BEYOND THE POWER PLANT

THE HIDDEN COSTS OF GAS-FIRED GENERATION

An analysis of the costs of gas transmission expansion due to increasing electric system demand in the U.S.

JUNE 2026

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Overview

Since 2023, U.S. electricity demand projections have surged, driven primarily by data centers and large industrial consumers. In response, many electric utilities are proposing extensive expansions of their gas-fired generating fleets, selecting these resources over alternatives such as wind, solar, battery storage, and demand-side resources. These selections are typically justified on the premise that new loads — particularly those with high load factors — require firm, dispatchable generation capable of operating at high capacity factors, a need that, in the view of some utilities, can only be met cost-effectively by fossil fuel-fired units.

However, **the planning processes underlying the nationwide "rush to gas" may not fully reflect the total system costs associated with new gas generation**. As documented in GridLab's recent report on gas turbine costs, planning assumptions for gas-fired plants have frequently understated current market conditions for generator capital costs.[1] A related and often underexamined dimension of this issue, and the focus of this report, is **the omission or understatement of the fuel supply and transportation infrastructure costs required to support the new gas-fired power plants**.

New gas generation resource additions increase demand for natural gas supply, transportation, and storage services. According to Global Energy Monitor there are over 250 GW of gas power plants in development in the US,[2] which equates to about 38 Bcf/d of peak gas demand — or about 17 times the amount of interstate pipeline capacity added in 2025.[3] For the gas-fired capacity to be dispatchable any time, fuel needs to be readily available leading to incremental demand for new firm transportation (FT) rights and, in some cases, expansion of the underlying gas infrastructure. Such expansions can include new interstate or intrastate pipeline capacity, additional compressor stations, new or expanded liquefied natural gas (LNG) storage facilities, and other fuel storage or delivery infrastructure.

1 GridLab, *The New Reality of Power Generation: An Analysis of Increasing Gas Turbine Costs in the U.S.* (2025, September), https://gridlab.org/portfolio-item/gas-tubine-cost-report/.

2 Martos, J. "Betting big on data centers, U.S. now leads world for new gas power development," Global Energy Monitor, January, 2026. https://globalenergymonitor.org/research/betting-big-data-centers-us-now-leads-world-new-gas-power-development

3 Assumes approximately 0.15 Bcf/d per 1 GW of generation capacity. According to EIA, approximately 2.2 Bcf of interstate capacity was added in 2025. See: https://www.eia.gov/todayinenergy/detail.php?id=67225

The capital costs and ongoing expenses associated with fuel infrastructure can comprise a significant portion of the total cost to build and operate new gas-fired generating plants, yet they are often evaluated separately from — or not considered in combination with — the proposed generation investment.

This report addresses this material but often overlooked dimension of the costs associated with the nationwide expansion of gas-fired generation: the fuel supply and transportation infrastructure required to support new gas-fired plants. The report begins with an overview of that challenge, then catalogs the types of gas expansion costs at issue and examines the distortions that arise from a bifurcated regulatory system in which generation and fuel infrastructure costs are evaluated separately. A case study of Wisconsin Electric Power Company illustrates how these costs manifest in practice. The report then presents key findings drawn from Current Energy Group (CEG)'s work across the country, with supporting case studies included in the Appendix, before concluding with solutions to improve transparency and affordability in resource planning. Below is a summary of six key findings, which CEG intends to continue exploring and validating in future Phases of research:

1. Power generation needs are an increasingly large fraction of interstate gas pipeline demand.
2. New gas-fired power plants are often being proposed in tandem with corresponding gas infrastructure projects.
3. New gas transmission projects are a major component of utilities' overall fixed costs (e.g., capital investment or long-term contract) supporting new power delivery.
4. Assumptions for gas transmission costs used in electric system modeling are relatively simplistic and may be underestimated.
5. Electric utilities directly pass through the costs and risks of gas transmission projects to their retail customers.
6. It is unclear how the costs of the new gas transmission projects driven by new large loads will ultimately be shared between new large loads and existing customers.

These overlooked upstream infrastructure costs and pipeline expenses represent a "hidden cost of gas" that threatens ratepayer bills. However, to the extent alternatives to gas are considered those risks can be minimized.

The Fuel Supply Chain

What gas-fired generation actually requires

Gas-fired generating plants require a continuous and reliable supply of natural gas to operate. This has two distinct dimensions: physical delivery — the infrastructure and capacity to move gas from the wellhead to the plant under normal conditions — and security of supply (i.e., via firm contract), which ensures that fuel remains available and deliverable during periods of stress, such as peak demand, extreme weather, or pipeline disruptions. Physical delivery requires a chain of pipeline infrastructure spanning interstate transmission systems, intrastate pipelines, and plant-level connections. Security of supply may require additional infrastructure (e.g., pipelines, storage facilities, etc.) but also requires contractual arrangements at each of those levels.

Each of these infrastructure layers carries real and significant fixed costs (e.g., capital investments, long-term contracts) that can extend for decades. As discussed further in this report, those costs are not always fully captured or evaluated in an integrated manner in electric utility resource planning proceedings — and when omitted or evaluated in isolation from the generation investment they support, they can materially understate the true cost of new gas-fired generation.

Physical Delivery

At the plant level, several infrastructure components are required to physically connect the generating facility to the pipeline system and ensure reliable fuel supply. These include **onsite or near-site laterals,** which link the plant to the main pipeline network. In some cases, plants may have the ability to maintain **onsite fuel storage or dual-fuel capability** as a backup against short-term supply interruptions (for example, the ability to switch to fuel oil or diesel if gas supply is curtailed). However, this is not feasible in all cases due to technical or permitting constraints. These secondary fuel arrangements provide a limited but important

buffer, particularly during extreme weather events or pipeline outages when gas supply may be constrained. Plant-level infrastructure costs are typically borne by the plant owner and are generally included in utility capital cost estimates submitted in regulatory proceedings such as Integrated Resource Plans (IRPs) or Certificate of Public Convenience and Necessity (CPCN). However, the applications in these proceedings may not always include the laterals or onsite fuel storage components, or else these components are preliminary and highly uncertain in nature.

Moving outward from the plant, **pipeline system infrastructure** may need to be expanded to accommodate new demand. This can involve the **installation or expansion of compressor stations**, which increase the throughput of existing pipelines, or more **extensive pipeline expansion projects** such as looping or constructing new pipe segments to add capacity to the transmission system. The costs associated with these types of projects are paid for by the pipeline owner, which may include the local gas utility. This owner will typically seek cost recovery through increased gas transmission rates that are ultimately charged to the power plant.[4]

Security of Supply

At the intrastate and interstate pipeline level, fuel security depends on access to sufficient pipeline capacity to move gas from supply sources to the plant. This is typically secured through **firm transportation ("FT")** agreements, which reserve pipeline capacity on a long-term basis in exchange for fixed reservation charges. Without FT, a plant relying on **non-firm or interruptible transportation ("IT")** faces the risk of curtailment precisely when demand is highest. This has implications for the resource adequacy value of the plant although such impacts are not always fully considered in electric system studies.

4 Interstate pipelines require approvals through the Federal Energy Regulatory Commission (FERC). FERC's certificate process requires demonstration of market need, typically evidenced by precedent agreements (signed firm contracts) before a pipeline is approved and constructed. More information about natural gas pipeline approvals, including pending projects, is available at: https://www.ferc.gov/natural-gas/natural-gas-pipelines

Alternatively, fuel security might be achieved through access to **LNG or underground gas storage facilities** that ensure fuel availability during periods of pipeline supply disruptions or constrained delivery. Access to storage involves separate contractual arrangements that provide rights to inject, store, and withdraw gas from storage facilities, or direct ownership and operations of storage facilities by the local utility.

TABLE 1. Categories of Gas Transmission Projects

CATEGORY	DESCRIPTION
Onsite/Near-Site Laterals	Short pipeline connections linking the power plant to the main pipeline system.
Onsite/Near-Site Storage	Small-scale fuel storage facilities used to ensure short-term fuel availability.
Onsite Secondary Fuel Capabilities, Storage, & Transportation	Dual fuel generating capability, storage & transportation of diesel.
Compressor Stations (Onsite or Offsite)	Installation or expansion of compressor to increase the throughput of existing pipelines.
Pipeline Expansion	Upgrades to the interstate or intrastate pipeline system to provide additional capacity (e.g., looping, new pipe segments).
Non-firm / Interruptible Transportation (IT)	Lower-cost transportation service that can be curtailed when pipeline capacity is constrained. One-part rate: 1) Usage Charge ($/Dth).
Firm Transportation (FT)	Long-term reserved pipeline capacity that guarantees delivery of gas to the plant. Two-part rate: 1) Fixed Reservation ($/Dth/month); 2) Usage Charge ($/Dth).
Capacity Release	Firm shipper can resell their firm rights. Cost for buyer, revenue for seller.
LNG or Underground Storage (Offsite)	Larger, often underground storage projects; also allows for capacity release of storage rights. Firm storage agreements give guaranteed injection and withdrawal rights.

