WHY CAN'T WE BE FRIENDS?
GAS AND ELECTRICITY CAN MEET ENERGY CHALLENGES TOGETHER

Over the past year, a few state regulators have begun looking at integrating distribution system planning between electricity and natural gas utilities, often when contemplating the gas industry's future. The vital role of natural gas infrastructure in providing safe, reliable, and affordable energy service is often raised, and there seems to be a growing consensus that gas is likely to retain that role into the foreseeable future. A January 2025 white paper from the Lawrence Berkeley National Laboratory highlighted potential benefits that could be realized through cooperative planning between gas and electricity delivery utilities, including lower costs to customers and enhanced energy security, resilience, and reliability, as well as avoidance of redundancy and greater confidence in utility investment decisions.

Integrated resource planning (IRP), a concept familiar to most electric utilities, originated amid the challenges of energy scarcity and high prices in the latter half of the 20th century. Over the past two decades, IRP has expanded to include sustainability and environmental impact, particularly as climate concerns and renewable energy rose to prominence. In our view, synergies between the built-and-paid-for electricity and natural gas systems could be leveraged to support cheaper, simpler, and reliable energy delivery more effectively than a single-system approach.

This paper explores four objectives that could be achieved by integrating and leveraging the strengths inherent in each energy delivery system:

1) **Energy security, resilience, and reliability**
2) **Meeting peak loads while furthering renewable energy deployment**
3) **Keeping energy affordable**
4) **Minimizing emissions**

Background

Distribution system planning began receiving more attention over the past decade alongside issues like storm hardening, demand side management, and customer-supplied power (e.g., rooftop solar). Still, gas and electric utilities operated in parallel, each focused on supplying customers with their respective products. Even as the share of natural gas used to generate electricity has increased to about 40% of U.S. supply, the concept of electric/gas coordination or interdependence remains novel at the distribution level. Indeed, connecting more customers and growing sales volume remain key to the ability of individual utilities to spread costs and thus manage rates per kilowatt-hour or therm.

Enter decarbonization, a pursuit often conflated with an all-electric future that—in an idyllic form—would be powered entirely by carbon-free resources such as wind, solar, hydropower, and (recently) nuclear—plus a whole lot of batteries. Building on that narrative, some states embarked on a path to rapidly phase out all fossil fuel resources, including natural gas. As detailed in MCR's Investor Perspectives on Natural Gas Utilities, "gas ban" proposals drove regional uncertainty over the future of natural gas local distribution companies (LDCs), making it harder and more costly for LDCs to attract capital. In the words of one long-time utility investor, "all of a sudden, gas was evil."

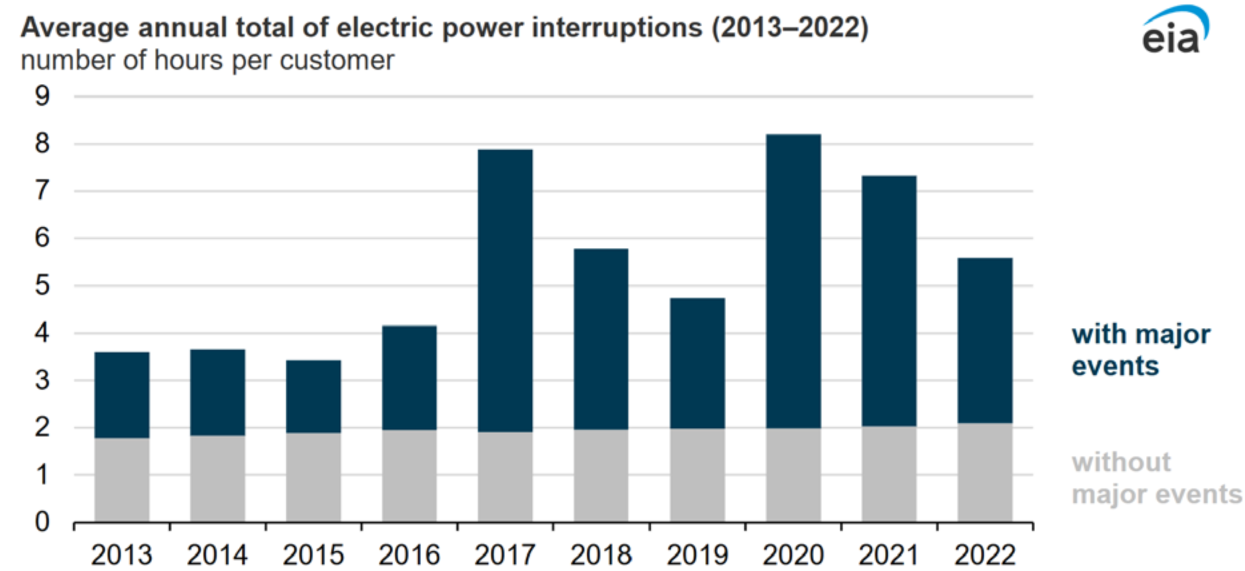
Lately, the decarbonization mantra is colliding with consumer expectations for secure, reliable, resilient, and *affordable* energy delivery. Those expectations never changed, even as meeting them has become more challenging, especially for electric utilities, due to inflation, higher financing costs, hostile weather, and accelerating demand growth. At the end of the day, utility customers purchase light, comfort, and productivity and may be less concerned with the source than with how reliable the service is and how much it costs. Choice also matters—gas vs. electric cooking comes to mind—as do environmental concerns. Let's explore the technical issues behind those needs in greater detail.

