public Service Authority	4,664	11%	IRP	2.96%

Figure 18 shows a comparison between the LTRA winter peak forecasts for SERC East and the LAI blended IRP forecast for the same region. The annual growth rate from 2024-2031 in the LTRA forecasts is 1.7%, whereas the annual growth rate in the blended forecasts is 2.4%. LAI’s forecast for SERC East winter peak is 2,343 MW higher than the LTRA forecasts in 2031.

Figure 18: SERC East LTRA and LAI's Blended IRP Winter Peak Forecasts

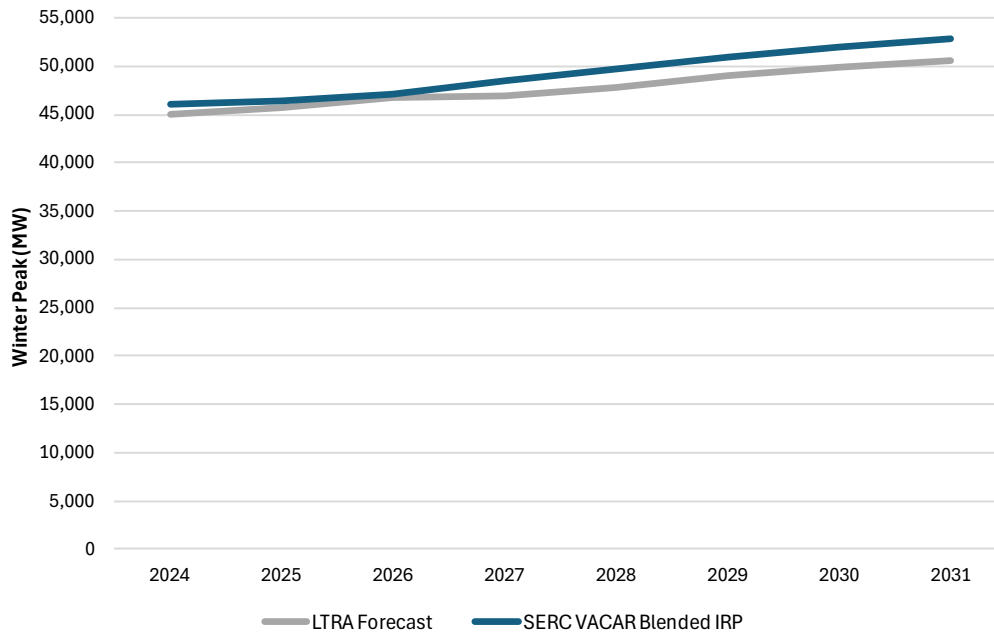


Figure 19: SERC Southeast LTRA and LAI's Blended IRP Winter Peak Forecasts

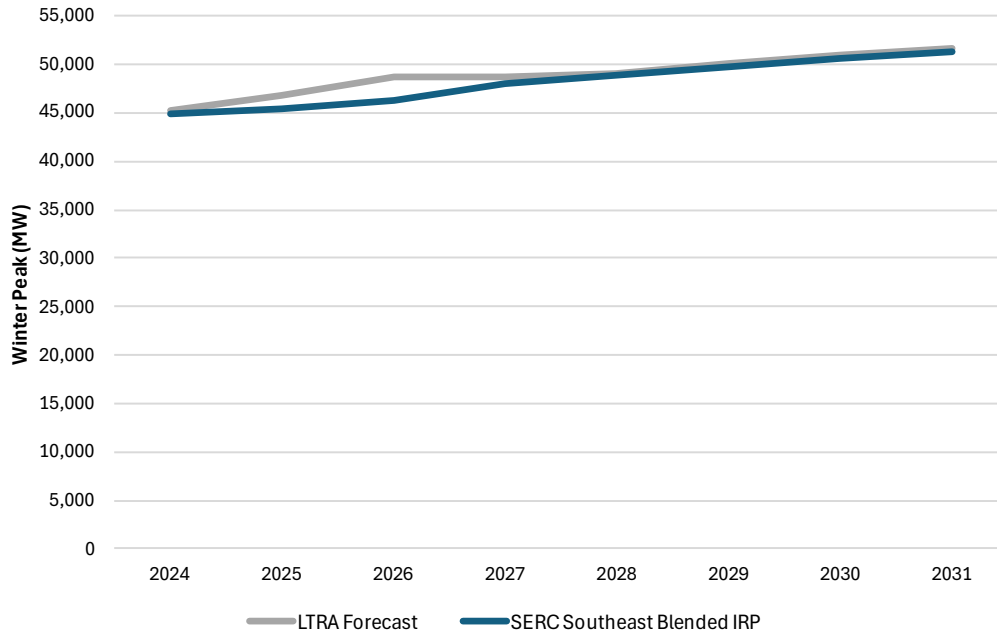


Figure 19 shows a comparison between the LTRA winter peak forecasts for SERC Southeast and the LAI blended IRP forecast for the same region. The annual growth rate from 2024-2031 in the LTRA forecasts is 1.9%, whereas the annual growth rate in the blended forecasts is 2.2%. LAI’s forecast for SERC Southeast winter peak is 367 MW less than the 2024 LTRA forecasts in 2031.

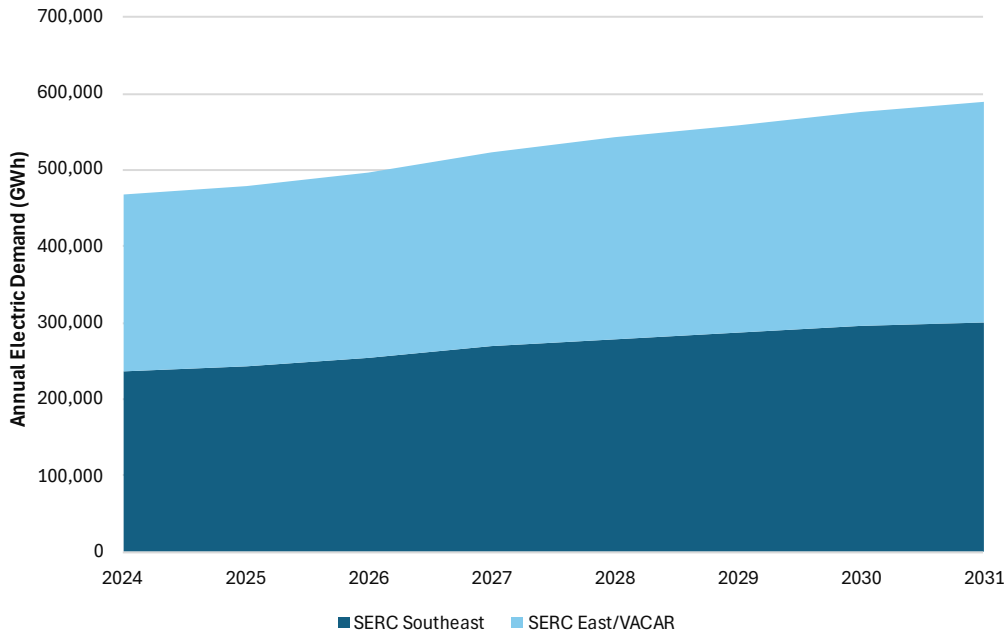
Energy Forecasts

Aurora requires an annual energy forecast for each modeled zone in addition to the annual peak. The Georgia Power Company, Dominion South Carolina, Duke Energy Progress, and Duke Energy Carolinas have IRPs with annual energy forecasts. For utilities without publicly available annual energy forecasts, LAI applied an annual growth rate to each utility’s reported 2023 annual energy. The annual growth rates of 0.88% applied to SERC Southeast and 0.92% to SERC East were calculated from the EIA 2025 AEO. Table 20 shows the annual growth rate for each member utility in the study regions.

Table 20: Study Region Utility Annual Energy Forecast Rates

Region	Company	2023 Annual Energy (GWh)	Source of Energy Forecast	Annual Growth Rate
SERC Southeast	Alabama Power Company	67,289	EIA AEO 2025 Table 54	0.88%
SERC Southeast	Georgia Power Company	87,603	IRP Update Technical Appendix p6	6.29%
SERC Southeast	Mississippi Power Company	13,188	EIA AEO 2025 Table 54	0.88%
SERC Southeast	Municipal Electric Authority of Georgia	12,139	EIA AEO 2025 Table 54	0.88%
SERC Southeast	Oglethorpe Power Corporation	42,290	EIA AEO 2025 Table 54	0.88%
SERC Southeast	PowerSouth Energy Cooperative	9,429	EIA AEO 2025 Table 54	0.88%
SERC Southeast	Southern Power Company	3,211	EIA AEO 2025 Table 54	0.88%
SERC East/VACAR	Central Electric Power Cooperative Inc. - SC	19,786	EIA AEO 2025 Table 54	0.92%
SERC East/VACAR	Dominion Energy South Carolina	22,936	Dominion SC 2024 IRP Update Table 11	2.22%
SERC East/VACAR	Duke Energy Carolinas, LLC	104,618	Duke IRP Supplemental Analysis Table SPA 2-8	1.94%
SERC East/VACAR	Duke Energy Progress, LLC	64,363	Duke IRP Supplemental Analysis Table SPA 2-9	2.37%
SERC East/VACAR	South Carolina Public Service Authority	26,153	2024 IRP Update Table 7	5.15%

Figure 20: SERC Southeast and SERC East Compiled Energy Forecasts 2024-2031



The annual average growth rate for winter peak from 2023 to 2031 is 2.35% for SERC Southeast and 2.51% for SERC East as compiled across all the surveyed utilities. The annual average growth rate for energy over the same period is 3.59% for SERC Southeast and 2.74% for SERC East.

Hourly Demand Shape

The source for hourly demand shapes is FERC Form 714 data.¹²⁰ LAI decided to use 2018 as the reference year for hourly demand shapes based on a review of the overall characteristics of the

¹²⁰ LAI sourced FERC Form 714 from S&P Capital IQ. It is also available on FERC’s web site:

<https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/data>

summer and winter peak patterns from 2012 to 2022, as well as data availability for renewable profiles sources. LAI compiled the 2018 hourly demand data from each member utility within SERC East and SERC Southeast to develop a single hourly profile for each region. Aurora uses these hourly demand profiles to scale the total demand in each hour for both SERC Southeast and SERC East modeled zones. The ultimate demand in each modeled zone is calculated as a result of the total annual energy, total peak demand, and the hourly profile. For consistency, variable energy resource profiles use the same reference year as the demand profile.

Fuel Price Forecast

Delivered fuel prices to generators are forecasted for natural gas, oil products, and coal. Nuclear generators are price takers and have virtually no dispatch flexibility. Nuclear fuel prices are ignored, as the Aurora model is configured so that nuclear plants run fully-loaded aside from scheduled refueling. Oil products were derived via a blend of EIA Short-Term Energy Outlook and AEO projections. LAI's delivered gas price forecasts were derived from the GPCM iterative modeling described in Section 3.2.

LAI reviewed 2023 EIA-923 survey fuel receipts data for all coal-fired generation within the study region. Delivered coal prices varied substantially, with the lowest plant fuel costs at \$2.19/MMBtu and the highest plant cost of \$6.876/MMBtu. Plant-specific costs vary based on the location of the production basis where coal comes from and the transportation route needed to get coal to the burner tip. LAI's review of futures prices for coal indicates that prices typically increase at or near the rate of inflation.

Emissions Allowance Prices

There is currently no carbon market in the Southeast region. However, pollutants such as Sulfur Dioxide (SO₂), and Nitrogen Oxides (NO_x) are regulated under the EPA's Cross-State Air Pollution Rule (CSAPR). North Carolina falls under SO₂ Group 1, which has stricter emission reduction requirements, while South Carolina, Georgia, and Alabama are part of SO₂ Group 2, facing less stringent limits.¹²¹ SO₂ pricing for Groups 1 and 2 is based on historical data from October 1, 2024, as sourced from S&P Capital IQ.

Under CSAPR states may be required to reduce annual emissions, emissions during the Ozone Season or both. North Carolina and South Carolina are covered solely by the CSAPR NO_x Annual program. Georgia is subject to both CSAPR NO_x Annual and CSAPR NO_x Ozone Season Group 2, which requires reductions in NO_x emissions during the ozone season, as mandated by the 1997 Ozone National Ambient Air Quality Standards (NAAQS). Alabama is covered by CSAPR NO_x Annual and CSAPR NO_x Ozone Season Group 3, which has additional reduction requirements for the ozone season under the 2008 Ozone NAAQS. NO_x pricing is based on the Proposed 2023-2042 System and Resource Outlook Emission Allowance Price Forecast, in unadjusted values.¹²² For

¹²¹ States that are Affected by the Cross-State Air Pollution Rule (CSAPR), EPA, Accessed October 1, 2024
<https://www.epa.gov/Cross-State-Air-Pollution/states-are-affected-cross-state-air-pollution-rule-csapr>

¹²² Economic Planning Process 2023-2042 System & Resource Outlook, NYISO, Page 19, September 21, 2023
https://www.nyiso.com/documents/20142/40143257/05a_09212023_ESPWG_2023-2042_Outlook_Update.pdf

states subject to both NO_x Annual and NO_x Ozone Season regulations, the total monthly NO_x price is calculated as the sum of the respective annual and ozone season prices.

Resource Additions and Retirements

LAI modified its resources database in Aurora using a variety of sources, including IRPs, data from EIA on planned and retired resources, and S&P Capital IQ. The base model includes EIA's planned resources, as well as projects under advanced development or construction from S&P Capital IQ. Duke Energy and Georgia Power have both outlined aggressive new supply-side resource additions to meet rising demand in the coming years, including the gas-fired generation discussed in Section 2.1. Both utilities also projected coal retirements in their IRPs. During the study period, other utilities plan to add 3.9 GW of gas-fired power capacity, with 90% expected to utilize CC technology and the remaining 10% utilizing CT.