Fragmented Oversight

Incremental fixed costs span across the electric and gas systems

Hidden costs arising from a bisected electric/gas system

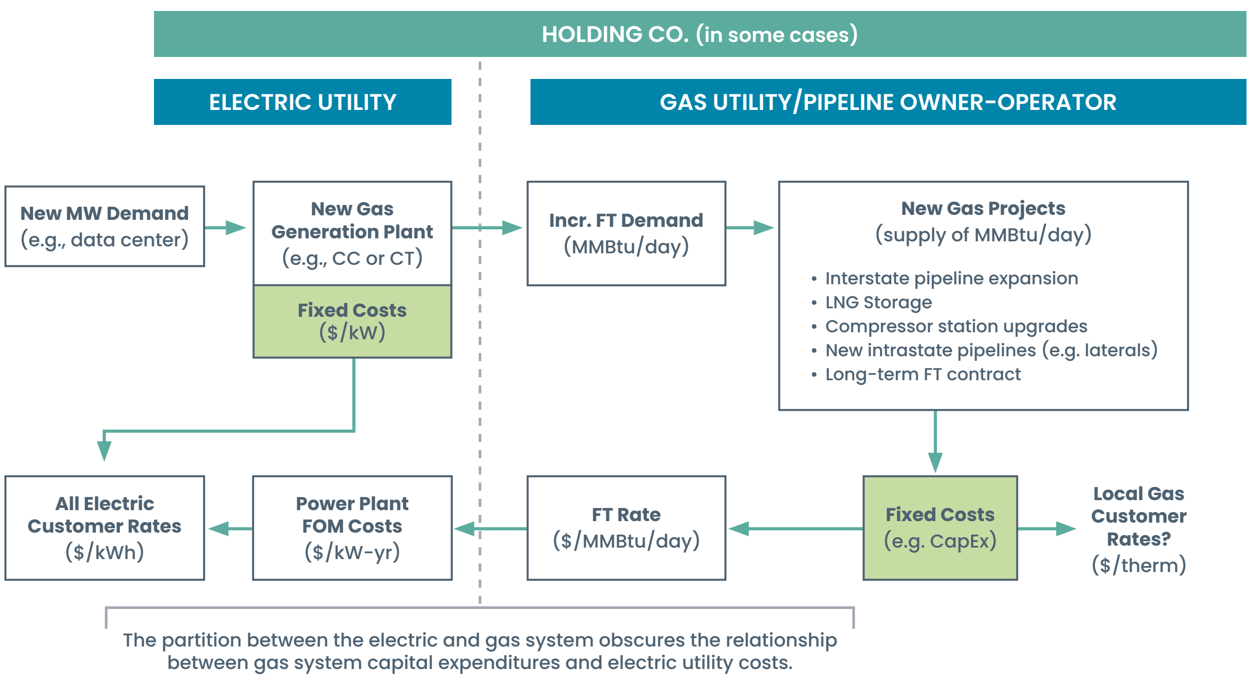
As affordability has become a central concern among utility stakeholders, ensuring adequate oversight of gas transmission projects for power demand presents a unique challenge. The challenge is not that fuel infrastructure is needed — it is that the fixed costs of providing fuel security are not always fully or consistently evaluated as part of the initial decision to build new gas-fired generation. This can lead to an incomplete or "apples to oranges" evaluation when gas-fired generation is compared to alternatives such as solar, wind, battery storage, and demand-side resources.

In CPCN applications for new generators, capital costs for power plants are typically the primary focus. While a proxy for pipeline transportation costs may be considered alongside fuel commodity costs, these proxy costs typically don't account for the incremental cost of fuel security (i.e., the new FT contracts or fuel storage facilities required to make a gas plant reliably dispatchable). As such, the incremental costs of new gas transmission projects are not fully evaluated alongside the generation investment that necessitates them. In this sense, the full picture of new investment costs that electric customers must bear may be obscured or hidden.

This is partly a sequencing problem due to the **fragmented regulatory structure governing the electric and gas systems**, as depicted in Figure 1. If a generation plant is approved first; the fuel security question will inevitably follow. However, this typically occurs in a separate proceeding, after the commitment to build gas generation has already been made and generation alternatives are no longer being considered. For example, storage facilities may require their own CPCN (or equivalent), filed after the generating units have been approved. Meanwhile, FT contracts often have no dedicated approval mechanism. Utilities typically negotiate and execute FT agreements directly and usually recover costs through fuel adjustment clauses or fuel dockets with limited oversight of capital investments.

The result of this bifurcation is that the total cost exposure for ratepayers is dispersed across regulatory proceedings and rate recovery mechanisms in a way that can obscure the full picture. Each proceeding evaluates only a portion of the cost, and no single proceeding captures the full amount. Once a generator is approved, the fuel security commitment becomes unavoidable and ratepayers are likely to incur fixed costs that no longer have a viable alternative, even if one existed initially. Moreover, ratepayers also fully bear the risk if fuel security investment costs significantly exceed their initial estimates. Finally, there is also the potential for stranded assets since gas pipeline infrastructure may outlive the useful life of a gas generator. Even if the gas generator has a long life, its utilization may decrease over time, leaving some portion of the pipeline or other supporting infrastructure's fixed costs to become stranded.

FIGURE 1. The Fragmentation of Electric and Gas Systems



Further complicating this matter is the fact that many details related to pipeline capacity contracts and fuel supply arrangements are treated as confidential within specific gas regulatory proceedings. This makes it more challenging for electric system planners to fully evaluate the costs and risks involved. It may also be difficult for electric system planners to determine the level of planning certainty involved in gas system projects, and vice versa.

Overlapping federal and state jurisdictions

Gas transmission projects for power generation can also occupy a "gray area" between overlapping federal and state jurisdictions. Delivery of gas fuel to new power plants typically involves a combination of both ***inter***state gas transmission projects that fall under federal jurisdiction and ***intra***state pipelines and other gas projects that fall under state jurisdiction. However, both of these types of projects are important for the reliability and costs of the power generation projects involved. Additionally, as described, there may be different utilities that operate the gas and power systems.

The fact that these overlapping jurisdictions and footprints exist can complicate the oversight role over gas projects that are increasingly needed for power delivery. As such, it is more important than ever for policymakers to be mindful of the interactions between these overlapping entities and strive to eliminate gaps or inconsistencies in the flow of information between them.

CASE STUDY | We Energies (Wisconsin)

Recent experience reviewing We Energies' CPCN filings illustrates these challenges in practice.

We Energies serves over 1.1 million electric customers in Wisconsin.[5] In 2024, the Company updated their load forecast and resource plan to incorporate over 2,000 MW of "new load" by the 2028/2029 timeframe. This increase coincided with an announcement from Microsoft about the construction of a new large data center facility at Mt. Pleasant. Shortly thereafter, We Energies filed two concurrent applications for CPCNs for new gas-fired generation including:

- 128 MW Paris RICE project, estimated at $279 million in capital costs
- 1,110 MW Oak Creek CT project, estimated at $1,205 million

Additionally, the Company announced plans to convert the Elm Road Generating Station from coal to natural gas in the early 2030s. Combined, these new gas-fired generation facilities comprised nearly 500,000 Dth/day of new gas demand, which would roughly double the company's existing gas demand. This prompted We Energies' affiliate company (We Energies Gas Operation or WE-GO) to propose building several new gas pipeline and storage projects, while also contracting for additional pipeline capacity from a third-party provider.