1 ENERGY SECURITY, RESILIENCE, AND RELIABILITY

Throughout their history, North American utility systems were engineered to safely and reliably deliver electricity and natural gas regardless of extreme weather, demand, or supply interruptions. Utility reliability was typically achieved through deliberate over-building, sustained by a regulatory construct that assured recovery of and a return on prudent investments.

The 21st century has posed challenges for security, reliability, and resilience. In many states, electricity deregulation eroded the underwriting of capacity and reserve margins implicit in the utility model. More recently, increased frequency and severity of weather events, shown in Figure 1, have raised the risk of outages even as technology has improved detection, response, and recovery times. At the same time, the rising wildfire risk in many states has forced preemptive electric grid shutdowns in the interest of public safety. Finally, the inherent variability of fast-growing renewable wind and solar energy, coupled with the steady attrition of older “around the clock” resources, further complicates the uninterrupted flow of energy.

Figure 1: Major Events Leading to Power Outages



Data source: U.S. Energy Information Administration, *Annual Electric Power Industry Report*

Interdependence of Natural Gas and Electricity Systems

In February 2021, a multi-day power outage affecting hundreds of thousands of customers across Texas during winter storm Uri, one of the most severe cold weather outbreaks in state history, left a death toll well over 200. After a lot of finger-pointing, multiple logistical failures across the energy system became clear, likely exacerbated by a lack of communication and understanding of gas and electricity interdependency. For example, when rotating blackouts were implemented to prevent an electricity transmission system collapse, compressor stations that move gas to power plants were blacked out as well, compounding the situation.

Risk management and contingency planning are foundational to reliability and resilience. The former is often achieved by not putting all the eggs in one basket, while the latter might be having an egg alternative. Translating those concepts to deliver a critical public good such as energy calls for multiple pathways and fuel diversity—or at least the availability of alternatives.

Viewed through that lens, better integration of the parallel electricity and natural gas distribution systems could enable provision of backup power during and after weather events, including the ability

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to "island" critical facilities and functions in a microgrid configuration. "Grid-edge" solutions could also facilitate effective deployment of recovery and restoration personnel while sustaining power not only for emergency services (e.g., hospitals, police, and fire) but also for essential commercial services such as grocery stores, gasoline stations, and pharmacies.

2 MEETING PEAK LOADS WHILE FURTHERING RENEWABLE ENERGY DEPLOYMENT

Reliability means delivering consistent performance, even when a system is stressed. Few logistical systems experience the dynamism of supply and demand seen in the case of energy, and electricity in particular. Demand changes hourly, daily, and seasonally, driven by everything from weather to economic output to the timing of sporting events. Consumers expect energy to be delivered reliably under peak conditions, and to be resilient when the unexpected happens.