Additions

Duke Energy has proposed adding 18 GW of new resources by 2035, as detailed in the Near-Term Actions Plan.¹²³ This aligns with the Core Portfolio P3 Base of the Resource Plan, which aims to develop and procure the resources necessary to facilitate the company's orderly transition to clean energy. The plan includes significant growth in natural gas, solar, solar-paired storage, and standalone storage with increasing durations. A large portion of the solar capacity, approximately 6,000 MW, is expected to come from the 2022-2025 Solar Procurement initiative, with the target to be achieved by 2031. Additionally, 2,700 MW of battery storage is planned, with 1,050 MW paired with solar. Duke also plans to bring online 2,175 MW of gas combustion turbines (CT) and 4,080 MW of CC gas plants by 2031. Onshore wind is expected to be part of new supply side additions starting with 300 MW in 2031.¹²⁴ The NCUC recently approved the CPCN for the 850 MW Marshall CTs, which have a combined capacity of 850 MW. These units function as a replacement for Marshall coal steam turbine units 1 and 2.¹²⁵

In the 2023 IRP, Georgia Power anticipated a significant increase in new resources to meet the aggressive load growth forecast. The projected capacity need for the winter of 2030/2031 has risen sharply, from around 3,700 MW in the 2022 IRP to as much as 8,500 MW, according to the updated 2023 IRP forecast.¹²⁶ To address this capacity requirement, Georgia Power is exploring multiple strategies to ensure system reliability and meet future demand.

¹²³ 2023 Carolinas Resource Plan, Chapter 4 Execution Plan, Table 4-2: Supply-Side Near-Term Actions Plan 2023 to 2026, page 10-11

<https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/chapter-4-execution-plan.pdf?rev=ccb35fc247e54eefbdcda2499a56764b>

¹²⁴ Additional capacity from pumped storage, nuclear SMRs, and offshore wind is not expected to be available by the end of the Study Period.

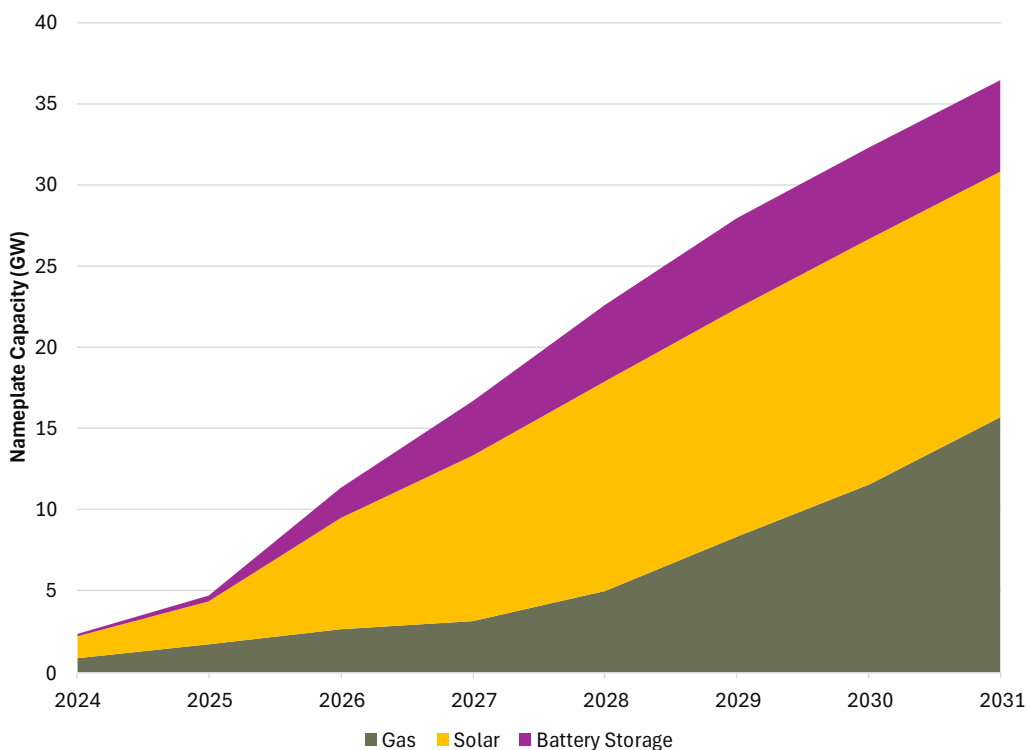
¹²⁵ Order Granting Certificate of Public Convenience and Necessity, filed December 2, 2024 in NCUC docket No. E-7, SUB 1297.

¹²⁶ 2023 Integrated Resource Plan Update, October 2023, page 10

<https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/2023-irp-update-main-document.pdf>

Georgia Power plans to utilize its current transmission interconnections to support newly proposed battery energy storage systems (BESS), which can help meet peak demands and improve system flexibility. Given the requirement to maintain at least 70% ownership of its incremental capacity,¹²⁷ Georgia Power continues to develop its own assets, particularly utility-scale solar, battery storage, and gas. Georgia Power has proposed the development, ownership, and operation of up to 1,400 MW of capacity from three simple cycle combustion turbine resources at Plant Yates, which are expected to come online by late 2026 or early 2027.¹²⁸ The GA PSC unanimously voted to approve Yates 8-10 on August 20, 2024.¹²⁹

Figure 21: Planned Resource Additions in the Study Footprint¹³⁰



Retirements

Similar to resource additions, LAI verified resource retirement dates using sources including IRPs, EIA-860 survey data, S&P Capital IQ, and news reports.

¹²⁷ *id.*, page 19

¹²⁸ *id.*, page 21

¹²⁹ Ga. regulators approve Georgia Power gas plant addition prompted by demand surge, Abbie Bennett of S&P Commodity Insights. Wednesday August 21, 2024.

¹³⁰ Duke Energy is expected to add the first land-based wind project to the study region, bringing 300 MW of capacity online in 2031.

Duke Energy conducted thorough analyses of coal retirements in their IRPs. Duke Energy operates 15 coal units, with all portfolio analyses pointing to a complete exit from coal-fueled generation by 2035, retiring over 8,400 MW of coal capacity. Allen Units 1 and 5 retired in 2024. Cliffside Unit 6, which will operate exclusively on natural gas after 2035, was excluded from the coal retirement analysis in the Carolinas Resource Plan. The retirement schedule for Roxboro was updated, with both Units 1 and 4 now planned for retirement. The transmission capacity from these retirements will support a Generator Replacement Request for Person County CC 1.¹³¹ The EPA Clean Air Act Section 111 Final Rule, which may require significant emissions reductions, could accelerate coal retirements or necessitate conversions to cleaner energy sources by 2032. Nuclear energy remains central to the companies' long-term strategy, providing over 10,000 MW of zero-carbon power. Securing federal approval for 20-year Subsequent License Renewals is a critical pathway to meet capacity needs, with all nuclear units expected to apply by 2035.¹³²

In Georgia Power's 2022 IRP Final Order, the Commission required a reassessment of the retirement schedule for Plant Bowen Units 1-2 in the 2025 IRP, with the potential to extend their operations until 2035.

Table 21: Planned Resource Retirements in the Study Footprint¹³³

Plant Name	Utility	Nameplate Capacity (MW)	Cumu. Capacity (MW)	Fuel	Area	Retirement Year
G G Allen 1 & 5	Duke Energy	435	435	Coal	VACAR	2025
Victor J Daniel Jr 1 & 2	Mississippi Power	1,097	1,532	Coal	Southeast	2027
John S Rainey 2A & 2B	South Carolina Public Service Authority	330	1,862	Gas	VACAR	2027
Gaston 1-4	Alabama Power	1,517	3,378	Gas	Southeast	2028
Wateree Station 1&2	Dominion Energy South Carolina	772	4,150	Coal	VACAR	2028
Marshall 1 & 2	Duke Energy	697	4,847	Coal	VACAR	2029
Roxboro 1 & 4	Duke Energy	1,156	6,003	Coal	VACAR	2029
Winyah 1-4	South Carolina Public Service Authority	1,260	7,263	Coal	VACAR	2030
Williams	Dominion Energy South Carolina	660	7,923	Coal	VACAR	2030
Cliffside 5	Duke Energy	621	8,544	Coal	VACAR	2031
Mayo	Duke Energy	763	9,307	Coal	VACAR	2031
Marshall 3 & 4	Duke Energy	1,422	10,729	Coal	VACAR	2032
Hilton Head 1-3	South Carolina Public Service Authority	118	10,847	Oil	VACAR	2033
Roxboro 2 & 3	Duke Energy	1,439	12,286	Coal	VACAR	2034
Gaston 5	Alabama Power	952	13,238	Gas	Southeast	2035
Bowen 1-2	Georgia Power	1,595	14,833	Coal	Southeast	2035
Scherer 3	Georgia Power	891	15,724	Coal	Southeast	2035

New Generation Operating Parameters

For renewable additions, particularly solar and wind, the output profile was calculated based on 2018 weather data, consistent with the weather year used for demand profiles. Solar generation

¹³¹ Supplemental Planning Analysis, Table SPA 3-1: Coal Unit Retirements (effective by January 1 of year shown), page 34.

<https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/supplements/supplemental-planning-analysis.pdf?rev=f134d62ba6d645ccb3de2bc227a0d42d>

¹³² *Id.*, page 15

¹³³ Tabulated units are greater than 25 MW. Retirements are effective at the beginning of the listed year.

was modeled using the NREL System Advisor Model tool for major representative airports within the study area, with projects mapped to the nearest airports in the state. Wind resources were modeled based on specific project locations, with adjustments made for losses according to the project's configuration. For new gas additions, LAI verified thermal operating parameters using public filings for CPCNs, EIA modeling assumptions¹³⁴, and the PJM CONE Study¹³⁵ to establish generic parameters such as heat rate, emissions rates, and minimum load.

4.2 But-For Excursions

For purposes of comparing the emissions and production (namely fuel) cost benefits that SSE enables in terms of electric dispatch, LAI started with baseline assumptions that include generating resource additions and retirements that are consistent with shippers' IRPs. These baseline resource expansion assumptions were maintained in the "with SSE" case. Conversely, in the "no SSE" case, combined-cycle additions were removed from the resource mix and other resources are utilized to maintain resource adequacy instead. Additionally, daily gas consumption constraints that were defined for the SERC East and Southeast regions were increased to account for deliverable quantities on SSE in the "with SSE" case, while daily gas available to generators remains lower in the "no SSE" case. Details on the differences in the but-for cases follows.

Resource Mix Changes

In the "No SSE" case, LAI assumed that Duke is unable to build CCs 1-3 without the SSE Project as a source of FT. In that case, coal retirements that were posited in Duke's Coal Retirement Analysis would be deferred until after the study period. LAI assumed that Roxboro 1 and 4 would remain in operation, as the transmission facilities associated with these plants would no longer be dedicated to CC1. Additionally, LAI expects that the Marshall 1 and 2 units which retire in 2029, and the Mayo 1 and Cliffside 5 units that retire in 2031, would instead remain in operation through 2031. These units total approximately 2,109 MW in winter capacity, compared to 2,720 MW of new capacity that is provided by CCs 2 and 3. Given that the deferred coal retirements are less than the unbuilt CC additions, an additional 425 MW CT was added in 2031 to ensure that Duke remained above the 22% winter reserve margin threshold.

As Georgia Power has noted in discussions and via the public record, the Company has several options for how to deploy FT. For example, Georgia Power can support new generators selected in the All-Source RFP (whether owned by the company or a third party), firm up supply for steam turbines that are currently running on oil and gas, or repower coal generation to gas. IRP modeling conducted by Georgia Power suggests that combined-cycle units will be a critical part of a future supply portfolio. The All-Source RFP identifies FT requirements for CCs, where "Each CC Facility will be evaluated with sufficient firm gas transportation to allow 14 hours of operation at full load plus 10 hours operation at peaking or secondary modes of operation (24 hours total

¹³⁴ Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies, Table 1-2 — Cost & Performance Summary Table, EIA, January 2024, page III

https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

¹³⁵ PJM CONE Study, Brattle Group, April 21, 2022

<https://www.brattle.com/wp-content/uploads/2022/05/PJM-CONE-2026-27-Report.pdf>

operation). In each CC Submission, Participant must indicate the permitted hours of operation.”¹³⁶

With some simplifying assumptions, LAI estimated the amount of new CC generation that the incremental 400 MDth/d contracted by Southern Company Services from the SSE project can support. LAI interpreted secondary modes of operation to represent load following and part-load operations equivalent to 5 hours at full load, for a total of 19 hours of full load estimated. LAI assumes a 7,000 Btu/kWh heat rate, which is rounded up from estimated full-load heat rate for new build to reflect lower efficiency during load-following.¹³⁷ LAI estimated that about 3,000 MW of combined-cycle capacity could be supported by 400 MDth/d of FT. Therefore, in the “with SSE” case, one 1,000 MW CC plant is added in each of the years identified in the All-Source RFP (2029-2031).

LAI did not postulate any incremental coal retirements for Georgia Power in the “No SSE” case. LAI assumed that the Gaston units will retire rather than have their life span extended without new firm gas transportation, in part based on commentary from the 2022 IRP:

Plant Gaston Units 1-4 are steam resources located in Alabama. These units operate primarily on natural gas while maintaining limited coal backup per the requirement of the Mercury and Air Toxics Standards rule to ensure reliable operation during periods when natural gas pipelines are constrained, such as during cold winter days. The ability to maintain coal backup is impacted by the requirements of the ELG rule. This impact would likely require the Company to eliminate coal backup and make long-term investments in expensive annual firm gas transportation to ensure reliable operation and avoid installation of ELG controls. Given the age and declining economics of these resources, it is not cost-effective to invest in their long-term operation and the associated annual firm gas transportation.¹³⁸

In the “No SSE” case, LAI expects that no FT is available to replace coal backup that cannot meet environmental restrictions. Hence, the units would not count toward meeting winter reliability requirements and would therefore retire in both cases. Therefore, alternative resources without FT entitlements would be needed. Absent the FT from SSE, LAI assumed that the same amount of nameplate capacity would be obtained from combustion turbines with backup fuel (provided it is available in both winter and summer seasons) and 4-hour batteries. For simplicity LAI assumed a 50/50 split between these two technologies.