5 WE Energies, Service area map, Accessed May 14, 2026. https://www.we-energies.com/company/area

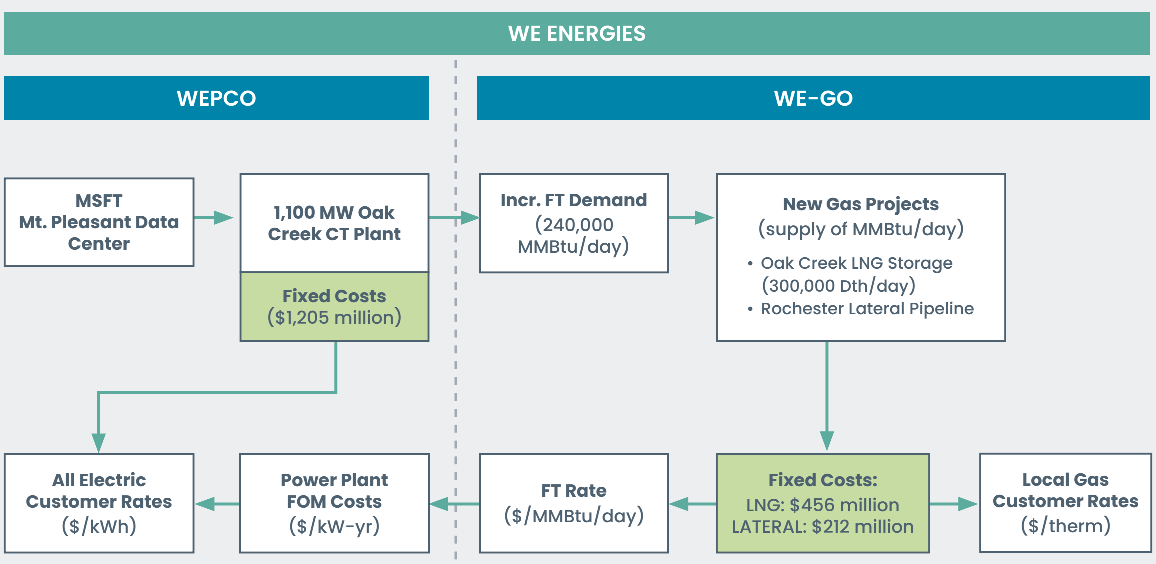
These projects included the following:[6]

- Interstate:
  - WE-GO: 300,000 Dth/day Oak Creek LNG storage facility, estimated at $456 million
  - Third party: 205,000 Dth/day ANR 2027 Expansion, long-term contract with ANR Pipeline Company (estimated costs not disclosed).
- Intrastate:
  - WE-GO-owned: Rochester Lateral Pipeline project, estimated at $212 million

Notably, initial costs for the WE-GO owned pipeline and storage projects totaled over $600 million, representing over 30% of the proposed capital spending to support generation capacity for the new data center load.

Since its initial proposal, We Energies has steadily increased its projected need for LNG storage alongside a major expansion of its CTs. The utility now plans to build 6 Bcf of new LNG storage facilities costing $1.3 billion, paired with 3,300 MW of new CT capacity valued at $5.2 billion, with all projects slated for completion through 2030.[7]

FIGURE 2. Case Study: We Energies



6 Wisconsin Electric Power Company, "Application for a Certificate of Authority to Construct a New Liquefied Natural Gas Facility and Associated Natural Gas Pipelines in Oak Creek, Wisconsin", Docket Number: 6630-CG-140, Filed April 19 ,2024, https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=498476

7 WEC Energy Group, "Energizing the Future: Investor Update," April 2026. https://s22.q4cdn.com/994559668/files/doc_presentations/2026/Apr/01/04-2026-April-Final.pdf

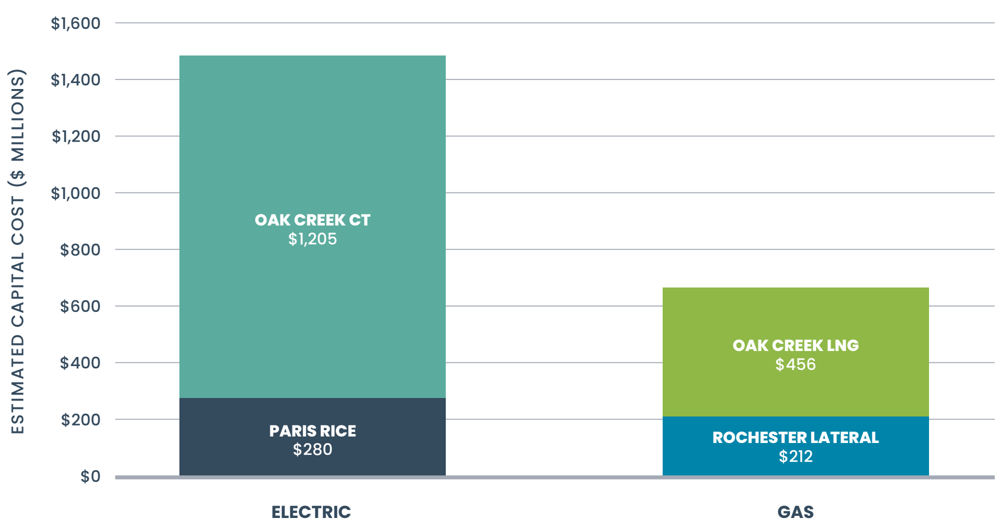
The Hidden 30%[8]

A gas generator's initial price tag tells only part of the financial story. While building a new plant requires significant upfront capital, supporting gas transmission infrastructure — such as pipelines, compressor stations, LNG storage facilities, and firm transportation contracts can quietly add hundreds of millions in fixed pipeline expenses. Even more significant are the long-term, ongoing fuel costs, which routinely account for the vast majority of a gas plant's lifetime operating expenses. An exclusive focus on the power plant costs risks losing sight of investments in supporting gas infrastructure projects, that are still significant nonetheless.

In the WEPCO case study, initial costs for the associated Rochester lateral pipeline and Oak Creek LNG storage projects totaled over $600 million, representing over 30% of the proposed capital spending to support generation capacity for a new data center (Figure 3).

FIGURE 3.

Cost Comparison Case Study: We Energies

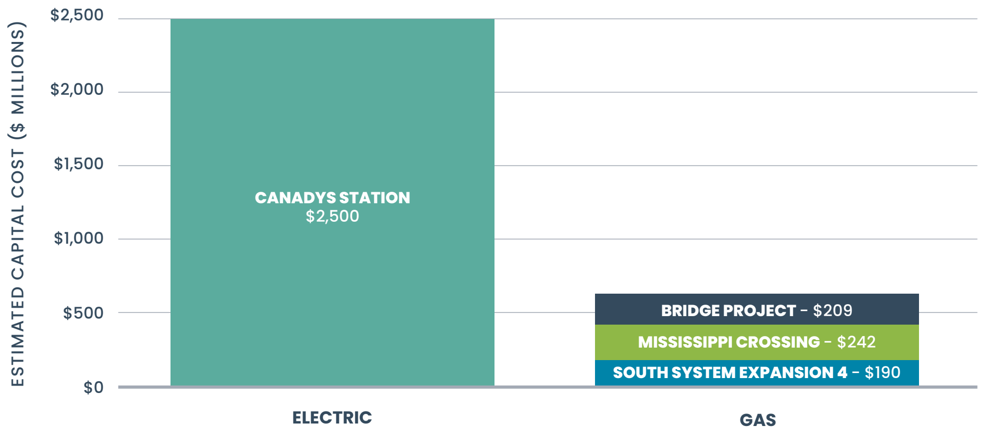


8 For simplicity, 30% is suggested here as an indicative value based on CEG's observations. However, the costs of supporting gas infrastructure likely range between 10-50% depending on the project specific details.

Case studies from other utilities also illustrate the relative costs between new generation for the electric system and gas system costs. Santee Cooper, the largest electric utility in South Carolina, is planning a 998 MW natural gas expansion at their jointly-owned Canady's Station power plant. This new electric supply is supported by a corresponding $5.6 billion investment in gas transmission infrastructure developed entirely by Kinder Morgan subsidiaries. As shown in Figure 4, the estimated cost of gas infrastructure supporting the Canadys Station plant comprised about 25% of the total cost.

FIGURE 4.

Cost Comparison Case Study: Santee Cooper's Share of Canadys Station



A Nationwide Rush to Gas

Gas Transmission Projects are Widespread and Driven by New Large Loads

New power plants being proposed to meet growing electric demand are increasingly being proposed in conjunction with new gas infrastructure projects designed to increase deliverability and fuel security. While in many cases the gas projects are not part of the exact same project proposal, they are very clearly related and often proposed in close proximity and time to the new power plant projects.