Utilities have historically maintained reliability and resilience during peak loads by designing excess capacity (reserve margins) into their systems, which means building and/or contracting supply and delivery capabilities that exceed maximum expected demand. Electricity usage has historically peaked with the summer cooling load, while gas demand generally coincides with winter heating. However, the North American Electric Reliability Corporation (NERC, created to support the reliability and security of the power system) has noted a seasonal shift in its recent Winter 2024–2025 risk assessment:

> *"Winter electric load is growing in most areas. ... Serving winter load is becoming more challenging and complex as coal-fired and older natural gas-fired generators retire and are replaced by variable and energy-limited resources."*

Figure 2, adapted from NERC's assessment, shows that some of the states and regions most aggressively driving electrification actually receive "gas by wire" at times of peak demand.

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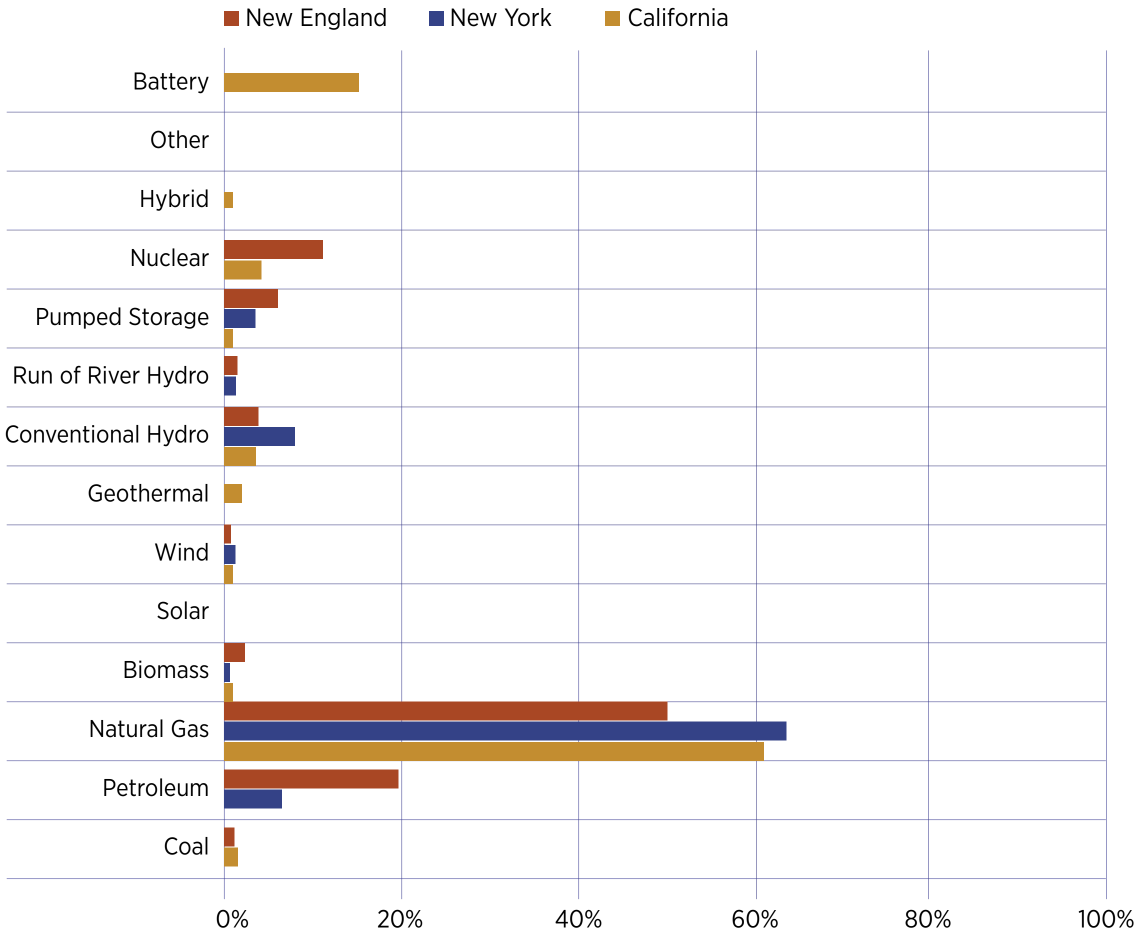
Figure 2: NERC Estimated Peak-Load Power Supply Fuel Mix