Gas Constraint

LAI structured daily gas burn constraints that limit the amount of gas available in a given modeled day. There are two gas constraints postulated that match the SSE project footprint. While a portion of the Aurora study region includes generation that takes gas upstream of Station 85 in eastern Mississippi, FT entitlements are typically centered around the Station 85 pooling point. Gulf receipts and large industrial demands on Sabal Trail, as well as storage on the segments

¹³⁶ Georgia Power All Source RFP Section 3.10.1.B.

¹³⁷ PJM CONE 2026/2027 Report, Prepared for PJM Interconnection by The Brattle Group and Sargent & Lundy, April 21, 2022. See page v. <https://www.brattle.com/wp-content/uploads/2022/05/PJM-CONE-2026-27-Report.pdf>

¹³⁸ 2022 Integrated Resource Plan, filed in Georgia Public Service Commission Docket 44160. See page 11-74.

upstream of Station 85, make defining a daily constraint for this section of pipeline infrastructure more difficult. Conversely, north to south flows should be constrained based on what can be moved across the Virginia / North Carolina state border to get supplies from Marcellus into the study region. LAI has further segmented the constraint for Zones 4 and 5, respectively.

Pipeline Capacity

A review of FT entitlements was conducted to identify the pipeline capacity deliverable into each control area. Shippers were categorized by whether they are large utilities, municipal utilities, industrials, producers, marketers, etc. South to North FT entitlements include contracts that have primary receipt points at or upstream of Station 85. Deliveries to points in Zones 4A and 4B are not included. North to south FT entitlements include contracts that have primary receipt points in Z6 or VA and span the VA/NC border. Contracts that traverse the entirety of the control area, though their primary receipt and delivery points lie outside of the control area (e.g. a contract with a primary receipt point in Virginia and primary delivery points in Louisiana), are included in the analysis if the shipper is either a producer, marketer, or end-user within the control area. Contracts traversing the study area are not included in the constraint if the shipper is an end-user outside of the control area.

Figure 22: Transco FT Entitlements S to N Thru Station 85

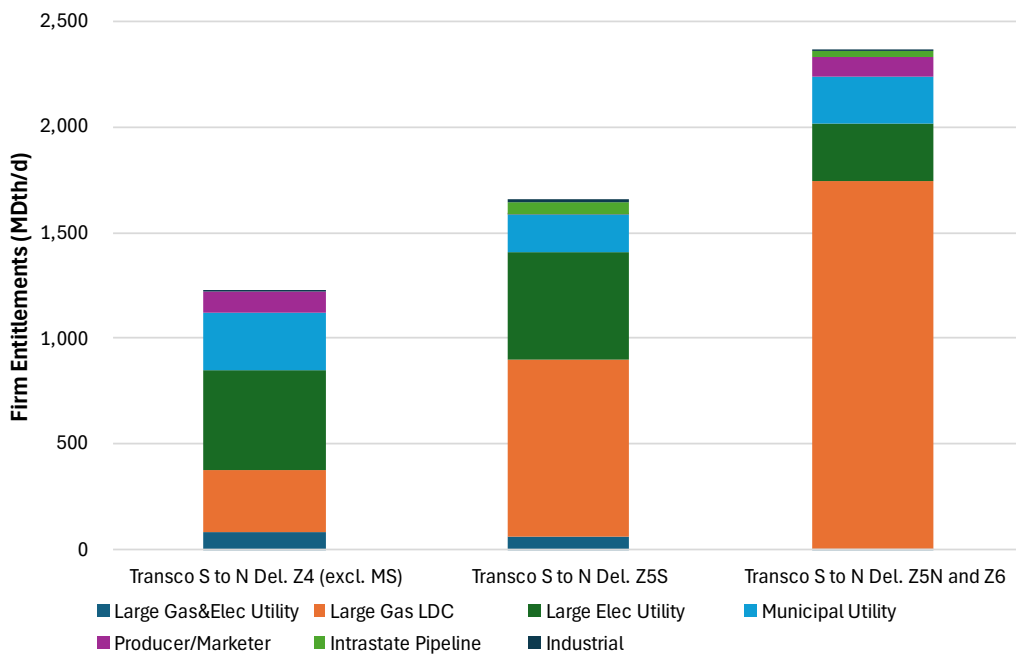
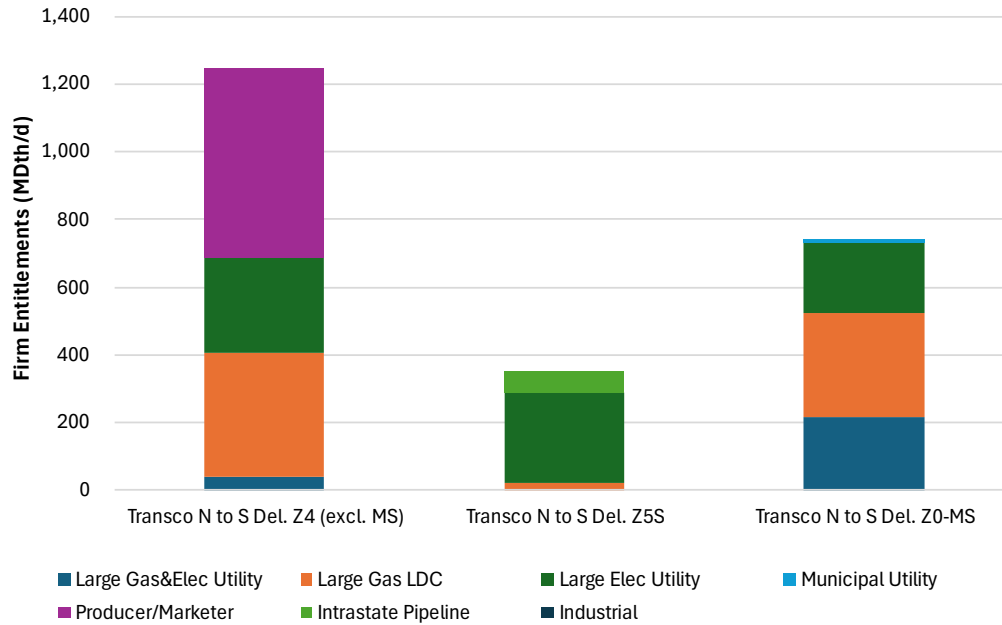


Figure 23: Transco FT Entitlements N to S across VA/NC Border



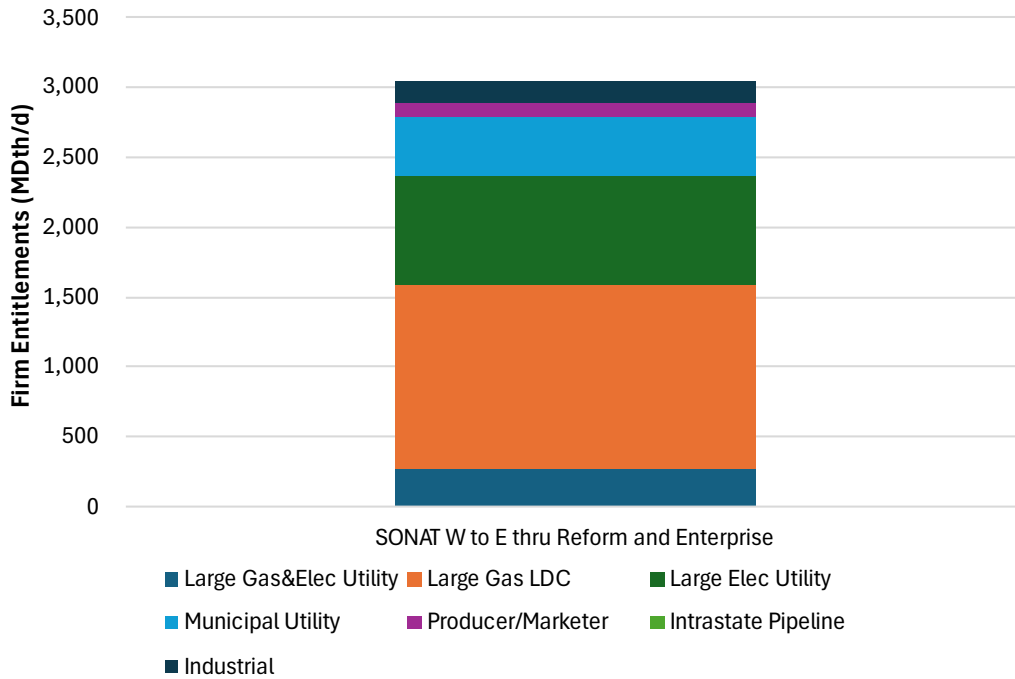
In total, a maximum of 5,374 MDth/d of Transco FT is assumed to be available to the control area. Large electric utilities account for 1,896 MDth/d of Transco FT deliverable into the control area, with Duke Progress/Carolinas accounting for 448 MDth/d and Southern Company Services accounting for 745 MDth/d.

Southern Company and other utilities in the SOCO subregion also receive gas from SNG. As discussed in Section 2.7, SNG is already working with Southern Services and other shippers on SNG SSE4, a 1,323 MDth/d expansion on the main line that would reach all the way to the east end in South Carolina. The project is on a similar development track to SSE. SNG has recently started the process for FERC certification.¹³⁹ The project is mainly comprised of upgrades on the southern main line starting at the Enterprise compressor station. Concurrently, Kinder Morgan has also entered pre-filing for the Mississippi Crossing (MSX) project, which would add capacity to SNG’s interconnections with other pipelines.¹⁴⁰ LAI defined the SNG constraint control area for deliveries downstream of the Enterprise and Reform compressor stations. SNG lists the Enterprise and Reform compressor stations prominently on its segment capacity map, and these two stations are near the Zone 1-2 border which is a solid point for comparison to the affected area of SSE expansion. Additionally, there are many interconnects with other pipelines upstream of these stations, which makes it difficult to delineate a control area for purposes of setting the daily gas constraint.

¹³⁹ FERC, “Southern Natural Gas Company, L.L.C., et al. submit request to implement pre-filing review process re the proposed South System Expansion 4 Project under PF25-1,” October 30, 2024. https://elibrary.ferc.gov/eLibrary/docinfo?accession_num=20241031-5065

¹⁴⁰ SNG SSE4 and MSX are not included in the shared assumptions for GPCM and the Aurora gas constraint. These projects are at a similar development state as SSE, and less information has been shared about the shippers and contract paths thus far in the pre-filing process.

Figure 24: SNG FT Entitlements West to East across Enterprise and Reform



Using these parameters, the total SNG FT deliverable to the control area is 3,051 MDth/d. Large electric utilities account for 1,053 MDth/d of SNG FT deliverable into the study areas, with Southern Company Services accounting for 781 MDth/d.

Non-Power Gas Demand Regression

LAI estimated how much gas was scheduled by non-power gas users including residential, commercial, and industrial (RCI) end users. The RCI gas demand regression models were developed separately for winter and summer, as demand is fundamentally driven by different factors in each season. Winter is defined as October through March, with the peak winter period spanning December to February. Summer is defined as April through September. Both seasonal models were based on multivariate regression and are trained using data from 2019 to February 2024. Historical daily RCI demand data was sourced from scheduled flow data for Intraday 3 cycles for Transco and SNG as scraped from the pipeline EBBs by S&P Capital IQ. For Carolina Gas Intraday 3 data is unavailable, so Intraday 1 is used as a substitute. The scheduled flow data was retrieved for states within the study region, including SERC East (North Carolina, South Carolina) and SERC Southeast (Alabama, Georgia). To validate the accuracy of scheduled flow data, LAI compared scheduled flows against EIA-reported RCI gas consumption. The analysis confirms that the annual scheduled flows align well with actual consumption. The EIA values shown in the graphs below represent daily average derived from monthly RCI gas consumption. RCI and power plant gas demand are derived from Scheduled Flow data from S&P Capital IQ.