As described in the Case Study above, We Energies recently proposed development of the Oak Creek LNG storage facility to provide an additional 300,000 Dth/day of gas deliverability, to support the addition of over 1,100 MW of new gas generation capacity at the Oak Creek power plant. Similarly, in North Carolina, Duke Energy is proposing new LNG storage capacity to support the development of several new natural gas combined cycle plants that it has proposed as part of its 2025 Carolinas Resource Plan.

Table 2 lists other examples of gas infrastructure projects recently proposed to support new power generation — demonstrating that the rush to gas is occurring across the United States, largely in response to new large loads. Georgia Power's demand increase, for example, is driven predominantly by data center load growth, estimated at approximately 95% of total new load.[9]

TABLE 2. Case Studies of New Gas Transmission Projects

UTILITY	NEW GAS TRANSMISSION PROJECTS	INCREMENTAL ADDITIONS (DTH/DAY)	COST
WE Energies (WI)	Rochester Lateral	N/A	$212 M
	Oak Creek LNG	300,000	$456 M
	ANR 2027 Expansion	205,000	N/A
Dominion Energy (VA)	Brunswick and Greensville LNG	500,000*	$547 M
	Southside Expansion Project I	250,000	$275.7 M
	Southside Expansion Project II	250,000	$190.8 M
Santee Cooper (SC)	Mississippi Crossing	2,100,000**	$1.7 B (Total)
	South System Expansion 4	1,300,000**	$3.5 B (Total)
	Bridge Project	300,000	$431 M
Georgia Power (GA)	Southeast Supply Enhancement Project	50,000	Not Provided
	South System Expansion 4	230,000 to 460,000	
	Dalton, Bowen & Wansley, & Macintosh Gas Laterals	130,000	
Xcel Energy Colorado (CO)	Speer Canal Project	150,000	$42.7 M
	3 Pipeline Replacements		$5.2 M (Total)
Duke Energy Carolinas (NC & SC)	Southeast Supply Enhancement Project	1,000,000	Not provided
	Southgate Project	250,000	
	LNG storage for CC4 and CC5	N/A	Not public
LG&E/KU (KY)	Mill Creek 5 Lateral	98,208	$361 M in FT costs, 3% of proj. for laterals and compressors
	Mill Creek 5 Compressor	98,208	
	Brown 12 Compressor	N/A	

**2 BCF Storage*

*** Represents total capacity, incremental value not available*

9 Southern Environmental Law Center, GPC gas request fact sheet V3, November 2025. https://www.selc.org/wp-content/uploads/2025/12/GPC-gas-request-fact-sheet.pdf

For some gas utilities or pipeline operators, firm delivery requests from new power generation have significantly overwhelmed those from other types of customers. For example, in 2024 We Energies Gas Operations received requests to increase its firm deliverability by 85% due to 3 newly proposed gas power plants. This was compared to just a 4% increase due to estimated growth from its existing customer base over the same period. As another example, 72% of the proposed 1.32 million Dth/day South System Expansion 4 Project is contracted through precedent agreements for power generation.[10] Duke Energy Carolinas executed agreements with Transco for 1 million Dth/day of interstate FT natural gas capacity rights on the SSE project and with MVP for 250,000 Dth/day of FT rights on the Southgate project. These additions already reflect an increase of 280% of prior FT commitments, and are intended to support both the existing fleet and three of the five proposed CCs. Most of the new gas additions are primarily driven by the expected growth in large load customers. Duke is proposing LNG storage to provide fuel security to the other two CCs.

10 Southern Natural Gas Company, L.L.C. and Elba Express Company, L.L.C., Docket No. CP25-517, "South System Expansion 4 Project: Application for a Certificate of Public Convenience and Necessity to Construct, Own, Operate, Maintain, and Abandon Pipeline Facilities", Federal Energy Regulatory Commission, pg.6, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250703-5175&optimized=false&sid=74c15525-80be-4652-a128-58b146120700

Solutions

Improving Transparency, Ensuring Affordability, and Aligning Incentives

Improving Data Transparency

The U.S. presently lacks a comprehensive and detailed set of public data and information on the current state of the gas transmission network in a form that is useful to electricity system planners. Such information would undoubtedly be useful to public utility commissioners, intervenors, and other stakeholders as they evaluate utility proposals for new gas generation additions. This would enable more sound decision-making that considers the full set of costs and risks posed by new gas power plant additions as described above. This report is a first step in bridging that gap, and is part of a larger collaborative effort being undertaken by GridLab and CEG.

This research aims to improve transparency around the relationship between electric system planning and natural gas transmission infrastructure. As demonstrated by the case study findings, there is inconsistency that reduces transparency due to:

- Lack of standardized gas infrastructure planning documents or CPCNs.
- Treatment of cost information, which is considered confidential in many filings.
- Lack of clear delineation of FT rights for specific gas units (e.g. sometimes rights are secured for existing and/or future units).

Additional data transparency and standardization would help electric system planners and regulators assess where gas system costs and risks may be most acute and where alternatives are warranted. Done well, this improved visibility into the gas-electricity nexus will help ensure the system is right-sized, producing a more affordable and equitable energy system.

Ensuring Affordability: Who pays the cost for new gas infrastructure?

While it is clear that many new gas infrastructure projects are being driven by large load additions (e.g., data centers), it is unclear exactly how the costs of these gas infrastructure projects will ultimately be shared between new large loads and existing customers. This raises new affordability concerns mirroring those recently surfaced for new generation projects supporting large loads.

Increasingly, jurisdictions are seeking to identify the incremental power generation needs, and associated costs, to serve new large customers (e.g. data centers) and to ensure those customers "pay their fair share" of those new power plant costs. In some cases, the incremental generation and associated costs are explicitly identified through a Large Load Tariff or an Energy Service Agreement between the large customer and the electric utility. However, such Energy Service Agreements are often limited to the incremental power system costs and do not typically include any incremental gas system-related costs.

In theory, new large load customers might pay for these incremental costs through future gas transmission rates. However, this assumes that future gas transmission rates will be perfectly designed to capture the impact of new large load customers with no spillover.

In CEG's view, there is a risk that some of those new gas project costs will be borne by existing gas or electric customers. Costs for new gas transmission projects would generally be recovered through FT rates that are charged to the electric utility as a gas customer (though not necessarily tied to a specific power plant). These FT costs are ultimately passed on to electric retail customers, often as part of the fuel component of the retail bill.

However, depending on the pace and magnitude of the large load increase, some of the higher FT costs might instead be borne by other retail electric customers. It is also possible that increased competition for natural gas supply will lead to upward pressure on prices. Depending on how the FT rates are set, existing gas customers may also experience cost increases.

To address electric affordability concerns, best practices have begun emerging to ensure that large loads pay their fair share of incremental generation costs. These practices could extend to the gas infrastructure costs as well.

Aligning Incentives: Tackling Capital Bias

It has long been established in regulatory economics that monopoly utilities under cost of service regulation have a capital bias that incentivizes them to pursue utility-owned capital projects, even if this increases customer costs.

For some investor-owned utilities, a common holding company exists that owns both the electric and gas utilities. In these instances the inherent capital bias may be exacerbated by the prospect of incremental investment opportunities in the gas system which increase the incentive for utilities to pursue gas-fired generation over alternatives. Gas generation would afford the opportunity to simultaneously invest in both new power generation projects and new gas transmission projects. For some utilities, this may increase the attractiveness of gas generation projects relative to more affordable alternatives.

Several of our case studies, including WE Energies in Wisconsin, Duke Energy in the Carolinas, LG&E/KU in Kentucky, Xcel Energy in Colorado, and Southern Company in Georgia, involve utilities whose parent companies also own the gas infrastructure being built to serve new generation. This common holding company structure can create conflicting incentives between maximizing investment opportunities across affiliates and minimizing the total cost borne by customers, including the cost of new gas infrastructure. Recognizing where these conflicts may arise can help regulators focus their oversight accordingly."

Conclusions and Recommendations

This report marks the first phase (Phase 1) in a multi-phase collaborative project between GridLab and Current Energy Group to investigate the Hidden Cost of Gas infrastructure on electric customers. The purpose of this Phase 1 effort was to explore several preliminary case studies and begin developing a framework for future research. Even within this limited set of case studies several key trends have become apparent.

Below is a summary of six key findings, which CEG intends to continue exploring and validating in future Phases of research:

1. Power generation needs are an increasingly large fraction of interstate gas pipeline demand.
2. New gas-fired power plants are often now being proposed in tandem with corresponding gas infrastructure projects.