Source: NERC 2024–2025 Winter Assessment

The Pipeline Capacity Conundrum

While natural gas has clearly emerged as critical to meeting peak electricity demand, few if any electricity generators have firm contractual capacity on the natural gas pipeline system. Most of that capacity is held by gas LDCs, which understandably manage it to ensure they can meet customer demand that typically peaks in the winter. LDCs recover pipeline costs from their utility customers and release unneeded capacity into the market, typically in the summer, when it is usually directed to supply power generators.

Importantly, pipelines are built to serve contracted capacity and, unlike the bulk power system, aren't designed with reserve margins. As such, the coincident winter peak demand for electricity and natural gas poses a significant challenge as rising electricity demand collides with the direct use of gas for space and water heating. As discussed below, this forces the use of higher-emitting fuel oil or kerosene to meet peak winter power demand in the Northeast. While often seen as intractable, allocation of—and payment for—critically needed pipeline capacity for generation or direct use alike might be better addressed via coordinated planning at the distribution level.

Storing Electricity

Batteries are often cited as an effective way to address the variability of renewable resources. California in particular has deployed over 10 gigawatts of typically 4-hour duration battery storage, allowing excess peak solar power production to be utilized after the sun sets (when power demand typically peaks). However, batteries don't *produce* power and can only recharge when generation supply exceeds demand. As battery deployment increases, so too does the need for both generation and transmission/distribution grid capacity to replenish storage while meeting current demand. This is particularly challenging in winter, when sunlight and solar production decline significantly.

Battery deployment is likely to accelerate as not only utilities, but also commercial and residential electricity users, seek protection from power interruptions. Leveraging smart meter intelligence to "dispatch" smaller distributed resources for short durations could alleviate stress on power grids during short-duration peak events as well as outages, including those planned for public safety reasons (e.g., wildfires). Perhaps a stretch today, but with improving technology, smaller on-site backup generators could even be called upon in similar fashion.

Addressing Variability

Renewable energy—particularly solar—is limited by daily and seasonal variations in sunlight, with 2023 average U.S. capacity factors ranging from 31% in June to around 13% in December, according to research by S&P Global. Wind capacity factors are generally higher, but far from certain. Germany—an early adopter of renewable energy—has turned to a combination of natural gas, lignite, and power imports to address an extended period of below-normal wind power production (which typically peaks during winter months) since mid-2024. PacifiCorp has become the latest U.S. utility to delay previously planned coal retirements to hedge against rising demand, even as capacity factors for those plants have fallen. This is a suboptimal solution in economic and environmental terms, but on a cold day, coming up short on power is far worse.

New England's Unintended Consequences

Despite being among the U.S. regions most actively seeking to phase it out, the New England states still derive most of their electricity from natural gas—51% last year, according to the grid operator's website. That doesn't hold true on the "peakiest" of days, however. New England's success in stopping expansion of natural gas infrastructure has led to what's shown in Figure 3. When Boston and Hartford get really cold—as during the fourth week of January 2025—carbon-heavy liquid petroleum fuels quickly become the