Figure 25: SERC East Historical Scheduled Flow vs. EIA Gas Consumption

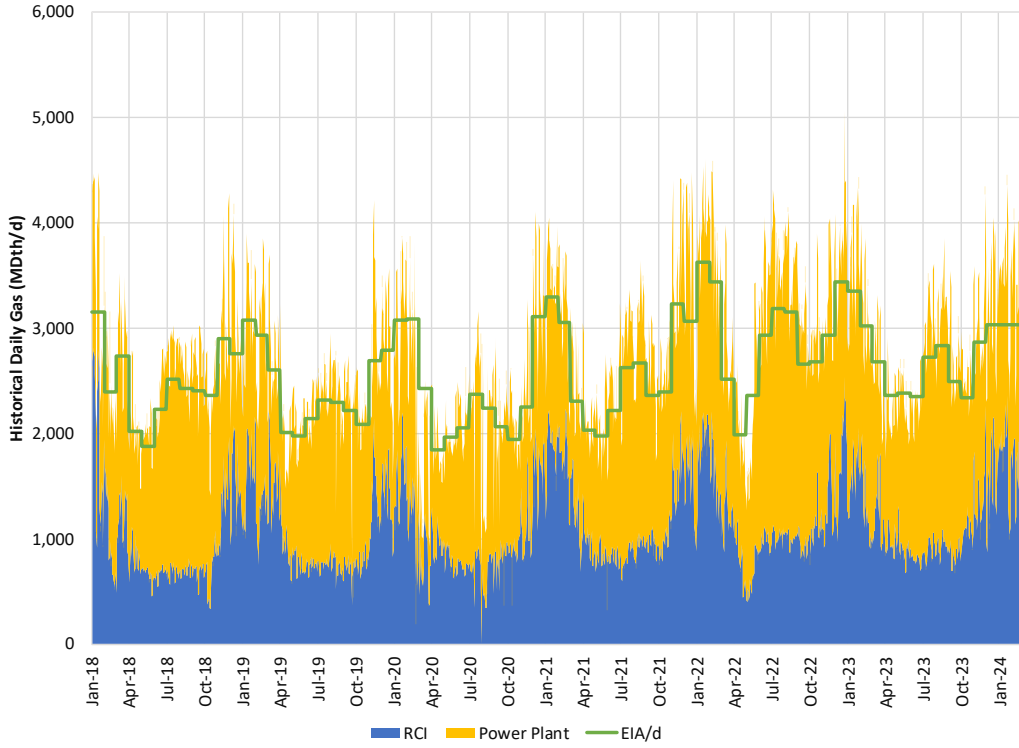
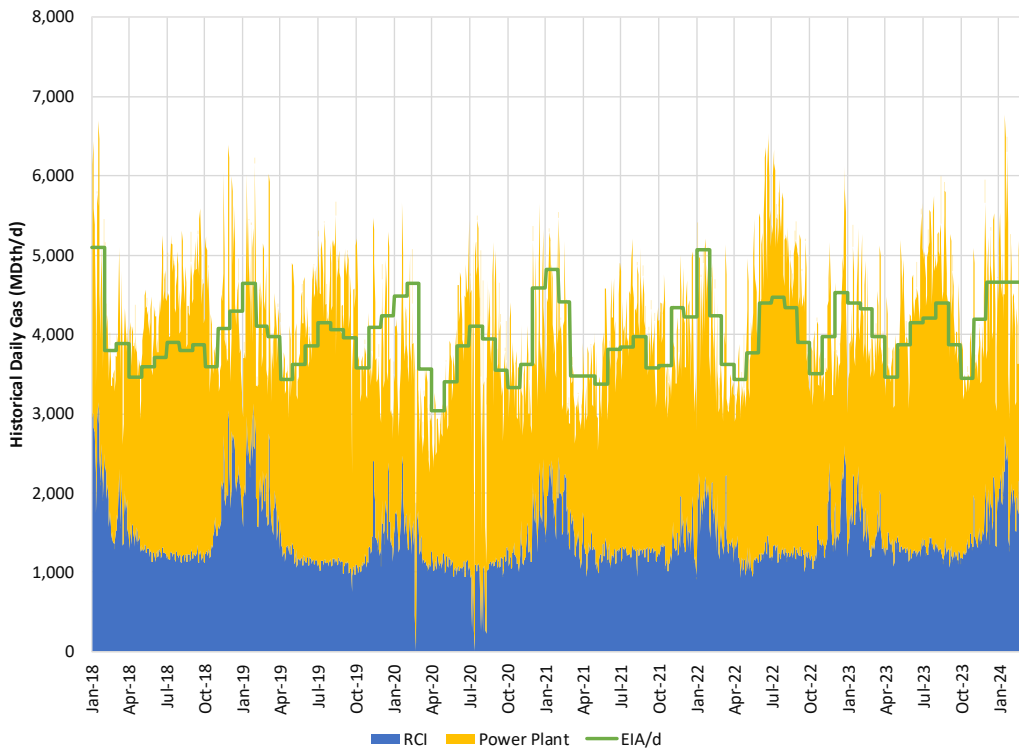


Figure 26: SERC Southeast Historical Scheduled Flow vs. EIA Gas Consumption



The winter model is primarily driven by heating degree days (HDD), incorporating feature engineering techniques such as the quadratic term of HDD and daily variations to capture the nonlinear relationship between inputs and outputs. Additional factors include weekday versus weekend effects, peak winter versus shoulder months, and annual growth trends represented through dummy variables to establish a more accurate relationship with RCI demand.

$$\text{Winter Gas Demand} = \beta_0 + \beta_1 \times \text{HDD} + \beta_2 \times \text{HDD}^2 + \beta_3 \times \text{HDD Diff} + \sum_i \beta_i \times X_i$$

where X_i represents binary variables: Weekend, Core Winter, and Winter Year Dummies (2019/20 to 2023/24)

Winter Variable Descriptions:

- Gas Demand (MDth per day) – Dependent variable representing natural gas demand.
- Intercept (β_0) – Baseline gas demand when all other variables are zero.
- HDD (°F) – Measure of heating demand based on temperature.
- HDD² (°F²) – Captures nonlinear effects of heating demand.
- HDD Diff (°F) – Day-over-day change in HDD, accounting for sudden temperature shifts.
- Weekend (Binary: 0 or 1) – Indicates whether the day is a weekend (1) or not (0).
- Core Winter (Binary: 0 or 1) – Assigned 1 if the day falls within the core winter months (December, January, and February) and 0 if it falls in the non-core winter months (March, October, and November).
- Winter Year Dummies (Binary: 0 or 1) – Individual dummies for each winter season from 2019-20 to 2023-24, capturing growth over time.

Table 22: Winter Regression Model Coefficients

State	AL	GA	NC	SC
β_0	713.9	876.0	327.6	496.1
β_1	(0.3)	21.1	27.2	7.7
β_2	0.3	0.3	(0.0)	0.2
β_3	(4.0)	(6.8)	(8.4)	(1.1)
$\beta_{weekend}$	(17.5)	(65.9)	(83.8)	(23.0)
$\beta_{core\ winter}$	53.4	42.5	55.0	(2.4)
β_{w19}	(88.2)	(424.6)	(7.3)	(34.2)
β_{w20}	3.5	(389.1)	111.4	(40.3)
β_{w21}	(146.7)	(304.3)	131.3	36.2
β_{w22}	(34.7)	(306.7)	161.2	(23.6)
β_{w23}	(29.1)	(262.8)	193.9	(30.2)

AL and GA have the highest baseline gas demand, indicating that, under similar conditions, they experience higher default gas consumption compared to NC and SC. The core winter variable is a key factor driving increased gas demand in AL, GA, and NC. HDD significantly influences gas demand in NC and GA but has less impact elsewhere, suggesting that gas demand is more dependent on other factors rather than just temperature.

In contrast, the summer model is driven by industrial activity, with some contribution from air-conditioning demand use in large commercial and industrial facilities. The input variables are cooling degree days (CDD) and maximum temperature, with quadratic terms and daily variations applied to capture nonlinear effects. The model also accounts for weekday versus weekend patterns, holiday versus non-holiday effects (including long weekends), and an industrial production index to reflect industrial activity, particularly considering downtime during the COVID-19 period in 2020. Annual growth trends are incorporated through dummy variables to track changes over the modeling period.

$$\text{Summer Gas Demand} = \beta_0 + \beta_1 \times CDD + \beta_2 \times CDD^2 + \beta_3 \times CDD \text{ Diff} + \beta_4 \times \text{Max Temp} + \beta_5 \times \text{Max Temp}^2 + \beta_6 \times \text{Max Temp Diff} + \beta_7 \times IPI + \sum_i \beta_i \times X_i$$

where X_i represents binary variables: Weekend, Holiday, and Summer Year Dummies (2020 to 2023).

Summer Variable Descriptions:

- Gas Demand (MDth per day) – Dependent variable representing natural gas demand.
- Intercept (β_0) – Baseline gas demand when all other variables are zero.
- CDD (°F) – Measure of cooling demand based on temperature.
- CDD² (°F²) – Captures nonlinear effects of cooling demand.
- CDD Diff (°F) – Day-over-day change in CDD, accounting for sudden temperature shifts.
- Max Temp (°F) – Highest temperature recorded in a day.
- Max Temp² (°F²) – Captures nonlinear effects of maximum temperature.
- Max Temp Diff (°F) – Day-over-day change in max temperature.
- Industrial Production Index (IPI) (Index Value, unitless) – Measure of industrial activity affecting gas demand, especially during Covid-19 period.
- Weekend (Binary: 0 or 1) – Indicates whether the day is a weekend (1) or not (0).
- Holiday (Binary: 0 or 1) – Indicates whether the day is a public holiday (1) or not (0).
- Summer Year Dummies (Binary: 0 or 1) – Individual dummies for each summer season from 2020 to 2023, capturing growth over time.

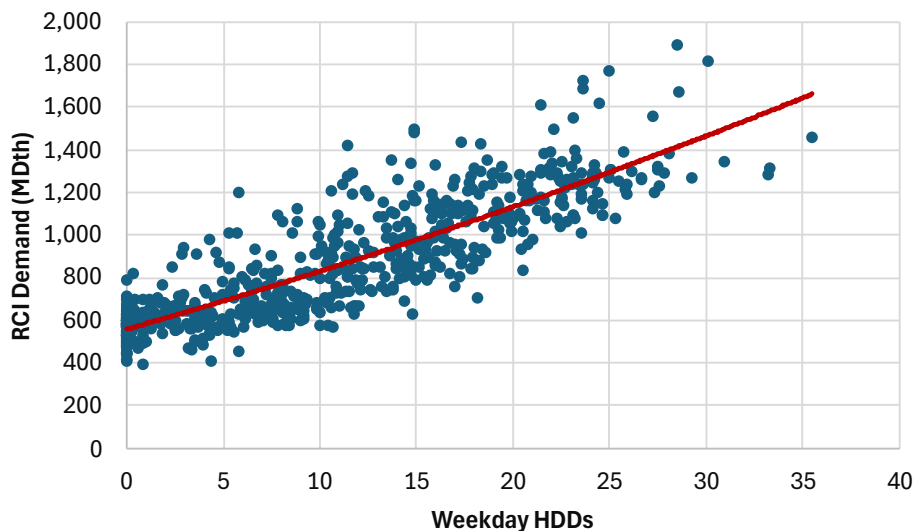
Table 23: Summer Regression Model Coefficients

State	AL	GA	NC	SC
β_0	745.3	2,532.7	2,586.2	2,246.3
β_1	2.8	(0.2)	(10.6)	5.5
β_2	0.0	0.1	0.4	(0.1)
β_3	(2.5)	(1.3)	3.0	(3.6)
β_4	1.0	(45.9)	(46.6)	(44.1)
β_5	(0.0)	0.2	0.3	0.3
β_6	0.7	3.0	1.1	1.2
β_7	(1.7)	1.3	(2.7)	1.1
$\beta_{weekend}$	(11.6)	(60.0)	(41.7)	(26.4)
$\beta_{holiday}$	(2.6)	(87.6)	(37.8)	(41.0)
β_{s20}	(42.0)	(31.8)	19.7	2.9
β_{s21}	113.5	(1.2)	116.3	11.2
β_{s22}	68.4	16.8	169.4	10.2
β_{s23}	130.4	6.9	104.9	13.8

In summer, the default gas consumption is highest in GA, SC, and NC. Maximum temperature typically reduces gas consumption, with higher temperatures leading to a decrease in demand in these states. The weekend and holiday effects consistently reduce gas demand across all four states. Over the years, gas demand during summer has grown, with certain years, such as Summer 2022 and Summer 2023, showing notable increases in demand, especially in NC and AL.

Once the model was developed, the 2018 specific inputs were applied to estimate RCI demand, aligning with the modeled weather year for electric simulations in Aurora. A monthly adjustment factor was applied to calibrate the predicted values to recent growth rates in 2024 based on actual RCI demand.

Figure 27: GA Winter Relationship Demonstration



Constraint Calculation

To estimate gas constraints for power generation, the predicted RCI demand, derived from the regression model, was subtracted from the total FT capacity to determine the remaining pipeline capacity available for electric power generation.

Since January 2018 includes cold winter weather RCI demand was high, leaving limited capacity for power generation under the modeled regression. Real-life outcomes suggest that during cold weather conditions some surplus deliverability can be made available to meet demand, perhaps because weather patterns in the Northeast were milder and some capacity from other customers can be repurposed for SERC East and Southeast. LAI established a minimum threshold based on the Maximum Daily Quantity (MDQ) allocated to electric customers under FT contracts to ensure that gas is made available to generators consistent with their contracted entitlements on all modeled days.

The FT limits into SERC East and Southeast are somewhat flexible due to contract pathing and the nature of the shipper. For example, a marketer holding a Transco PA->AL contract may be more likely to deliver gas on a secondary basis within the path of their contract if prices are higher in SERC East than SERC Southeast. To this effect, LAI identified 965 MDth/d of Transco FT which could reasonably serve SERC East, despite having primary delivery in SERC Southeast. This seasonal adjustment aligns well with historical scheduled flows from 2018, where gas constraints closely tracked past system performance. In the SSE case, an additional 1,586.9 MDth/d of capacity is available, with 106.9 MDth/d allocated for local distribution and 1,480 MDth/d for power generation. Under this scenario, gas constraints for power generation increase by 400 MDth/d in SERC Southeast and 1,080 MDth/d in SERC East.

The following graphs validate the modeling assumptions by comparing historical scheduled flows with the estimated gas constraints, both with and without the SSE build case. The historical scheduled flows generally remain well below the maximum gas burn limit, indicating that additional capacity is available for power generation to withdraw more gas when needed. However, as demand for electric power grows and SSE shippers build more combined-cycle generators, gas demand for power generation will rise. Some of that increase in demand will be mitigated by the construction of Southgate, which adds 550 MDth/d into SERC East, with 300 MDth/d contracted by Duke. Southgate is assumed to be constructed in both scenarios.¹⁴¹ The gas constraint mostly results in non-gas fossil fuels being dispatched to meet load on high demand days, which generally coincide with high and low temperatures.

¹⁴¹ MVP Southgate previously received a CPCN from FERC, and has requested an amended certificate application.