3. New gas transmission projects are a major component of utilities' overall fixed costs (e.g., capital investment or long-term contract) supporting new power delivery.
4. Assumptions for gas transmission costs used in electric system modeling are relatively simplistic and may be underestimated.
5. Electric utilities directly pass through the costs and risks of gas transmission projects to their retail customers.
6. It is unclear how the costs of the new gas transmission projects driven by new large loads will ultimately be shared between new large loads and existing customers.

As the electric and gas systems evolve over the coming decade, CEG expects these issues will only grow in importance as utility stakeholders confront the significant volume of gas transmission projects needed to support new gas power generation. These projects present risks to electricity customers in terms of incremental fixed costs (i.e., "hidden costs of gas") that may not be fully considered in the electric planning process. However, to the extent alternatives to gas are considered, those risks can be minimized.

Taken together, these findings also point to a practical near term agenda for regulators, utilities, and stakeholders to better capture the full costs, risks, and reliability implications of new gas generation. CEG recommends that regulators and policymakers expeditiously take the following actions:

Recommendations

1. Ensure that regulators align the planning and approval processes for major gas and electric projects (e.g., timing of CPCN cases) to ensure that the full cost of gas transportation and storage are considered in the evaluation of new generation resources.
2. Create a unified gas-electric reliability modeling framework so planners and regulators make resource decisions that reflect the full reliability value and cost of new gas generation. Use integrated assumptions for:
   - Fuel deliverability
   - Firm transportation requirements
   - Storage needs
   - Outage risk
   - Extreme-weather performance
3. Require a unified cost test for new gas generation that combines plant CapEx with all associated gas-system costs, including laterals, compression, storage, and firm transportation before approval, so regulators and stakeholders can compare gas against non-gas alternatives on a true all-in basis.

4. Build a standardized public database of gas infrastructure projects linked to new power generation, with consistent reporting of project scope, capacity, cost, contracting structure, affiliate relationships, and cost recovery pathway to improve transparency and enable cross utility benchmarking. (This is Phase 2 of this CEG/GridLab study).
5. Establish cost and risk allocation rules that ensure new large loads bear the incremental electric and gas infrastructure costs they trigger, while protecting existing customers from subsidizing long-lived fuel infrastructure and stranded-asset risk.

As this report has demonstrated, there is an urgent and widespread need to better document the costs and risks associated with new gas transmission projects in a manner that is useful for power sector analysts. Timely data presented in a consistent format will be critical towards building this body of knowledge and conducting additional research. To that end, CEG and GridLab intend to build upon the initial set of case studies by compiling a more comprehensive public database (consistent with the recommendation above). This database will aim to compile public information quantifying the costs and technical parameters of gas transmission infrastructure associated with new gas-fired power plants.

As this information is being compiled, CEG will also be conducting additional research and analysis to better inform regulators, policy-makers, and other key stakeholders of emerging trends occurring in the intersection of the electric and gas systems. We welcome participation of other stakeholders in developing this information by providing project specific details or general feedback by contacting Jordan Ahern: jahern@currentenergy.group.

For press or media inquiries related to this report, please contact media@currentenergy.group.

Disclaimer

This report was prepared by Current Energy Group (CEG) for GridLab. It is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the author using currently available information and does not necessarily reflect those of any other entity associated with this work.

Appendix A.
Case Study Details

To examine the hidden costs of gas infrastructure in practice, we reviewed seven utility case studies from across the country, each representing a utility with planned new gas generation and associated fuel delivery investments. For each case study, we analyzed publicly available regulatory filings — including IRPs, CPCN applications, FERC certificate proceedings, and gas infrastructure plans — to identify and quantify the gas transmission costs associated with new generation proposals. These case studies form the evidentiary basis for the key findings presented in this report, and collectively illustrate the scale, complexity, and limited transparency of gas infrastructure costs as they relate to new power generation.

1 | Wisconsin Electric Power Company

Planned New Gas Generation

Incremental firm gas demand (Dth/day) for specific units is held confidential in most (though not all) cases but can be estimated. Some utilities also publicly report system-wide firm gas demand & supply (e.g., WE Energies).

In 2024, WE Energies updated its load forecast and resource plan to incorporate over 2,000 MW of "new load" by the 2028/2029 timeframe. This increase coincided with an announcement from Microsoft about the construction of a new large data center facility at Mt. Pleasant. Shortly thereafter, We Energies filed several concurrent CPCN applications for new gas generation including:

- 128 MW Paris RICE project, estimated at $279 million in capital costs
- 1,110 MW Oak Creek CT project, estimated at $1,205 million

TABLE 3. New Gas Generation Additions for WEPCO

NEW GAS GENERATION ADDITIONS	IN-SERVICE DATE	MW CAPACITY	PEAK GAS DEMAND (DTH/DAY)	COST	GAS PROVIDER
Paris RICE[11]	8/2027	128	22,000	$279M	WE-GO
Elm Road GS (Coal Conversion)[12]	2028	0 incr. Capacity	215,000	$132M	WE-GO
Oak Creek CTs[13]	8/2028	1,110	240,000	$1,205	WE-GO

New Gas Transmission Infrastructure

Additionally, the Company announced plans to convert the Elm Road Generating Station from coal to natural gas in the early 2030s. Combined, these new gas generation facilities comprised nearly 500,000 Dth/day of peak gas demand. This prompted We Energies' affiliate company (We Energies Gas Operation or WE-GO) to propose building several new gas pipeline and storage projects, while also contracting for additional pipeline capacity from a third-party provider. These projects included the following:

- Interstate:
  - WE-GO: 300,000 Dth/day Oak Creek LNG storage facility, estimated at $456 million
  - Third party: 205,000 Dth/day ANR 2027 Expansion, long-term contract with ANR Pipeline Company
- Interstate:
  - WE-GO-owned: Rochester Lateral Pipeline project, estimated at $212 million

11 PSC of WI Docket 6630-CE-316, https://psc.wi.gov/Pages/CommissionActions/CasePages/ParisGeneration.aspx

12 WPSC Docket 5-CE-161, https://apps.psc.wi.gov/APPS/dockets/content/detail.aspx?id=5&case=CE&num=161

13 WPSC Docket 6630-CE-317, https://apps.psc.wi.gov/APPS/dockets/content/detail.aspx?id=6630&case=CE&num=317

Table 2-2: Forecasted Firm Requirement and Resources, WE-GO Lakeshore/Western[4]

Firm Deliverability Requirement		Dth/day	Firm Resources	Dth/day
2023-2024 Peak Day Estimate		558,785	Pipeline Contracts	476,473
Estimated Growth (1% annual)		22,689	Bluff Creek LNG	100,000
Customer Requests:	Paris RICE	22,000	ANR 2027 Expansion	205,000
	ERGS	215,000	Oak Creek LNG	300,000
	Oak Creek CT	240,000		
2027-2028 Point Estimate		**1,058,474**	2027-2028 Supply Resource	**1,081,473**
			Reserve Margin	**2.17%**

New gas plant demand

New gas transmission projects

Source: Wisconsin Electric Power Company, "Application for a Certificate of Authority to Construct a New Liquefied Natural Gas Facility and Associated Natural Gas Pipelines in Oak Creek, Wisconsin", Docket Number. 6630-CG-140, Filed April 19 ,2024, https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=498476

Notably, initial costs for the WE-GO owned pipeline and storage projects totaled over $600 million, representing over 30% of the proposed capital spending to support generation capacity for the new data center load.

TABLE 4. New Gas Transmission Projects for WEPCO

NEW GAS TRANSMISSION PROJECTS	OWNER	INTER/ INTRA-STATE	PEAK GAS DEMAND	COST	SOURCES
Rochester Lateral	We-GO	Intrastate	Redacted	$212M	WPSC Docket 6630-CG-139
Oak Creek LNG	We-GO	Interstate	300,000[14]	$456M[15]	WPSC Docket 6630-CG-140
ANR 2027 Expansion	Third party serving We-GO	Interstate	205,000[16]		

Since its initial proposal, WE Energies has reported that its need for LNG storage facilities has continued to grow, with corresponding expansion of its planned CT fleet. Currently, 6 Bcf (i.e., $1.3 billion) in new LNG facilities are planned through 2030, corresponding to a CT expansion of 3,300 MW (i.e., $5.2 billion) over the same timeframe.[17]

14 WI PSC Docket 6630-CG-140, DocID:498476, Table 2-2,

15 WI PSC Docket 6630-CG-140, DocID:498476, Page 1-10

16 WI PSC Docket 6630-CG-140, DocID:498476, Table 2-2,

17 WEC Energy Group, Energizing the Future: Investor Update, April 2026. https://s22.q4cdn.com/994559668/files/doc_presentations/2026/Apr/01/04-2026-April-Final.pdf

Data Availability

The WEPCO case study is among the most data-rich in this analysis, owing in large part to the Wisconsin PSC's structured certificate process. CPCN filings for both the Paris RICE and Oak Creek CT projects (Dockets 6630-CE-316 and 6630-CE-317) provide clear unit-level capital cost estimates, sizing, and gas provider identification. Critically, the Wisconsin PSC's certificate process for gas infrastructure — separate from the electric CPCN process — required WE-GO to file standalone applications for both the Rochester Lateral and Oak Creek LNG facility (Dockets 6630-CG-139 and 6630-CG-140), with itemized capital cost estimates publicly available for both projects. This level of gas-side transparency is uncommon across the case studies reviewed and reflects a strength of Wisconsin's regulatory framework in making the relationship between new generation and supporting gas infrastructure legible to regulators and the public.