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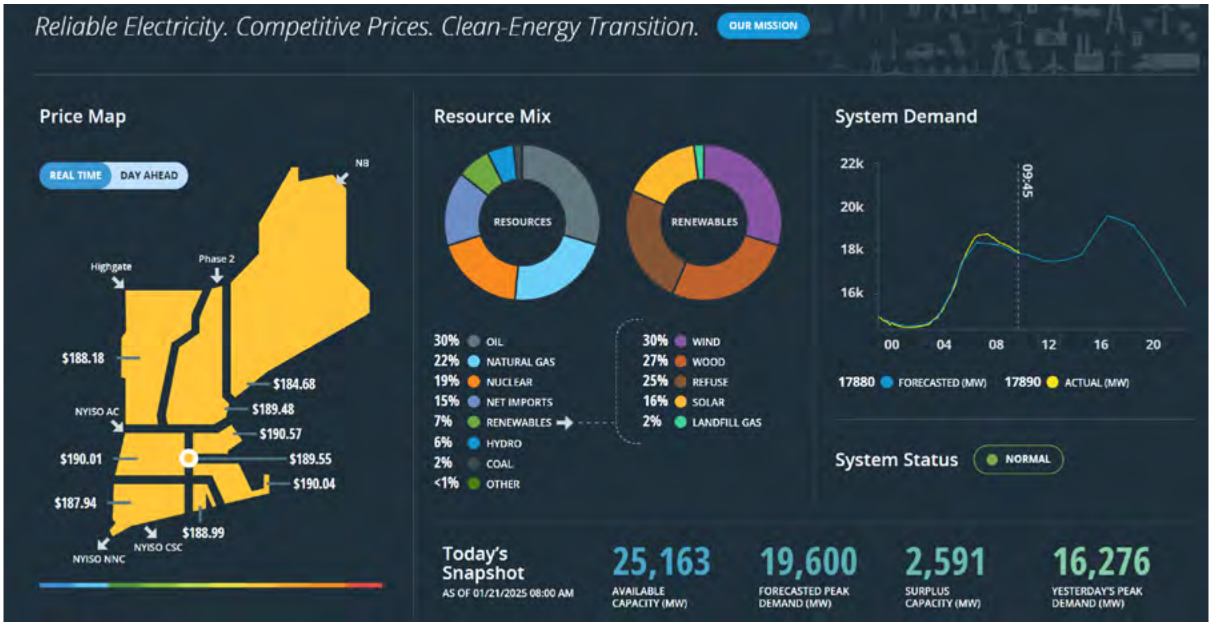
largest source of power. That wasn't part of the plan a decade ago, when wind turbines in the Atlantic were going to replace fossil fuels.

Figure 3: New England Power Supply at 0800 on January 21, 2025



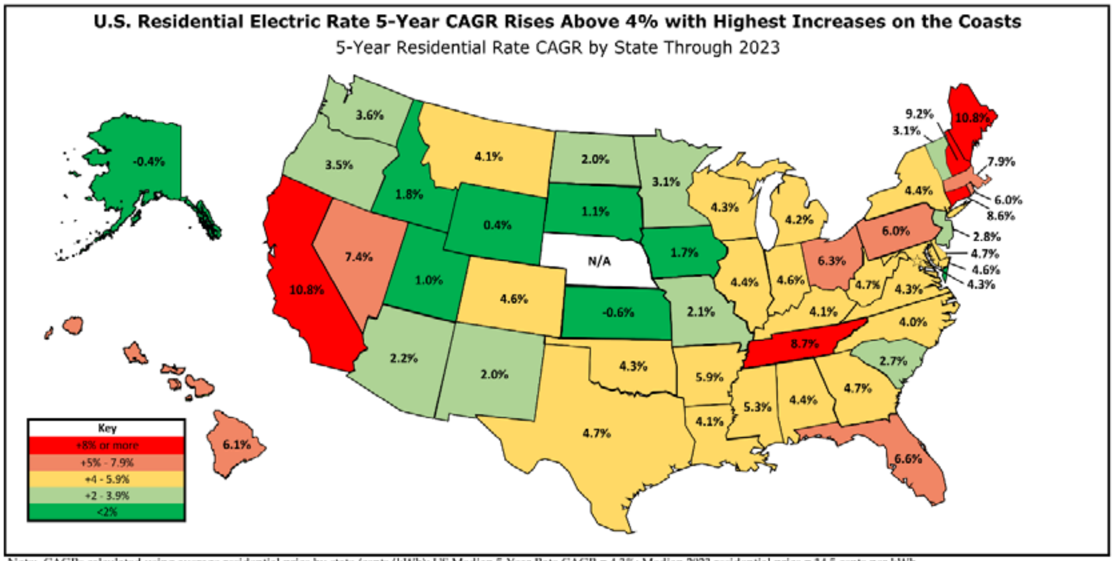
Source: ISO New England

New England's ambitious electrification plans rely heavily on a mix of offshore wind power and battery storage—about 40 gigawatts in total. Yet those continue to develop at a halting pace, challenged by high installed costs exacerbated by inflation and higher interest rates as well as uncertainty surrounding federal permitting and tax policy. Accordingly, the region's "one-basket" electrification solution appears to be lacking a few eggs (and gas pipelines). A holistic, networked approach that makes better use of natural gas to mitigate peak demand through efficiency and distributed solutions could enhance resilience and reliability for all customers, while still facilitating greater use of renewable electricity.