Figure 28: SERC East Gas Constraint for Power Generation

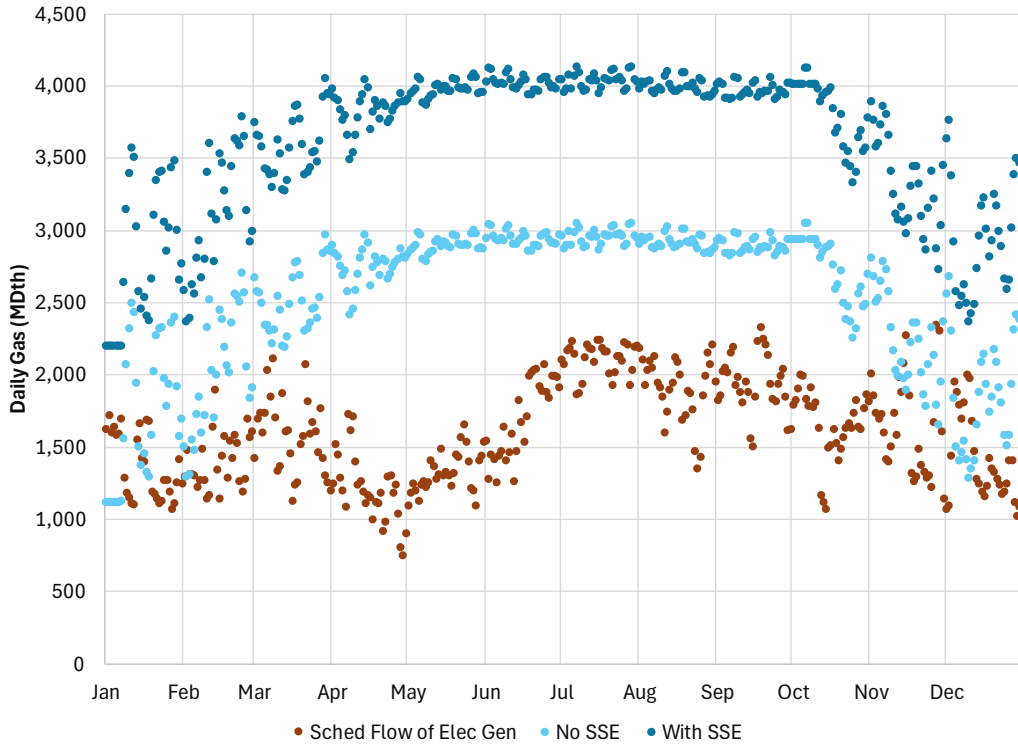
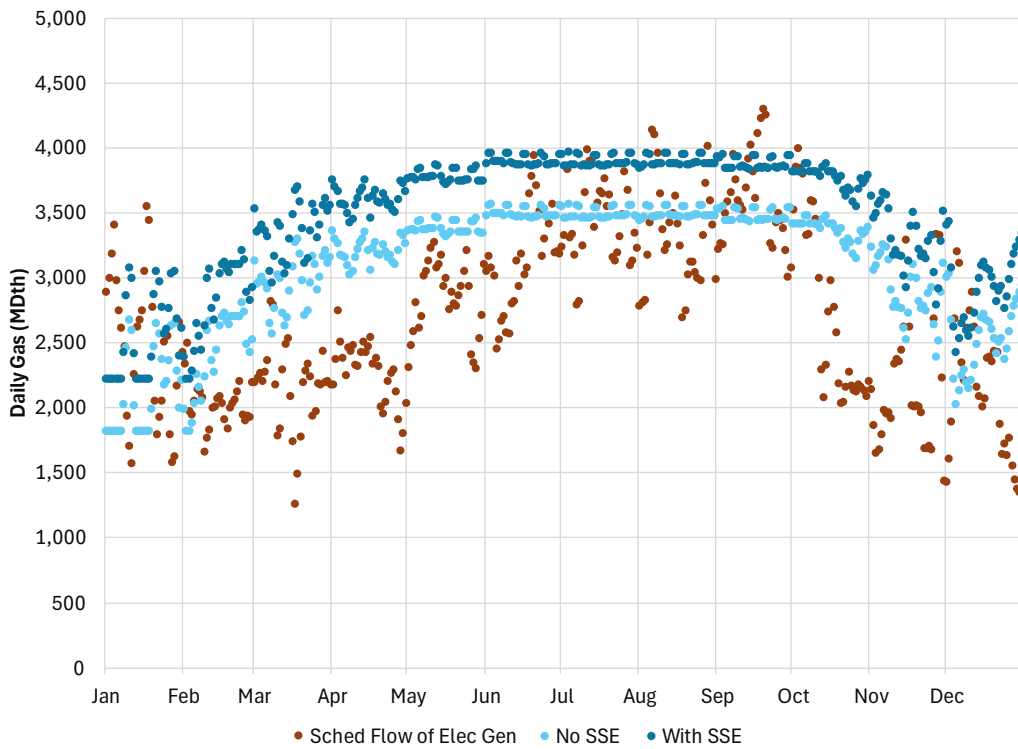


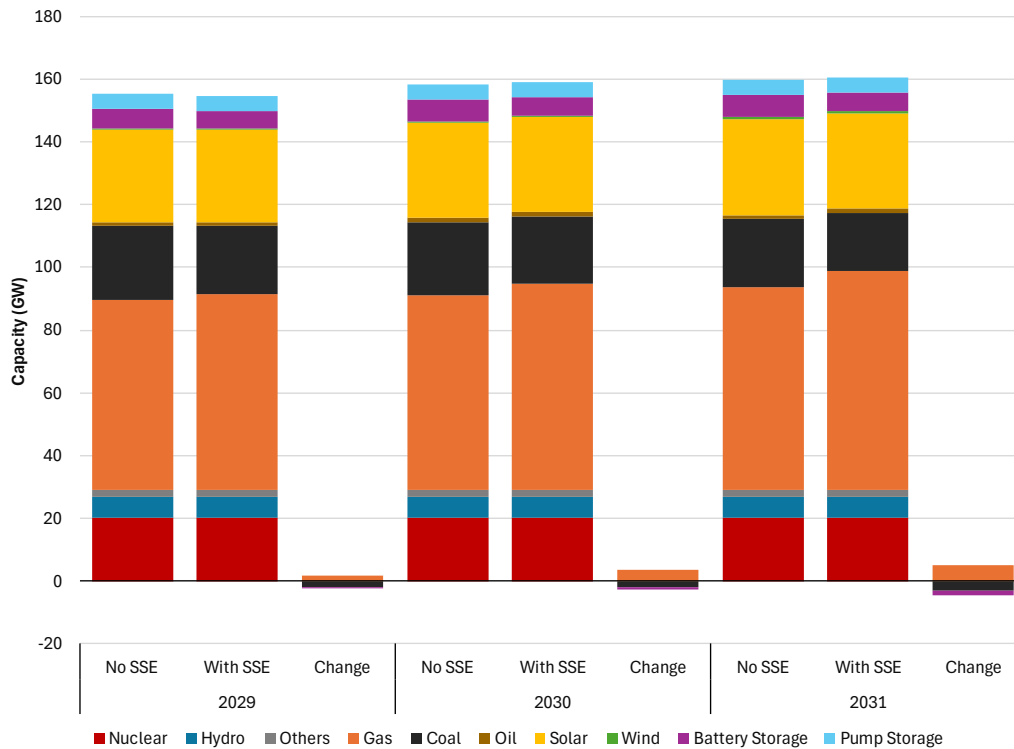
Figure 29: SERC Southeast Gas Constraint for Power Generation



4.3 Results

Figure 30 shows the total generation capacity in the study region without and with SSE, respectively. By 2031, the SSE case has 5,155 MW greater installed gas capacity and 3,106 MW less coal capacity than the study case without SSE.

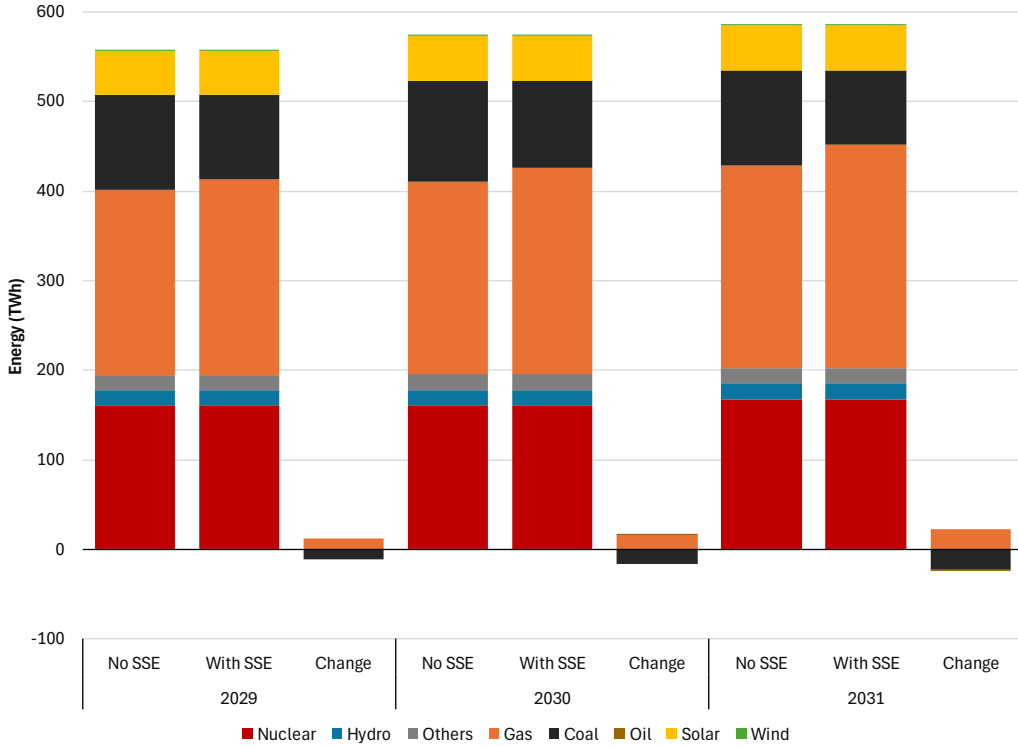
Figure 30: Generation Capacity in SSE and no SSE Cases, and Differences¹⁴²



The addition of SSE, and the associated gas-fired generation capacity that it enables, results in a significant change in the source of electric energy in the study region. Figure 31 shows the change in energy generation by fuel type between the study case without SSE and with SSE. By 2031, the addition of SSE results in an annual decrease of 23 TWh of coal generation, a reduction of 21% compared to the case without SSE. This reduction in coal generation is offset by a commensurate increase in gas-fired generation.

¹⁴² The “Others” category includes Biomass and Refuse.

Figure 31: Change in Energy with Addition of SSE



In addition to the changes in installed capacity, changes to the gas constraint from the inclusion of SSE also contribute to the ultimate fuel mix for electric supply in the study region. In the with SSE case, there are fewer days when the gas constraint binds, which results in less coal and oil being utilized. Additionally, the green bar in the two figures below shows that given the new combined-cycle resource additions enabled by SSE, additional gas is supplied as there are more days where gas consumption exceeds the No SSE daily gas constraint in the SSE case than days where the gas constraint binds in the No SSE case. The number of gas-constrained days in Zone 5 South decreases in both the with SSE and no SSE cases from 2029 to 2030 due to the addition of MVP Southgate.

Figure 32: SERC East (Transco Z5) Gas Constrained Days

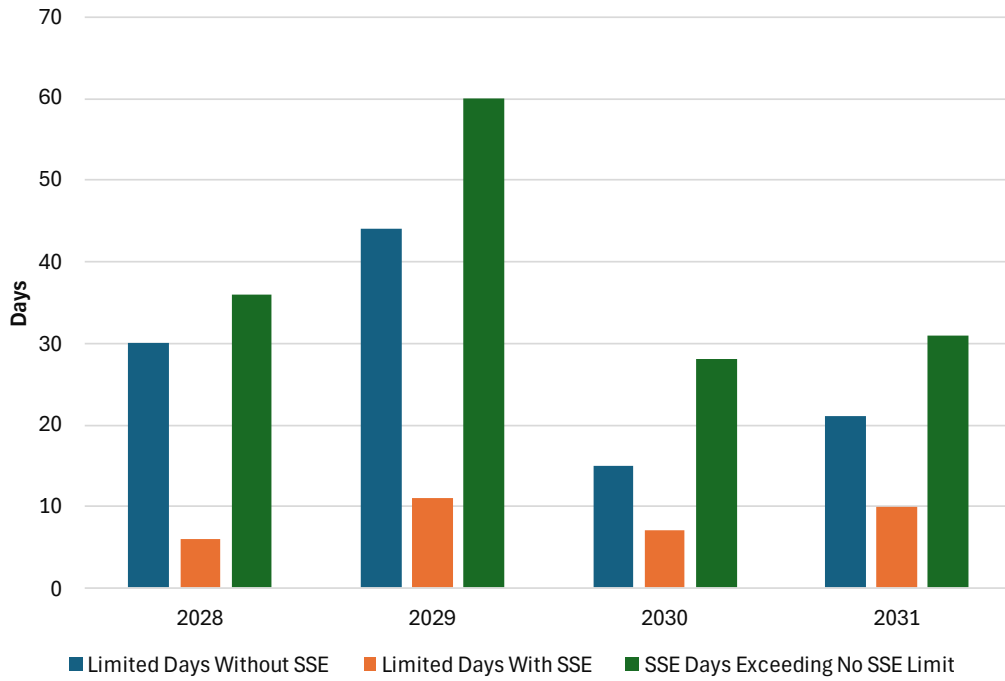
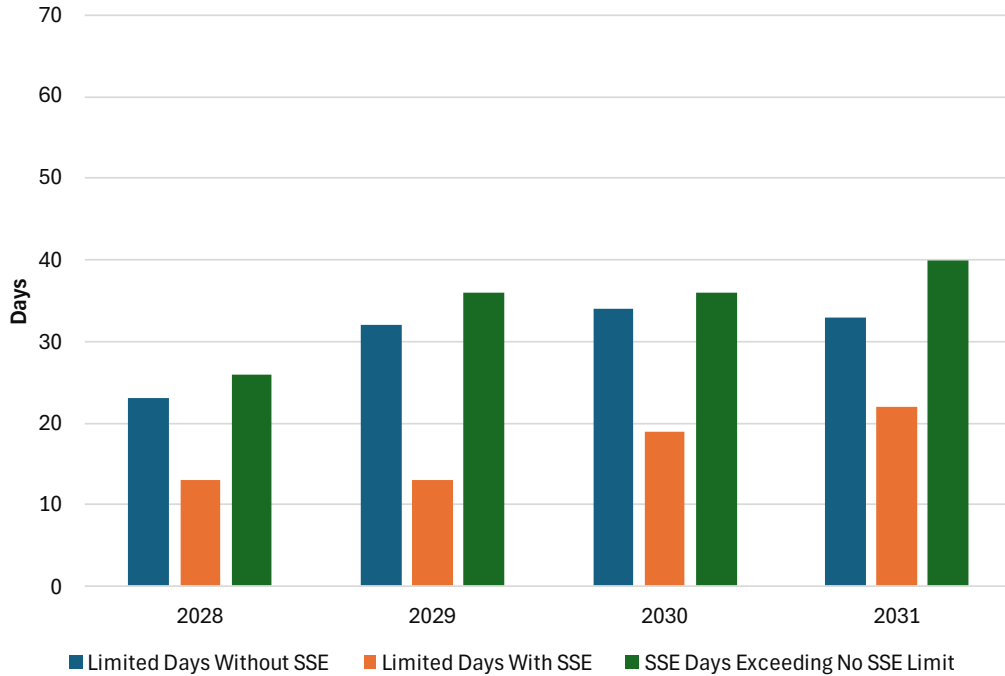