Some limitations remain. Incremental firm gas demand figures for specific generating units are held confidential in most filings, and the cost and contractual terms of the third-party ANR 2027 Expansion agreement are not available in the public record. Additionally, as WE Energies has continued to revise its load forecast and expand its planned CT fleet, the total scope of planned gas infrastructure investment has grown significantly since initial filings — underscoring the importance of ongoing monitoring rather than reliance on point-in-time filings alone.

2 | Dominion Energy Virginia

Dominion's most recent filed CPCN for new gas-fired generation includes the Chesterfield Energy Reliability Center, a 944 MW generating station consisting of four CTs. No incremental FT commitment or associated fuel security cost has been identified for this project. However, it is worth noting that Dominion recently got approval to amend the CPCNs for the Brunswick County Power Station and the Greensville County Power Station to construct and operate a LNG production, storage, and regasification facility and related transmission facilities to support the units' operations and improve the reliability of the company's fleet. For the fuel supply and operation of these units, lateral pipelines and other transmission projects had been previously approved and are summarized in Table 5.

TABLE 5. New Gas Transmission Projects for Dominion Energy Virginia

NEW GAS TRANSMISSION PROJECTS	OWNER	INTER/ INTRA-STATE	PEAK GAS DEMAND (DTH/DAY)	COST	SOURCES
Brunswick and Greensville LNG	Dominion	Intrastate	500,000 (2BCF total storage)	$547M	PUR-2024-00096 (SCC)
Virginia Southside Expansion Project I*	Transcontinental Gas Pipe Line Company, LLC ("Transco")	Intrastate (primarily)	270,000 (250,000 for power plant)	$275.7M	CP13-30 (FERC)
Virginia Southside Expansion Project II**	Transcontinental Gas Pipe Line Company, LLC ("Transco")	Intrastate (primarily)	250,000	$190.8M	CP15-118 (FERC)

3 | Santee Cooper

Planned New Gas Generation

Santee Cooper faces one of the most dramatic planned gas expansions among the utilities examined, with approximately 2,650 MW of new gas capacity planned between 2028 and 2035, a roughly 250% increase over its current 1,063 MW fleet. The scale of this expansion, concentrated around a single large jointly-owned facility at Canadys Station, is supported by a corresponding $5.6 billion pipeline supply chain developed entirely by Kinder Morgan subsidiaries.

TABLE 6. Santee Cooper: Proposed New Gas Generation Projects

NEW GAS GENERATION ADDITIONS	IN-SERVICE DATE	MW CAPACITY	PEAK GAS DEMAND (DTH/DAY)	COST	GAS PROVIDER
Rainey CC (Power Block 1 upgrade)[18]	Winter 2028	520->570	No Value, 100% CF Calc: 97,210	N/A	Carolina Gas Transmission
Rainey CT (Power Block 2 upgrade)[19]	Planned 2028	630->829	No Value, 100% CF Calc:226,237	N/A	Carolina Gas Transmission
LM6000 CTs (x2)[20]	Planned 2028	107MW (53MW x2)	No Value, 100% CF Calc:24,468	$270M ($2,528/kW)	N/A
Canadys Station Joint NGCC (SC Portion)[21]	Planned 2033	998	No Value, 100% CF Calc:148,167	$2.5B	3 Kinder Morgan Subsidiaries
Planned NGCC[22]	Planned 2035	1,296	No Value, 100% CF Calc:192,409	$3.2B	N/A
Total Capacity (MW)		**2,650**			

The near-term additions, Rainey Station upgrades, and two LM6000 CTs at Winyah, require no apparent new pipeline infrastructure, with gas supply running through existing Carolina Gas Transmission interconnects. The Canadys Station joint NGCC, planned for 2033 and shared roughly 50/50 with Dominion Energy, is the centerpiece of near-term expansion at 998 MW and $2.5B for Santee Cooper's share. A second NGCC of 1,296 MW appears in the 2025 IRP Update as a 2035 planning estimate, with no CECPCN yet filed.

18 Santee Cooper, Integrated Resource Plan 2025 Update, p.22, https://www.santeecooper.com/About/Integrated-Resource-Plan/presentations/Santee-Cooper-2025-IRP-Update.pdf

19 Santee Cooper, Integrated Resource Plan 2025 Update, p.22, https://www.santeecooper.com/About/Integrated-Resource-Plan/presentations/Santee-Cooper-2025-IRP-Update.pdf

20 PSC of SC Docket No. 2025-246-E, https://dms.psc.sc.gov/Web/Dockets/Detail/119469

21 PSC of SC Docket No. 2025-323-E, https://dms.psc.sc.gov/Web/Dockets/Detail/119564

22 Santee Cooper, Integrated Resource Plan 2025 Update, p.22, https://www.santeecooper.com/About/Integrated-Resource-Plan/presentations/Santee-Cooper-2025-IRP-Update.pdf

New Gas Transmission Infrastructure

TABLE 7. Santee Cooper: New Gas Transmission Projects

NEW GAS TRANSMISSION PROJECTS	IN-SERVICE DATE	OWNER	INTER/ INTRA-STATE	PEAK GAS DEMAND	COST	SOURCES
Mississippi Crossing (MSX)	Q4 2028	Tennessee Gas Pipeline Co., LLC	Interstate	2.1 Bcf/day	Kinder Morgan's total investment cost is $1.7B	Randall Testimony, Docket 2025-323-E
South System Expansion 4 (SSe4)	Two Stages: Q4 2028 / Q4 2029	Southern Natural Gas Co., LLC & Elba Express Co., LLC	Interstate (Brownfield Looping Expansion)	1.3 Bcf/day	Kinder Morgan's total investment cost is $3.5B	Randall Testimony, Docket 2025-323-E
Bridge Project	Q2 2030	Elba Express Co., LLC	Interstate	.3 BCf/day	Kinder Morgan's total investment cost is $431M	Randall Testimony, Docket 2025-323-E

All three pipeline projects serve Canadys sequentially, with full gas delivery dependent on the Bridge Project reaching commercial operation in 2030. Mississippi Crossing (Q4 2028), the furthest along in the regulatory process with a FERC certificate application filed in June 2025, provides 2.1 Bcf/day of upstream supply at $1.7B in total KM investment, an upsize from the original 1.5 Bcf/day and $1.4B announced at FID in December 2024. South System Expansion 4 follows in two phases through Q4 2029, adding 1.3 Bcf/day through brownfield looping at $3.5B and described in its FERC filing as fully subscribed. The Bridge Project, the final link at 0.3 Bcf/day and $431M, has not yet entered FERC pre-filing. All capacity and cost figures reflect total project design parameters; contracted volumes and transmission rates attributable to Santee Cooper are confidential under standard FERC practice.

Data Availability

CPCN filings are the most productive source for generation cost and sizing data in this case study. Projects outside the CPCN process, such as the Rainey upgrades, leave cost and gas demand figures effectively inaccessible from public sources. On the pipeline side, FERC certificate applications and developer disclosures provided reliable cost and design detail for the two projects that have reached that stage; the Bridge Project remains documented only through the Randall testimony in the Canadys CECPCN docket. Gas transmission rates and Santee Cooper's contracted volumes are confidential and unavailable from public filings.