3 KEEPING ENERGY AFFORDABLE

On average, U.S. residential electricity bills have risen at a compound annual growth rate of 4% over the five years ending in June 2023, as shown in Figure 4, while some states have experienced substantially higher increases. In California, for example, residential usage above a couple hundred kilowatt-hours per month can be billed at tiered rates approaching $0.60/kWh. By comparison, U.S. residential rates average $0.17/kWh for usage of 900kWh per month.

Figure 4: U.S. Residential Electricity Rate Heat Map



Note: CAGRs calculated using average residential price by state (cents/kWh); US Median 5-Year Rate CAGR = 4.3%; Median 2023 residential price = 14.5 cents per kWh
Note: Nebraska does not have any Investor-Owned Utilities
Source: SNL Financial LC and Wells Fargo Securities, LLC
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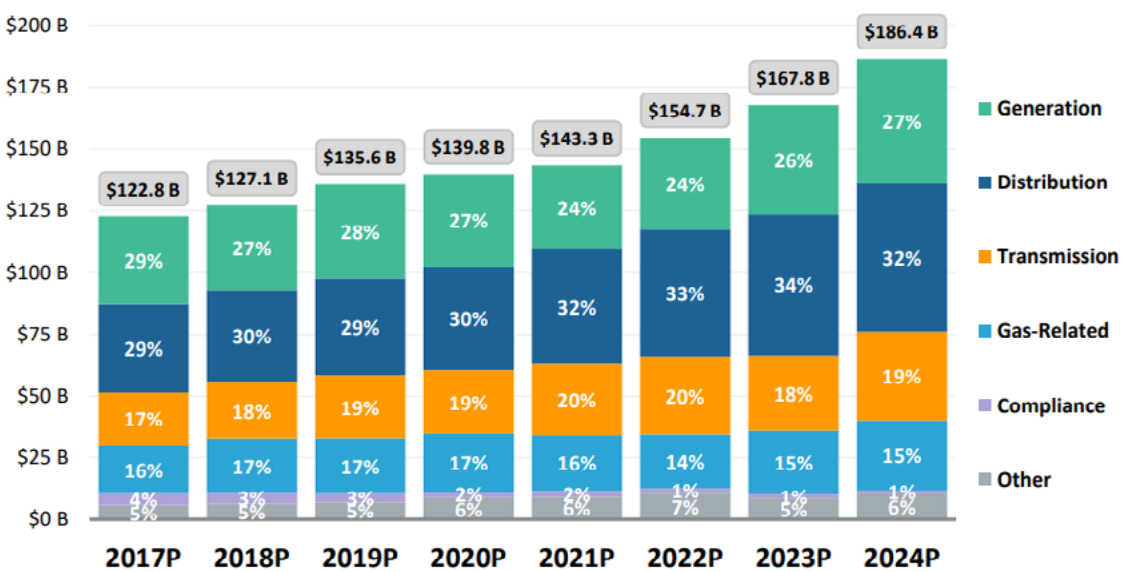
Bills are affected by many factors, however. Utility capital investment is a key driver as those expenditures ultimately make their way into rate base determination. Investments in electric transmission and distribution networks have come to dominate the industry's capital spending. As reflected in Figure 5, electric utility capital expenditures have increased at roughly a 6% 5-year compound annual growth rate, while the growth rate for transmission and distribution exceeds 7%.

Figure 5: U.S. Electric Utility Capital Investment by Function



Source: Edison Electric Institute

States with ambitious electrification plans will likely experience further upward rate pressure, especially if distribution networks need to be upgraded to accommodate increased load. As described above, these needs may become particularly acute during peak demand times that likely will accompany increased heat pump adoption. In colder climates, winter peaks may prove challenging when supplemental resistive heat is needed to maintain comfortable and safe temperatures—a costly and energy-intensive solution that increases customer bills through not only higher usage, but also the need for costly circuit upgrades to satisfy short-term peaks.