Figure 33: SERC Southeast (Transco Z4) Gas Constrained Days



Emissions Impact

In the January 22, 2025 Notice indicated that Commission Staff intend to prepare an environmental assessment (EA) for the SSE Project to be issued on November 7, 2025 addressing

factors including “concerns related to fossil fuel use and climate change; effects on environmental justice communities; impacts on water, wildlife, and cultural resources; property-specific impacts of pipeline construction; property values; safety; alternatives; cumulative impacts; need for increased natural gas supply in the region; and job creation.”¹⁴³ To aid Commission Staff in addressing concerns related to fossil fuel use and cumulative impacts, LAI has estimated reasonably foreseeable direct and indirect net GHG emissions attributable to SSE taking into account the net reduction in emissions from the displacement of other fuels, including natural gas delivered by other pipelines.

For direct emissions, LAI relied on the estimated net GHG emissions from SSE construction and operation reported by Transco in Resource Report 9.¹⁴⁴ LAI’s estimate of reasonably foreseeable indirect net emissions reflects downstream power sector emissions and downstream emissions from increased natural gas use by residential, commercial and industrial customers.

LAI’s modeling in Aurora tracks three types of emissions: carbon dioxide (CO₂), nitrogen oxides (NO_x), and sulfur dioxide (SO₂). The scenario with SSE in service results in lower values for all tracked emissions than the case without SSE. The primary driver of reduced net emissions is the displacement of coal generation with gas generation, which has a lower intensity of all tracked emissions.

¹⁴³ FERC, Notice of Schedule for the Preparation of an Environmental Assessment for the Southeast Supply Enhancement Project, January 22, 2025, Docket No. CP25-10-000.

¹⁴⁴ Transcontinental Resource Report No. 9 Air and Noise Quality Appendix 9A – Construction Emissions Calculations Southeastern Supply Enhancement Project October 2024, Docket No. CP25-10-000, page 1. Transcontinental Resource Report No. 9 Air and Noise Quality Appendix 9B – Operational Emissions Calculations Southeastern Supply Enhancement Project October 2024, Docket No. CP25-10-000, Potential to Emit Calculations Compressor Station 150 page 1, Potential to Emit Calculations Compressor Station 155 page 1 and Pipeline Fugitives and Blowdowns Calculations page 1.

Figure 34: Net CO₂ Emission Impact of SSE

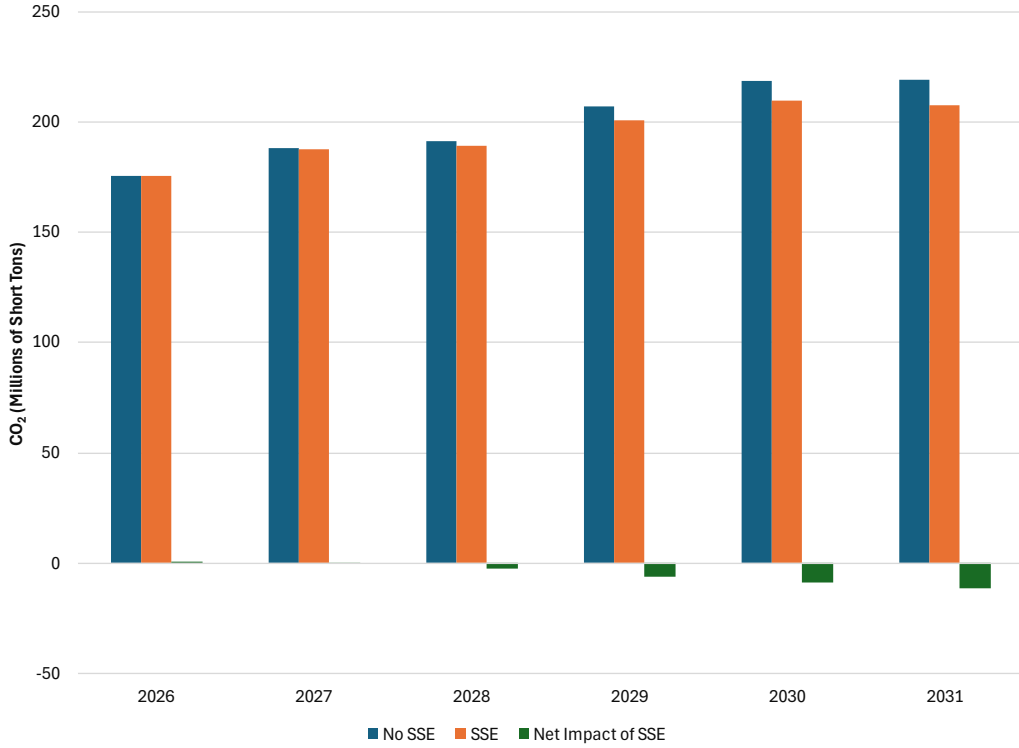


Figure 35. Net NO_x Emission Impact of SSE

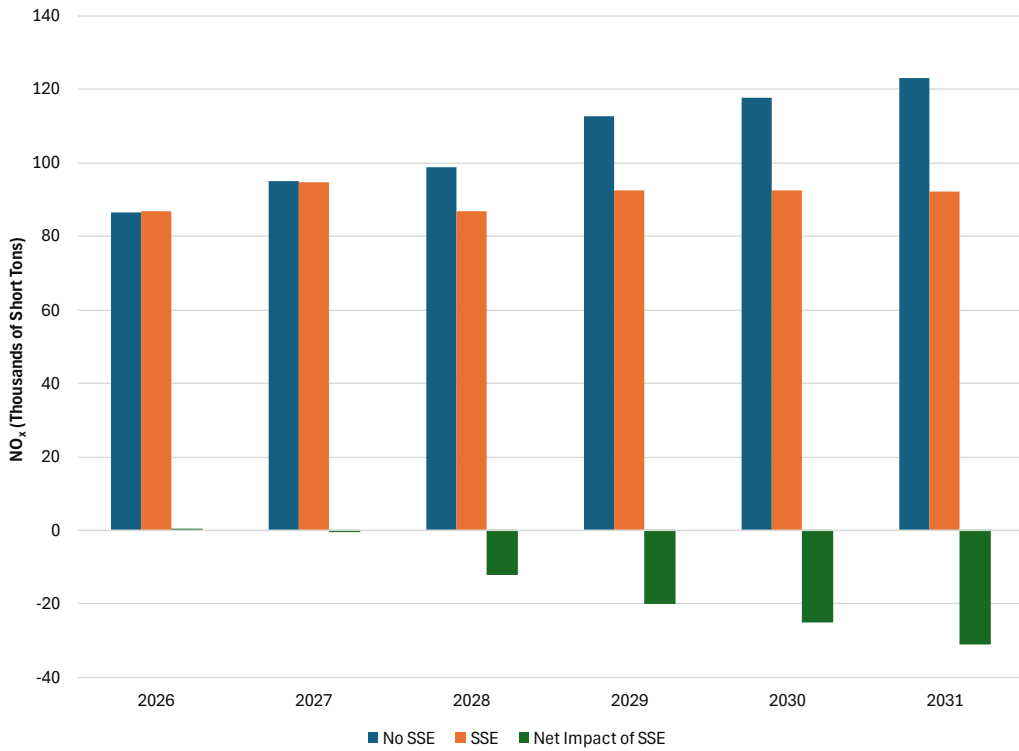
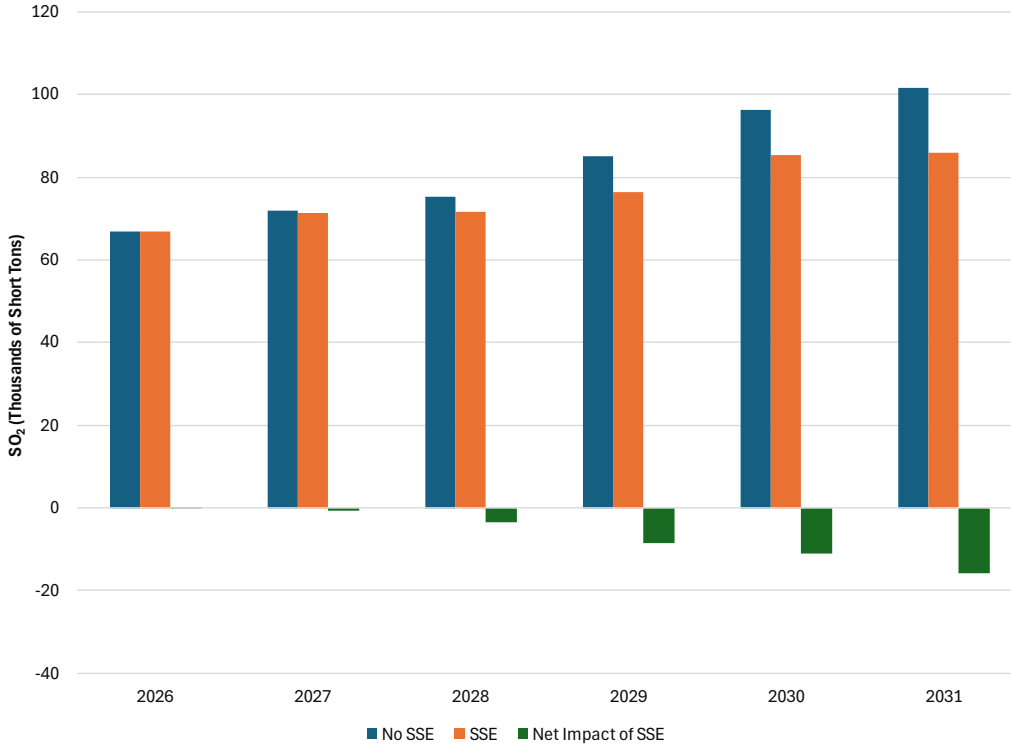


Figure 36: Net SO₂ Emission Impact of SSE



The SSE project, along with the efficient generation that it enables, provides annual emissions reductions of 7.2 million short tons of CO₂, 22.1 thousand short tons of NO_x, and 9.7 thousand short tons of SO₂ on average across 2028-2031. Notably, in 2028 SSE is in service, but no changes to the generation capacity have been made yet, and there are still emissions reductions. Emissions impacts increase over time as new generation is constructed.

As shown in Table 24, direct emissions from SSE’s construction and operation represent a small fraction of the reduction in indirect emissions from SSE’s operation. Furthermore, reported emissions from operation are overstated because the calculation assumes 100% utilization, 24 hours a day, 7 days a week.¹⁴⁵

Table 24: SSE Annual Direct Emissions (Short Tons)

Phase	CO ₂ e	NO _x	SO ₂
Construction	67,734	132	0.2
Operation	466,538	121	12.6

GPCM modeling shows a slight increase in LDC demand over the study period. LDC demand increases by 340 MDth annually, on average, from 2028 through 2031 in GPCM model output. This annual consumption increase yields a 20.4 thousand short ton increase in CO₂ emissions.

¹⁴⁵ Transcontinental Resource Report No. 9 Air and Noise Quality Southeastern Supply Enhancement Project October 2024, Docket No. CP25-10-000, p. 9-51.

Table 25: Emissions Rate Impacts of SSE (Short Tons per GWh)

Year	No SSE			SSE		
	CO ₂	NO _x	SO ₂	CO ₂	NO _x	SO ₂
2027	336.42	0.17	0.13	336.49	0.17	0.13
2028	348.29	0.18	0.13	347.56	0.18	0.13
2029	333.52	0.17	0.13	329.54	0.15	0.12
2030	371.84	0.20	0.15	360.20	0.17	0.14
2031	372.44	0.20	0.16	357.37	0.16	0.15

Production Cost Impact

The production cost metric includes fuel, start-up, variable operations and maintenance, and emission costs. With the addition of SSE, production costs decrease by \$639 million in 2031, with fuel savings accounting for 82% of this reduction. SSE enables the development of more efficient CC gas-fired units, totaling 7,080 MW, with an average capacity factor of around 91%. Meanwhile, older and less efficient units, particularly coal-fired plants – totaling 3,106 MW with an average capacity factor of approximately 49% are scheduled for retirement between 2029 and 2031. Coal steam turbines consume more fuel (on a thermal basis) than gas combined-cycle units to produce the same amount of electricity. Without SSE, oil is typically used alongside coal and existing gas-fired generators to meet winter demand.