4 | Georgia Power

Planned New Gas Generation

In 2025, Georgia Power updated its resource plan to incorporate nearly 10 GW of new power capacity before the Public Service Commission (PSC), including 3,692 MW of new gas generation across five combined cycle (CC) units at three sites. This increase is driven predominantly by data center load growth, estimated at approximately 95% of new demand.[23] Shortly thereafter, Georgia Power filed applications for the following new gas generation projects, summarized in Table 4:

- 1,482 MW Bowen Units 7 & 8, with estimated peak gas demand of approximately 249,000 Dth/day
- 1,453 MW Wansley Units 10 & 11, with estimated peak gas demand of approximately 244,100 Dth/day
- 757 MW McIntosh Unit 12, with estimated peak gas demand of approximately 127,000 Dth/day

Capital costs for all three projects are redacted in public filings, though estimates derived from available data suggest approximately $3.7 billion for Bowen, $3.6 billion for Wansley, and $1.8 billion for McIntosh. Gas supply for the Bowen and Wansley units will be provided via Transco, while McIntosh will be served by Southern Natural Gas. In addition to these company-owned units, Georgia Power is also requesting approval to purchase power from additional gas-burning plants. Firm transportation contracts indicate that approximately 110,000 MMBtu/day is being acquired per new CC unit to meet system requirements.

TABLE 8. Georgia Power (GA): Proposed New Gas Generation Projects

NEW GAS GENERATION ADDITIONS	IN-SERVICE DATE	MW CAPACITY	PEAK GAS DEMAND (DTH/DAY)	COST	GAS PROVIDER
Bowen Units 7 & 8	5/1/2030	1,482 MW	Redacted (249,000)	Redacted (~$3.7 B)	Transco
Wansley Units 10 & 11	5/1/2030	1,453 MW	Redacted (244,100)	Redacted (~$3.6 B)	Transco
McIntosh Unit #12	11/1/2030	757 MW	Redacted (127,000)	Redacted (~$1.8 B)	Southern Natural Gas
Total New Generation		**3,692 MW**			

23 Southern Environmental Law Center, GPC gas request fact sheet V3, November 2025. https://www.selc.org/wp-content/uploads/2025/12/GPC-gas-request-fact-sheet.pdf

New Gas Transmission Infrastructure

To support the new gas generation projects, Georgia Power has contracted for substantial new firm transportation capacity. These projects are being procured across two primary pipeline systems: Transco and Southern Natural Gas (SNG).

Firm Transportation (FT)

Georgia Power has secured, or is in the process of securing, four tranches of new firm transportation capacity to serve the Bowen, Wansley, and McIntosh units:[24]

- 400,000 MMBtu/day via Transco for Bowen & Wansley (in-service 11/1/2027), through the Southeast Supply Enhancement (SSE) Project (FERC Docket CP-25-10-000)
- 50,000 MMBtu/day via Sequent Energy (through Transco) for Bowen & Wansley (in-service 1/1/2025), utilizing existing infrastructure with no new construction required
- 230,000 MMBtu/day via Transco for Bowen & Wansley via a new lateral off the Dalton mainline (in-service 11/1/2029), with potential to expand up to 460,000 MMBtu/day to serve additional future units
- 130,000 MMBtu/day via SNG for McIntosh (in-service 11/1/2029), as part of the South System Expansion 4 (SS4) Project (FERC Docket CP-25-517-000)

Costs for all FT arrangements are redacted in public filings. Per Georgia Power's own filings, approximately 110,000 MMBtu/day is being contracted per new CC unit to meet system gas requirements.

Pipeline Laterals

New pipeline laterals are required at both the Bowen and Wansley sites to connect the generating units to the Dalton mainline. These laterals will be owned and operated by Transco. A FERC certificate application for this infrastructure is anticipated but had not yet been filed at the time of this analysis. A lateral for McIntosh associated with the SS4 project may also be required, though this has not been confirmed in public filings. All lateral cost information is redacted.

24 Georgia Power Company, "Docket No. 56298 & 56310, Certification of 2029-2031 All-Source RFP & 2028-2031 Supplemental Resources", STF-PIA Data Request Set No. 3

Compressor Stations

The increased firm transportation volumes associated with the SSE Project will require modifications to two existing Transco compressor stations in Georgia:

- Compressor Station 125 in Walton County, GA: piping modifications to make the station bidirectional
- Compressor Station 120 in Henry County, GA: regulator installation and piping modifications to make the station bidirectional

These modifications are part of the broader SSE Project and are not standalone new compressor builds. Their costs are likely included within the firm transportation arrangement and are not separately itemized in public filings.

Summary

TABLE 9. New Gas Transmission Projects for Georgia Power

NEW GAS TRANSMISSION PROJECTS	IN-SERVICE DATE	OWNER	INTER/ INTRA-STATE	PEAK GAS DEMAND (MMBTU/DAY)	COST	SOURCES
Bowen & Wansley laterals (Yates Units 8-10 or other new CCs, Portion of SSe)	11/1/2027	Transco	Interstate	400,000 MMBtu/Day	Redacted	FERC: CP-25-10-000 (Southeast Supply Enhancement ("SSE") expansion project
Bowen & Wansley Supplemental Supply	1/1/2025	Sequent Energy (via Transco)	Interstate	50,000 MMBtu/Day	Redacted	N/A, No construction
Dalton Gas Lateral (for 2 Bowen CC Units Supply, up to 2 future)	11/1/2029	Transco	Interstate	230,000 MMBtu/Day (up to 460k for 2 future units)	Redacted	FERC Docket ID TBD.
McIntosh gas lateral (Portion of South System 4 ("SS4") Project)	11/1/2029	Southern Natural Gas	Interstate	130,000 MMBtu/Day	Redacted	FERC CP-25-517-000

Data Availability

Georgia Power's CPCN filing in Docket No. 56298 before the Georgia PSC is the primary structured source for generation project details, including unit sizing and gas provider identification. However, capital cost figures for all three generation projects — Bowen, Wansley, and McIntosh — are fully redacted in public filings, limiting the ability to assess total project economics from public sources alone.

For gas transmission infrastructure, cost data is similarly unavailable. Lateral costs are documented in Georgia Power's Application for Certification in Docket No. 56298, but all cost figures are redacted. Firm transportation contract terms, including reservation rates and contracted volumes attributable to specific units, are treated as confidential under standard FERC practice and are not available in the public record. Compressor modification costs are not separately itemized and appear to be bundled within the broader SSE Project's FT arrangements.

The Georgia case study is therefore among the least transparent in this analysis in terms of cost data. The combination of redacted CPCN filings and confidential FT contracts means that the full capital and contractual costs of supporting Georgia Power's planned gas expansion are not readily accessible to regulators, intervenors, or the public. FERC certificate applications for the SSE and SS4 projects provide useful project-level detail on pipeline design and capacity, but do not resolve the gap in cost transparency at the utility level.

5 | Xcel Energy Colorado

Planned New Gas Generation

Xcel Energy Colorado's planned gas expansion is modest relative to other studied utilities. A single 400 MW CT addition at St. Vrain is planned for 2027, with no new CC capacity planned through 2035. Unlike most other case studies, the associated gas infrastructure needs to be met entirely through Xcel's own intrastate pipeline system, with no new interstate pipeline capacity or firm transportation agreements identified in the public record.

TABLE 10. New Gas Generation Additions for Xcel Energy CO

NEW GAS GENERATION ADDITIONS	IN-SERVICE DATE	MW CAPACITY	PEAK GAS DEMAND (SCF/DAY)	COST	GAS PROVIDER
St. Vrain Units 7 and 8[25]	2027	400	150,000,000	Redacted	Xcel

The St. Vrain addition, pursued under CPCN Proceeding No. 25A-0321E with the Colorado PUC, though capital costs are redacted in the public application and resulting decision. To support the addition, Xcel's 2025 Gas Infrastructure Plan identifies the Speer Canal Project as the primary associated infrastructure investment. Of its $42.7 million total cost, $9.7 million is directly attributable to the new generating units, with the remainder reflecting broader system needs. Three additional pipeline reinforcement and replacement projects totaling $5.2 million are also planned through 2029–2030 as general system upgrades, not tied to the St. Vrain addition.[26]

25 *Colorado PUC Proceeding No. 25A-0321E, Decision No. R26-0127 (Feb. 26, 2026).*

26 GIP, Proceeding No. 25A-0220G

TABLE 11. New Gas Transmission Projects for Xcel Energy CO

NEW GAS TRANSMISSION PROJECTS	IN-SERVICE DATE	OWNER	INTER/ INTRA-STATE	PEAK GAS DEMAND	COST	SOURCES
Speer Canal Project	2027	Xcel	Intrastate	NA	$42.7M Total cost, $9.7 of which is attributable to supporting St. Vrain generation	Proceeding No. 25A-0220G (GIP), 2026 Interim Report
Pipeline "Reinforcement" Replacement Projects (2 total)	2029-2030	Xcel	Intrastate	NA	$3.7 million ($2.1M, $1.6M)	Proceeding No. 25A-0220G (GIP), 2026 Interim Report

Data Availability

The Colorado PUC's GIP process is a strong source for gas infrastructure data, providing both total project costs and the generation-attributable share of the Speer Canal Project. This level of cost allocation specificity is relatively uncommon across the case studies reviewed. Capital costs for the St. Vrain generation project remain redacted in the CPCN filing. Gas demand is reported in the GIP in scf/day rather than the more common Dth/day; the 150,000,000 scf/day figure converts to approximately 150,000 Dth/day under standard pipeline-quality gas assumptions.