Some Canadian utilities are seeking to meet this challenge through hybrid electric and gas heating, a cooperative approach that uses natural gas when cold temperatures drive a need for supplemental heating. This allows for greater deployment of heat pump technology to achieve greater energy efficiency while also mitigating the winter peak challenge. Importantly, under this arrangement the electric utility compensates the gas utility for lost sales volume, allowing the gas system to serve as a highly cost-effective peaking resource. This “non-wires” approach leverages existing gas infrastructure to defer or avoid costly incremental investment in the electricity system—particularly for infrequent or short-duration events that can have costly economic and/or social consequences.

Electric peaking generators or compressed/liquefied natural gas storage facilities are examples of capital investments that are very useful when they’re needed, but that sit idle much of the time. Capital investment to preserve reliability for peak load events comes with a high per-unit price tag, owing to low utilization. Leveraging both gas and electric energy distribution systems could mitigate the need for further capital spending to address high-consequence, low-frequency events.

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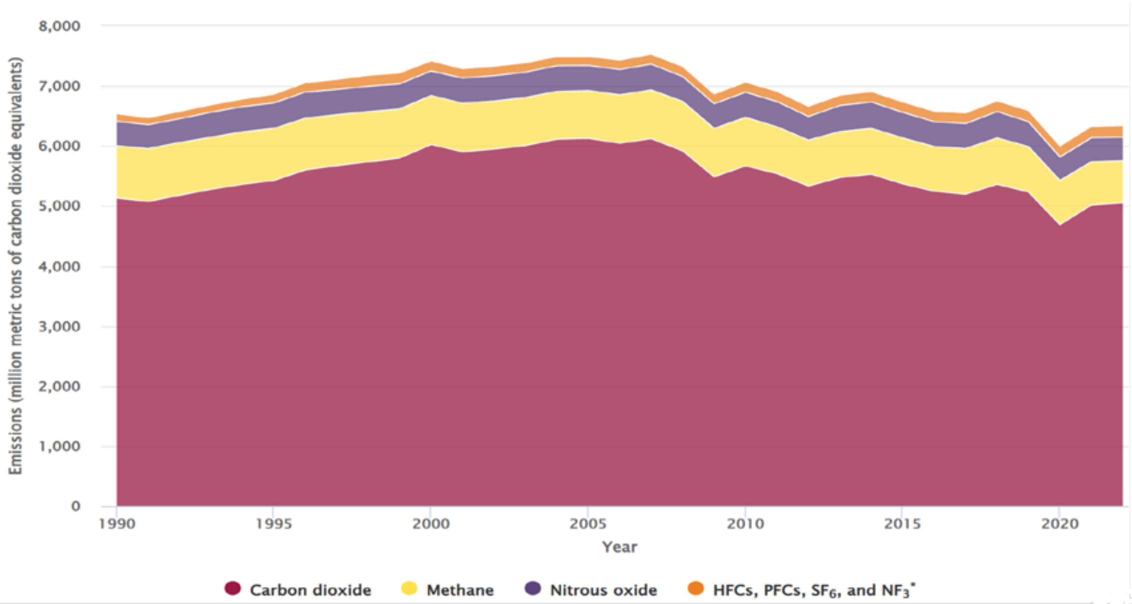
4 MINIMIZING EMISSIONS

Since peaking nearly two decades ago, United States greenhouse gas emissions have declined by over 20%, driven principally by reduced CO2 from the electricity sector as shown in Figure 6. This was largely realized through the displacement of coal as a primary energy source by a combination of wind, solar, and natural gas. While state and federal policy created incentives to incorporate greener energy resources, economics also played a role. Since 2009, the all-in cost of solar and wind energy declined 83% and 65% respectively, while natural gas emerged as a cost-effective and reliable source of dispatchable power generation that balances the inherent variability of wind and solar, thereby facilitating greater use of renewable electricity.