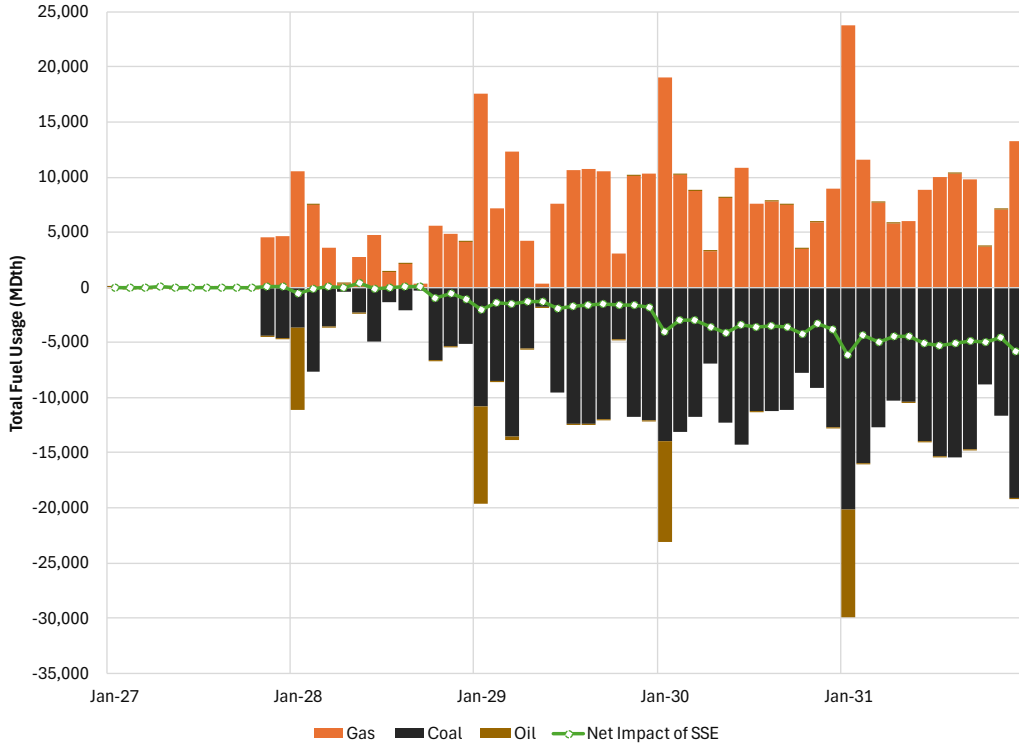
Table 26: Net Production Cost Impact (in Millions) with Addition of SSE

Year	Coal	Gas	Oil	Others	Net Impact of SSE
Nov-Dec 2027	-\$48.6	\$44.3	\$0.0	-\$0.2	-\$4.6
2028	-\$225.5	\$171.0	-\$189.7	-\$6.1	-\$250.3
2029	-\$645.3	\$488.8	-\$238.2	-\$8.8	-\$403.5
2030	-\$761.9	\$434.7	-\$234.8	-\$9.2	-\$571.3
2031	-\$968.4	\$597.0	-\$255.8	-\$11.9	-\$639.0

Table 27: Annual Change in Total Fuel Usage (MDth) with Addition of SSE

Year	Coal	Gas	Oil
Nov-Dec 2027	(9,019)	9,157	(1)
2028	(43,271)	47,926	(7,518)
2029	(114,950)	104,968	(9,346)
2030	(135,480)	101,564	(9,114)
2031	(168,178)	117,910	(9,729)

Figure 37: Change in Total Fuel Usage with Addition of SSE



Through reducing the use of coal and oil, SSE and the resources it enables reduce production costs, which are passed through to electric ratepayers, by \$466 million on average from 2028-2031.

4.4 Sensitivities

LAI conducted several modeling sensitivities to identify how benefits of SSE would increase if other model inputs change. The first sensitivity shows the impact of daily gas price volatility on the results. The second sensitivity shows the impact of updated load and resource assumptions from Georgia Power’s 2025 IRP, which has not yet been approved by the Georgia PSC.

Daily Gas Price Volatility Sensitivity

Adding SSE capacity also creates benefits during severe cold days that are not captured through GPCM’s monthly average price forecast. In 2018, the Transco Zone 5 South price exceeded \$10/MMBtu in a number of days. As power generation is often a marginal customer on the gas system, it follows that as gas volumes are limited by pipeline constraints on a given day, the daily gas price will rise to the cost of oil (or greater) when generators are competing for scarce supply. Therefore LAI tested an Aurora sensitivity where gas prices were adjusted upwards to reflect daily price volatility.

LAI used the Aurora base case results in order to determine the number of days where the daily gas constraint bound in SERC East and Southeast, respectively, and led to oil burn during the winter. After identifying these days, LAI increased gas basis at these points to the greater of the

actual 2018 gas basis to Henry Hub on those days, or the difference between Henry Hub and the shadow price of the constraint, which represents the cost of oil.¹⁴⁶

This change results in oil dispatch increasing during days where daily volatility adjustments are applied. There are fewer days with the daily volatility adjustment applied in the SSE case than the No SSE case, as the gas constraint binds less often. To the extent that coal and oil generators cannot cover power demand during these days, gas is burned at high cost.

Table 28: Net Production Cost Impact (in Millions) with Addition of SSE, Gas Price Volatility Sensitivity

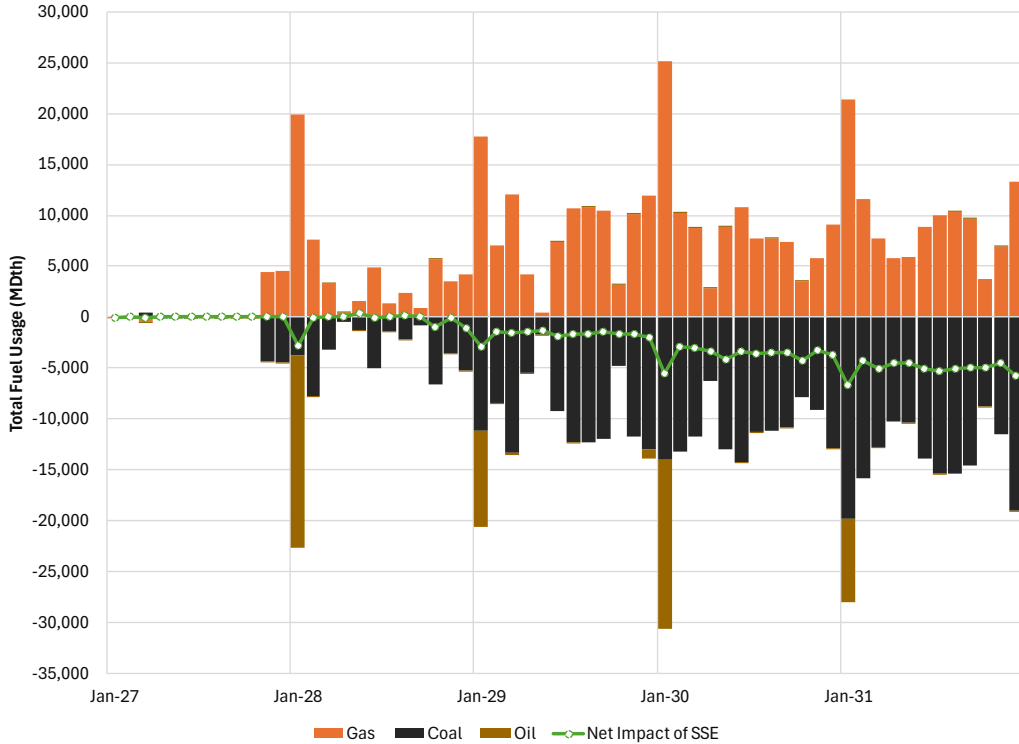
Year	Coal	Gas	Oil	Others	Net Impact of SSE
Nov-Dec 2027	-\$48.0	\$43.3	\$0.0	-\$0.2	-\$5.0
2028	-\$217.4	\$97.2	-\$478.6	-\$7.3	-\$606.2
2029	-\$652.0	\$339.6	-\$274.1	-\$9.1	-\$595.5
2030	-\$763.2	\$327.1	-\$431.4	-\$10.8	-\$878.3
2031	-\$965.2	\$534.4	-\$222.2	-\$13.1	-\$666.1

Table 29: Annual Change in Total Fuel Usage (MDth) with Addition of SSE, Gas Price Volatility Sensitivity

Year	Coal	Gas	Oil
Nov-Dec 2027	(8,874)	8,971	(1)
2028	(41,144)	55,479	(18,959)
2029	(115,523)	105,929	(10,753)
2030	(135,633)	107,906	(16,653)
2031	(167,775)	115,333	(8,229)

¹⁴⁶ The shadow price represents the marginal value of the daily gas constraint. It represents the reduction in production cost, in dollars, if the daily fuel limit was increased by one MMBtu.

Figure 38: Change in Total Fuel Usage with Addition of SSE, Gas Price Volatility Sensitivity



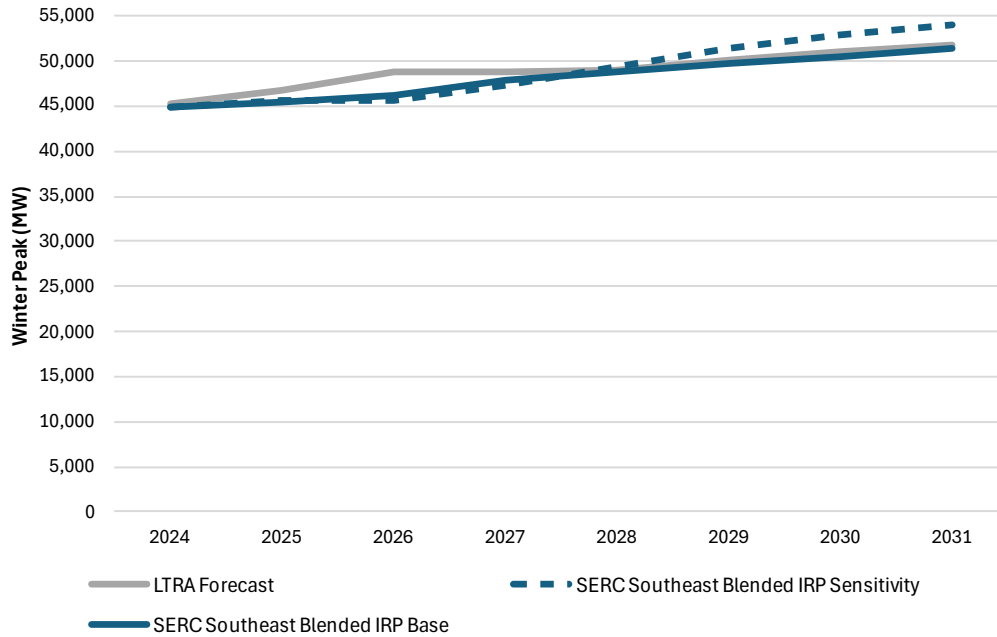
This sensitivity shows annual emissions reductions of 7.2 million short tons of CO₂, 28.2 thousand short tons of NO_x, and 10.6 thousand short tons of SO₂ on average across 2028-2031. NO_x and SO₂ emissions impacts increased relative to the base case due to relatively higher oil switching.

2025 Georgia Power IRP Sensitivity

LAI also conducted a modeling sensitivity that modified the base case to consider changes to the load and resource mix that Georgia Power filed in its 2025 IRP on January 31, 2025. This IRP builds upon the 2023 IRP Update, which was approved by the Georgia PSC in April 2024. The company anticipates an annual load growth of 7% through the winter of 2030/31, with a peak demand increase of 2,200 MW compared to the 2023 IRP Update forecast.¹⁴⁷

¹⁴⁷ Georgia Power, 2025 IRP Technical Breakdown, Page 1, January 31, 2025
<https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/2025-irp-docket-overview.pdf>

Figure 39: SERC Southeast LTRA and LAI's Blended IRP winter peak Forecasts with Sensitivity



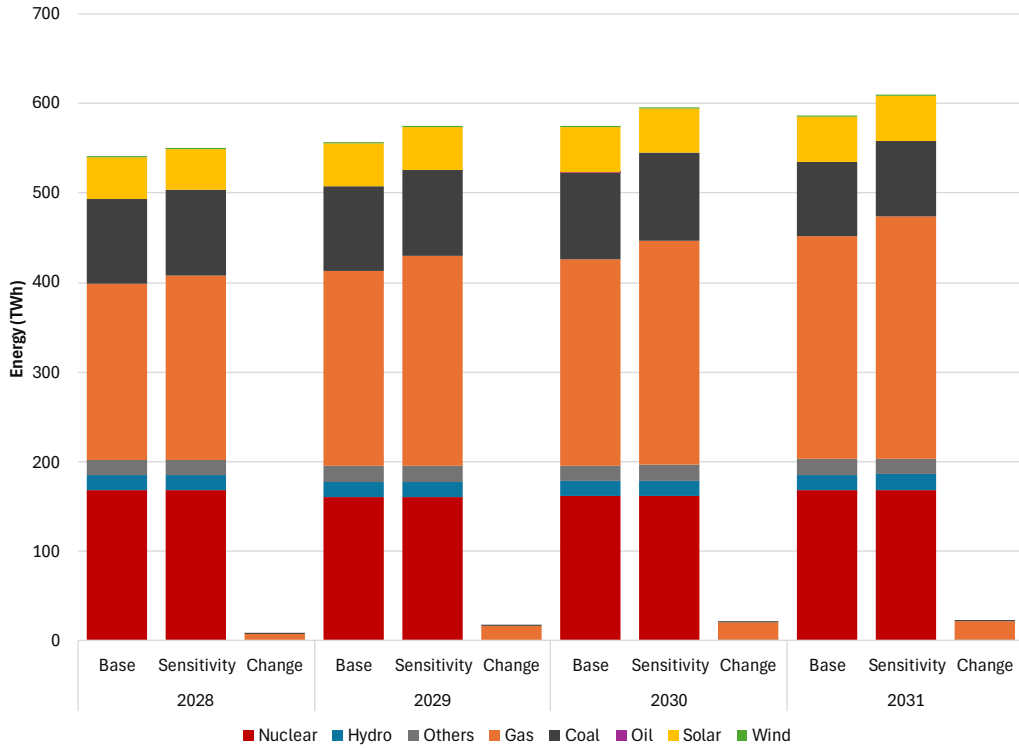
On the supply side, Georgia Power has requested to defer the retirement of Plant Gaston Units 1-4, A, and Plant Scherer Unit 3 from December 31, 2028, to the end of 2035. This extension will add 1,007 MW of existing capacity at the start of winter 2028/29. Additionally, the company plans incremental uprates across 14 existing gas and nuclear units, contributing 380 MW by 2034. The uprate is expected to begin in winter 2027/28. Georgia Power also aims to maintain 665 MW of existing hydro capacity.¹⁴⁸ Combining these actions with the All-Source RFP approved in the 2022 IRP, capacity needs between 2029 and 2031 will be met.¹⁴⁹ LAI did not conduct additional modeling iterations between Aurora and GPCM for this sensitivity, as it is meant to provide insights on the effects of increased power demand on power market outcomes.