6 | Duke Energy Carolinas & Duke Energy Progress

Planned New Gas Generation

Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP), (collectively Duke Energy or Duke) filed their 2025 Carolinas Resource Plan before the North Carolina Utilities Commission on October 1st, 2025.[27] Duke's proposed near-term action plan includes 2,825 MW of incremental CT capacity by 2033 and 6,825 MW of CC capacity by 2033. Some of the proposed units have received CPCNs, others are being evaluated, while later units are treated as generic in the utility's analysis.

27 Also presented before the South Carolina Public Service Commission as an IRP Update in the 2023 IRP docket 2023-10-E.

TABLE 12. New Gas Generation Additions for Duke Energy

NEW GAS GENERATION ADDITIONS	IN-SERVICE DATE	MW CAPACITY	PEAK GAS DEMAND (SCF/ DAY)[28]	COST	GAS PROVIDER
Person County CC1	1/1/2029	1,360 MW	200,000	Redacted	Executed FT agreements with Transco (Southeast Supply Enhancement), and with Mountain Valley Pipeline, LLC (Southgate project)
Person County CC2	1/1/2030	1,360 MW	200,000	Redacted	
Anderson County CC3	1/1/2031	1,360 MW	200,000	$2,358/kW	
CC4	1/1/2032	1,360 MW	200,000	Redacted	Proposed LNG facilities
CC5	1/1/2033	1,360 MW	200,000	Redacted	
Marshall CTs (1&2)	1/1/2029	856 MW	200,000	Redacted	
Buck CTs (3&4)	1/1/2030	856 MW	200,000	Redacted	
Smith F Frame	1/1/2030	255 MW	60,000	Redacted	
CT5 & CT6	1/1/2032	856 MW	200,000	Redacted	

New Gas Transmission Infrastructure

Duke's planned generation expansion requires a substantial increase in firm gas transportation capacity. The Companies currently hold a combined long-term portfolio of approximately 447,560 Dth/day of interstate firm transportation (FT) service on Transco. Their existing peak burn requirement for the current baseload CC fleet is approximately 980,000 Dth/day. To support the existing CC fleet as well as the three first CC additions, Duke has contracted for 1,000,000 Dth/day with Transco via the Southeast Supply Enhancement (SSE) Project and 250,000 Dth/day with the Mountain Valley Pipeline (MVP) via the Southgate Project. In its 2025 Carolinas Resource Plan, Duke is proposing fuel security via LNG facilities for CC4 and CC5.

Data Availability

Capital costs for Duke's generation additions are largely redacted in public filings. Gas demand figures in the generation table are CEG estimates based on unit heat rates rather than utility-disclosed values. Firm transportation volumes are well-documented through the 2025 Carolinas Resource Plan and its appendices, providing a clear picture of the scale of new FT commitments even where cost figures are unavailable. Pipeline costs for the SSE and Southgate projects have not been publicly disclosed by Duke; FERC certificate applications for both projects would be the primary source for independent cost verification.

28 Assuming a heat rate of 6.2 MMBtu/MWh for CC units, and 9.7 MMbtu/MWh for CT units.

7 | LG&E/KU

Planned New Gas Generation

LG&E/KU operate approximately 2,743 MW of gas-fired generation capacity, consisting of 689 MW of CC capacity, and 2,054 MW of CT capacity. Currently, the companies plan to add approximately 1,980 MW of new CC capacity through 2031 across three projects.

TABLE 13. New Gas Generation Additions for LG&E+KU

NEW GAS GENERATION ADDITIONS	IN-SERVICE DATE	MW CAPACITY	PEAK GAS DEMAND (DTH/DAY)	PLANT COST	FT COSTS	GAS PROVIDER
Mill Creek 5 (CC)[29]	2027	660	98,208	$1.38 B	NA	Texas Gas Transmission
Brown 12 (CC)[30]	2030	660	98,208	$1.38 B	$15/kW-yr, or $9.9M/yr	Texas Gas Transmission and Tennessee Eastern
Mill Creek 6 (CC)[31]	2031	660	98,208	$1.42 B	$27/kW-yr, $17.8M/yr	Texas Gas Transmission

All three additions are 660 MW CC plants. Mill Creek 5 is the most immediate project, being approved in 2023 and expected to begin operation in 2027. Its capital cost estimate has grown significantly from an initial figure of approximately $0.6 billion to $0.91 billion.[32] Brown 12 and Mill Creek 6 follow in 2030 and 2031 respectively, with costs of $1.38 billion and $1.41 billion. Gas demand figures are CEG calculations based on unit heat rates; direct values were not provided in utility filings.

29 LGE KU, Mill Creek 5 Generating Unit, Accessed May 14, 2025. https://lge-ku.com/mc5

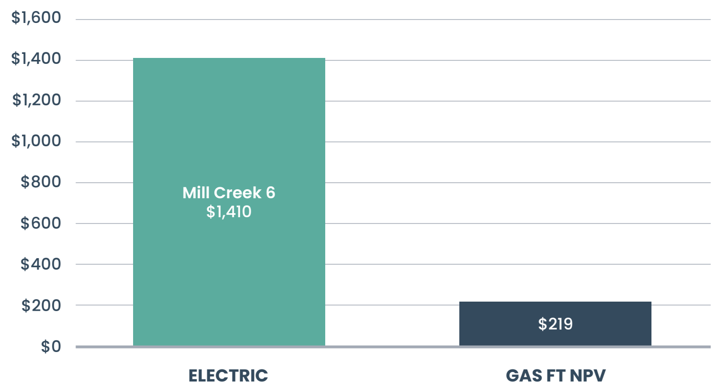
30 KY. PSC, Case No. 2025-00045, Electronic Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates, Order.

31 KY. PSC, Case No. 2025-00045, Electronic Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates, Order.

32 LGE KU, Mill Creek 5 Generating Unit, Accessed May 14, 2025. https://lge-ku.com/mc5

FIGURE 5.

Comparisons of Electric Capex and Calculated NPV of FT Costs for Mill Creek



New Gas Transmission Infrastructure

LG&E/KU's three planned CC additions require distinct gas infrastructure investments at or near each plant site. Notably, no major new interstate pipeline capacity appears to be required for Mill Creek 5 or Brown 12, as existing providers have confirmed adequate system capacity to serve both units.

For Mill Creek 5, a new short-run 16-inch gas pipeline lateral of less than a mile will connect the plant to the Texas Gas system, along with new onsite gas compression. Texas Gas has confirmed it has adequate existing capacity on its system to serve the unit without significant additional pipeline construction. Combined, gas transmission costs for Mill Creek 5 represent approximately 3% of total project cost. Similarly, Brown 12 will require new onsite compression to allow the existing pipeline to serve both the current simple-cycle turbines and the new CC unit. Gas transmission costs for Brown 12 are also estimated at approximately 3% of total project cost. The NPV of firm gas transportation costs for Brown 12 and Mill Creek 6 are calculated at $138M and $218M respectively.

Gas supply at Brown 12 will be sourced from either Texas Eastern or Tennessee Gas, both of which are currently able to serve the station. Gas supply for both Mill Creek 5 and 6 will be sourced from Texas Gas.[33]

Data Availability

KPSC CPCN dockets are the primary source for data for this case study. Notably, testimony in Case No. 2025-00045, the CPCN for Brown 12 and Mill Creek 6, among others, contained explicit firm transportation cost estimates broken out by year, a level of specificity that is uncommon across the utilities reviewed in this report and which enabled CEG's NPV calculations for those two projects. This stands in contrast to most other case studies where FT costs are either aggregated across the generation fleet, treated as confidential, or absent from public filings entirely.

33 Direct Testimony of David L. Tummonds, Case No. 2025-00045

GridLAB

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