Figure 6: U.S. Greenhouse Gas Emissions by Type, 1990–2022



Source: U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2022 (EPA 430-R-24-004)

Electrification is often favored when emission reductions are scored on a site-specific basis. However, that approach ignores the full fuel cycle, specifically how the electricity is sourced. New England may aspire to 100% emission-free power, but that goal remains a long way off—especially on cold mornings when oil supplies most of the power (not to mention space and water heating, but that's another topic).

While displacement of coal and other carbon-heavy fuels has happened mostly at utility scale, the potential for generation in smaller, distributed increments could drive further solar and battery deployment while also helping ride through a disruption of grid power. Examples include converting liquid-fueled backup generators to gas (and dispatching them to meet high demand), increasing the use of combined heat and power systems, and deploying microgrids. Larger facilities could integrate heat pump technology with combined heat and power applications to further leverage the gas distribution network during both peak and non-peak hours.

Economic and Regulatory Challenges

Integration and coordination of electricity and gas distribution networks can meet end-user needs with better economic and logistical efficiency by using each system to its optimal potential under varying supply, demand, and weather conditions. However, this approach comes with potential challenges, including but by no means limited to:

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- Overcoming electric and gas utility companies' predisposition to defending their "turf"
- Compensating gas utilities for lost sales volume and coverage of fixed system costs
- Pricing energy resilience, reliability, and security and aligning rates with value creation and achievement of desired outcomes
- Sustaining progress and messaging on greenhouse gas emission reduction
- Allocating cost causation and rate responsibility across separately regulated systems and on both sides of the meter, especially between "pure-play" gas and electric utilities
- Sharing information, including sensitive customer data, between companies whose strategies and priorities may not align

States with zero-emission mandates may see continued use of the gas system, even in a supporting role, as counter to their electrification ideals. However, electricity currently relies heavily on natural gas in most of the U.S., a situation that's unlikely to change quickly without threatening reliability and driving up costs. Natural gas is not only the cleanest fossil fuel; it also plays a key role in deploying zero-emission resources and can continue to do so.

Meeting New Energy Challenges Together

Against a backdrop of challenges and uncertainty, how can the potential benefits of integrating electricity and gas planning be tested and proven? As is typical in utility planning, pilot programs can offer a low-cost, low-risk way to demonstrate benefits and pitfalls without a huge commitment. Examples could include:

- Electric heat pumps using natural gas for supplemental heat
- Geotargeting of gas technologies where the electric grid is overloaded or at risk
- Geotargeting of electric technologies where the gas system is overloaded or at risk
- Microgrids supported by gas and distributed energy resources serving critical infrastructure where reliability is critical

In MCR's view, the potential benefits, efficiencies, risk mitigation, and cost savings of optimizing two existing systems instead of gold-plating only one are likely to prove compelling.

Consumers demand solutions, and innovative companies find ways to provide them, often disrupting entire industries along the way. Large-scale energy consumers (i.e., data processors) are increasingly turning to non-utility providers to meet their needs. Solutions often involve a combination of renewables, energy storage, and on-site distributed generation in a microgrid configuration. To remain relevant in this dynamic business environment, electric and gas utilities need to work with customers and regulators—and with each other—to leverage and improve existing infrastructure to provide secure, reliable, affordable, and clean energy that consumers demand.

Further Reading

- Opportunities for Integrating Electric and Gas Planning, Lawrence Berkeley National Laboratory, white paper and slides, January 2025
- Hybrid Heat in Quebec: Energir and Hydro-Quebec's Collaboration on Building Heat Decarbonization, Canadian Climate Institute, April 2023
- 2024 Joint Agency Staff Paper: Progress Towards a Gas Transition, California Public Utilities Commission, February 2024
- Joint Reply Comments of Southern California Gas Company and San Diego Gas & Electric Company to Order Instituting Ratemaking, January 2025
- Final Gas System: Long Term Plan, Central Hudson Gas and Electric, November 2024
- Beyond the Buzzwords: Unpacking Energy Efficiency, Electrification and Decarbonization, American Gas Association, January 2025
- Levelized Cost of Energy 2024, Lazard, June 2024
- The Role of Natural Gas in Decarbonizing the U.S. Energy and Industrial Economy, Center for Climate and Energy Solutions, July 2021
- Investor Perspectives on Natural Gas Utilities, MCR Performance Solutions, November 2024

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