The sensitivity inputs were applied both with and without SSE; the but-for excursions remain unchanged. In 2031, generation increases by 7.7% compared to the base case, with nearly all of this additional demand met by increased gas generation.

¹⁴⁸ Georgia Power, 2025 IRP Main Document, Page 59-60, January 31, 2025
<https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/2025-Integrated-Resource-Plan.pdf>

¹⁴⁹ To meet capacity requirements through 2032 and 2033, beyond the modeled study period, the company plans to issue an All-Source Capacity RFP in Q3 2025. *Id.*, page 3

Figure 40: Generation Capacity with SSE in Base and IRP Sensitivity, and Differences



The IRP sensitivity analysis shows an additional emissions impact with SSE. Over the study period, CO₂ emissions decrease by an additional 1.2 million short tons, while NO_x and SO₂ emissions drop by an additional 10.8 thousand and 14.9 thousand short tons, respectively. Emission reductions continue to grow over time.

Figure 41: Net CO₂ Emission Impact of SSE with IRP Sensitivity

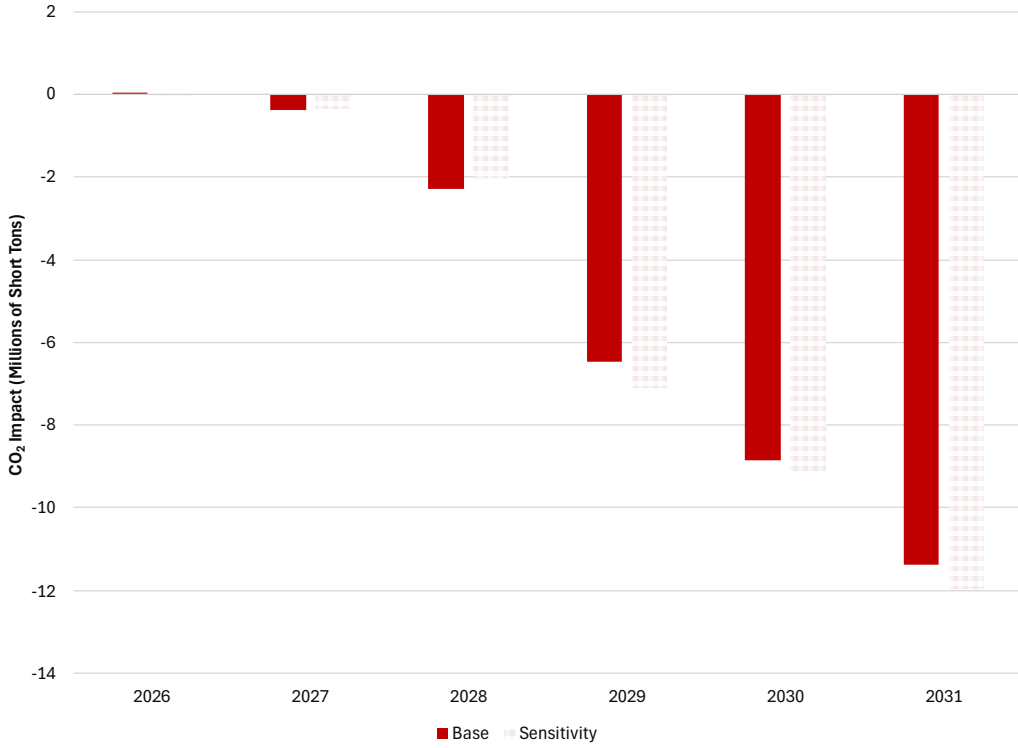


Figure 42: Net NO_x Emission Impact of SSE with IRP Sensitivity

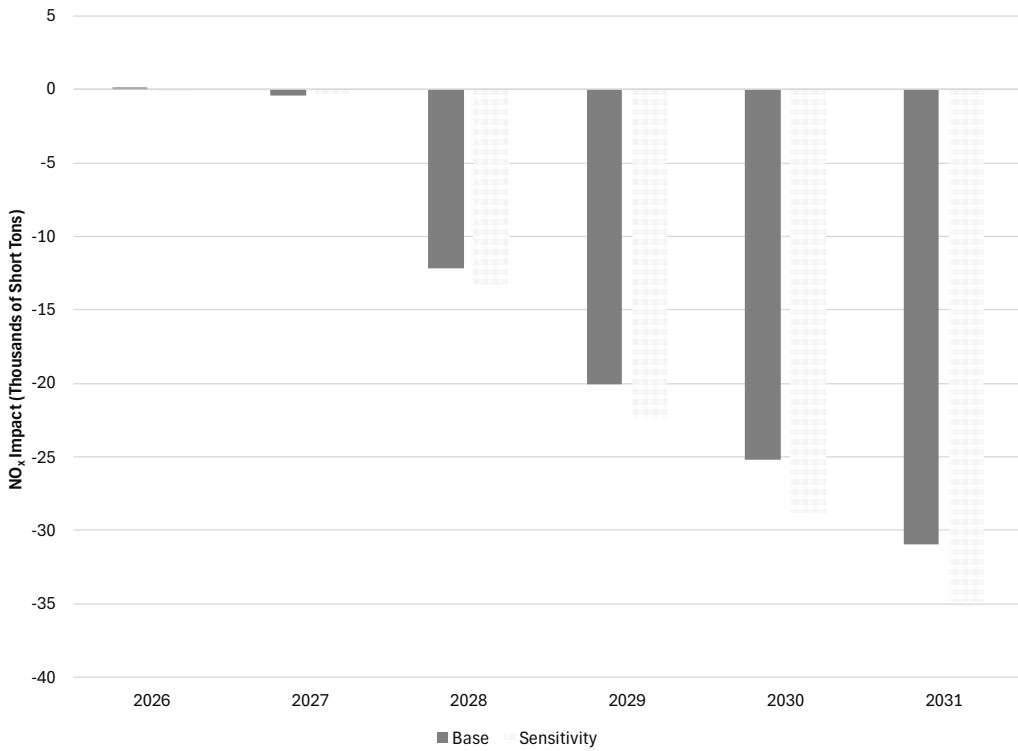
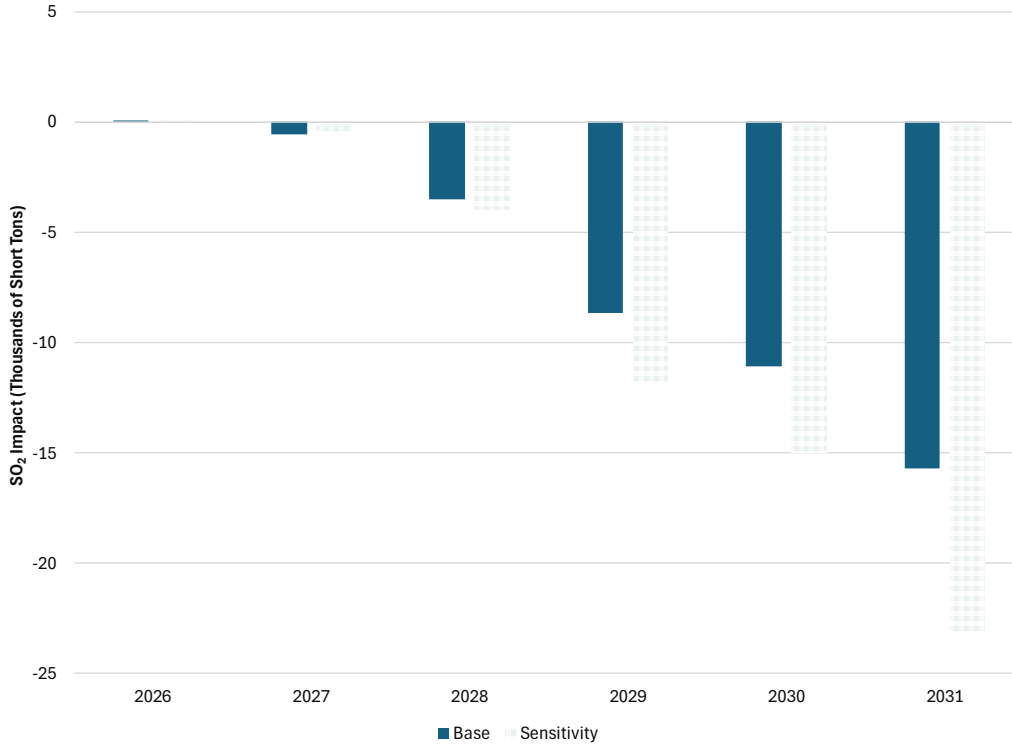


Figure 43: Net SO₂ Emission Impact of SSE with IRP Sensitivity



With the increase in winter peak demand and gas consumption for power generation in the sensitivity case, SSE's impact rises by \$212.9 million from November 2027 through the end of 2031, relative to the base case. Production costs decline by \$718 million in 2031, with fuel savings contributing 83% of this reduction. By reducing reliance on coal and oil, SSE and associated resources lower production costs, leading to an average reduction of \$519.1 million for electric ratepayers from 2028 to 2031.

Table 30: Net Production Cost Impact (in Millions) with Addition of SSE, IRP Sensitivity

Year	Coal	Gas	Oil	Others	Net Impact of SSE
Nov-Dec 2027	-\$40.9	\$35.6	\$0.0	-\$0.1	-\$5.4
2028	-\$206.6	\$154.4	-\$213.7	-\$5.2	-\$271.1
2029	-\$687.8	\$523.9	-\$264.8	-\$9.1	-\$437.8
2030	-\$764.4	\$418.1	-\$293.9	-\$9.2	-\$649.4
2031	-\$999.2	\$601.0	-\$308.4	-\$11.4	-\$718.0

The sensitivity case results show that as power demand grows under the higher 2025 IRP forecast SSE will provide additional benefits to ratepayers. Under this sensitivity, the marginal unit is less efficient, so the combined-cycle generation and reduced gas supply constraints that SSE enables are more impactful.

5 Conclusions

LAI has reached four primary conclusions:

1. Rapid economic growth expected in Carolinas and Georgia drives growing electricity demand in Duke and Georgia Power's service territories. Between 2023 and 2031, Duke forecasts that its winter peak demand will grow at an annual rate of 2.1% per year. Georgia Power's winter peak is forecasted to grow at 5.5% per year. Both Duke and Georgia Power need new fuel secure gas generation plants to keep pace with robust demand growth.
2. LAI's review shows that the shippers plan to add gas-fired generators to meet rapidly increasing power demand. Duke expects to build three 1,360 MW combined-cycle plants with gas demand requirements of 705 MDth/d in the aggregate. Duke's contracted FT on SSE totals 1,000 MDth/d. Georgia Power requires substantial amounts of new capacity resources to come online from 2029 to 2031, and their base scenario for supply portfolio modeling that was provided to support their resource plan includes the addition of about 4,800 GW of gas-fired generation by 2031. LAI's review of various pipeline operating patterns and pricing data sources show that pipelines that deliver gas to the shippers are highly utilized. In 2024, Transco Zones 4 and 5 were under an OFO on 89% of days, which indicates very high segment utilization. Elevated pricing in Zone 5 South relative to other leading price benchmarks underscores the adverse price impact attributable to frequent congestion. Frequent restrictive congestion patterns observed in 2024 set the basis for the need for new pipeline infrastructure. Other gas and non-gas alternatives may be able to serve a portion of both Duke's and Georgia Power's incremental demand requirements, but do not represent a bankable solution to the challenge of expanding existing infrastructure to serve anticipated demand growth.
3. GPCM gas transportation modeling shows that the SSE project meets increasing gas demand while lowering delivered gas prices in the study region. The project enables more southbound gas to serve the study region, replacing much of the south-to-north flows from upstream of Transco Station 85. The iterative electric- and gas-side modeling found that with these changes, delivered prices in Zone 4 and Zone 5 South would decrease by \$0.03/MMBtu and \$0.06/MMBtu, respectively, between 2028-2031. Price effects are limited due to the addition of gas-fired generation that performs as a baseload resource in the SSE case.
4. Aurora production cost modeling shows that the SSE project reduces GHG emissions by allowing for more natural gas generation to replace coal generation, which also results in substantial generation supply cost savings for electric ratepayers. This reduction in emissions far exceeds the emissions created by constructing and operating the SSE facilities. The SSE project, along with the efficient generation that it enables, provides annual power sector emissions reductions of 7.2 million short tons of CO₂, 22.1 thousand short tons of NO_x, and 9.7 thousand short tons of SO₂ on average across 2028-2031. LAI also projected that electric power production cost savings from 2028-2031 would average about \$466 million with SSE relative to a No SSE case. Emissions reductions and

production cost savings further increased under a sensitivity incorporating demand growth and resource changes from the 2025 Georgia Power IRP, which has not yet received state commission approval.

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