ENERGY INDUSTRY UPDATE

THE WAITING (IS THE HARDEST PART)

Volume 23 - Issue 2

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EXECUTIVE SUMMARY
The Waiting (Is the Hardest Part)

Themed "The Waiting (Is the Hardest Part)," this Fall 2023 Energy Industry Update examines recent trends in the utility and energy industry, where stakeholders are waiting for new technologies to emerge and the results of various regulatory initiatives to be seen. In this issue, we look at regulatory activity at the Federal Energy Regulatory Commission (FERC) on grid issues and at the states relating to gas sector decarbonization. We also look at the U.S. Environmental Protection Agency's (EPA) proposed power plant greenhouse gas rule and industry activity on gas-power coordination. On technology, we consider energy transition activities in Denmark and the growth in virtual power plants (VPPs) in the United States and Puerto Rico. In all of these cases, the "waiting" is indeed the hardest part for energy infrastructure development.

Some Highlights of This ScottMadden Energy Industry Update	
Waiting for the Emergence of New Technologies	▪ EPA has proposed a new rule regulating greenhouse gas emissions in fossil fuel-fired power plants. However, the proposed emissions standards use green hydrogen and high levels of carbon capture and storage as the benchmark, anticipating future technologies that are not yet at commercial scale. ▪ ScottMadden sponsored a Smart Electric Power Alliance fact-finding mission to Denmark. Denmark recently passed legislation requiring a 70% reduction in economy-wide greenhouse gas emission by 2030. Leveraging abundant wind, bioenergy, and growing solar resources, targeted investments in technologies such as power-to-fuel (e.g., green hydrogen) and carbon capture and sequestration are key elements to achieving this goal. ▪ The aggregation of distributed energy resources (DERs) into VPPs—coordinated, demand-flexible resources—is proving valuable in a growing number of markets, as hardware, software, and customer-centric energy technologies gain market traction. Evolving market rules, coupled with growing reliability concerns, will allow new VPPs to leverage a rapidly growing and technology-diverse universe of DERs.
Waiting for Results of Regulatory Proceedings	▪ Several state regulatory commissions are conducting proceedings to consider the role of natural gas distribution utilities in achieving state decarbonization goals. Gas utilities have discussed diverse strategies that provide flexibility and optionality among various technologies and maintain affordability. ▪ Coordination and interdependence of the gas and power sectors has been an issue for many years, but a thorny one to resolve. A recent industry forum yielded some progress on alignment, but more may need to be done to ensure reliability, as gas-fired power remains critical for grid reliability. FERC will consider some gas-power coordination issues this fall. ▪ FERC has cited transmission as a key area for policy development. Over the last couple of years, the bulk power system has been challenged with extreme weather (e.g., Winter Storms Uri and Elliott), cyber and physical attacks, and backlogged generator interconnection. FERC has issued several new rules to deal with some of these issues, and more actions are expected, as grid owners and operators develop compliance strategies.

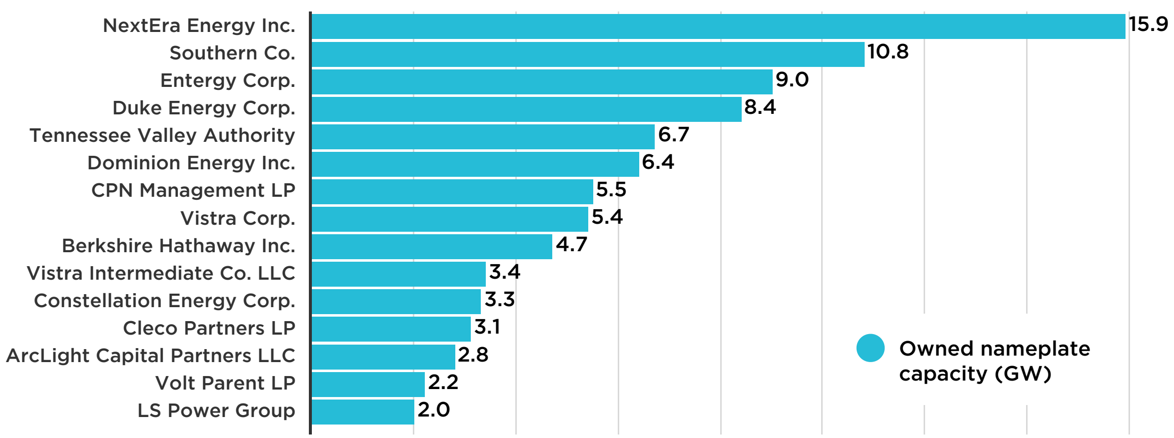
EPA's Proposed Power Plant Rule: Third Time's the Charm?

EPA proposed greenhouse gas rules for fossil fuel-fired power plants that anticipate future technologies.

EPA Proposes an Aggressive Greenhouse Gas Rule for Power Plants

- On May 11, 2023, the U.S. Environmental Protection Agency (EPA) proposed new CO_2 emissions standards for fossil fuel-fired power plants. The proposal sets limits for new and reconstructed gas-fired combustion turbines (CTs); existing coal, oil, and gas-fired steam generating units; and certain existing larger, more frequently used gas-fired CTs. Those limits are based upon emissions benchmarks set by high levels of carbon capture and storage or hydrogen-rich fuel blends.
- The proposed rule does not encompass new fossil fuel-fired steam generating resources, as it does not believe any new such units will be constructed or reconstructed. Moreover, there is some expectation that EPA will propose a rule for smaller gas-fired units not covered under this proposed rule.
- The proposed rule would repeal the 2019 Affordable Clean Energy (ACE) rule, which had been vacated and remanded by a federal court. ACE had proposed Clean Air Act (CAA) compliance for existing coal units through on-site heat rate improvement measures as well as six candidate technologies and operation and maintenance practices. EPA deemed that the ACE did not reflect the best system of emissions reduction for steam generation units. ACE had been the successor to EPA's 2014 Clean Power Plan (CPP).
- Comments were closed on the proposed rule after August 8, 2023. The timing of final promulgation is unclear, particularly as FERC will discuss the impact of the proposed rule at its annual technical conference on reliability in early November 2023.

Figure 1.1: **Top 15 Owners of Gas-Fired Generation Units* Potentially Subject to EPA Proposed GHG Rule**



Note: *Currently operating units with nameplate capacity >300 MW and annual capacity factor >50%.

Source: S&P Global Market Intelligence

KEY TAKEAWAYS

For the third time in as many presidential administrations, EPA has taken another run at CO_2 emissions rules for fossil fueled-fired power plants. The Supreme Court's 2007 decision in Massachusetts vs. EPA allows EPA to regulate greenhouse gases; the recurring question is how.

The key issue of whether standards based upon 90% carbon capture and 96% green hydrogen are "adequately demonstrated" will be hotly debated and likely litigated.

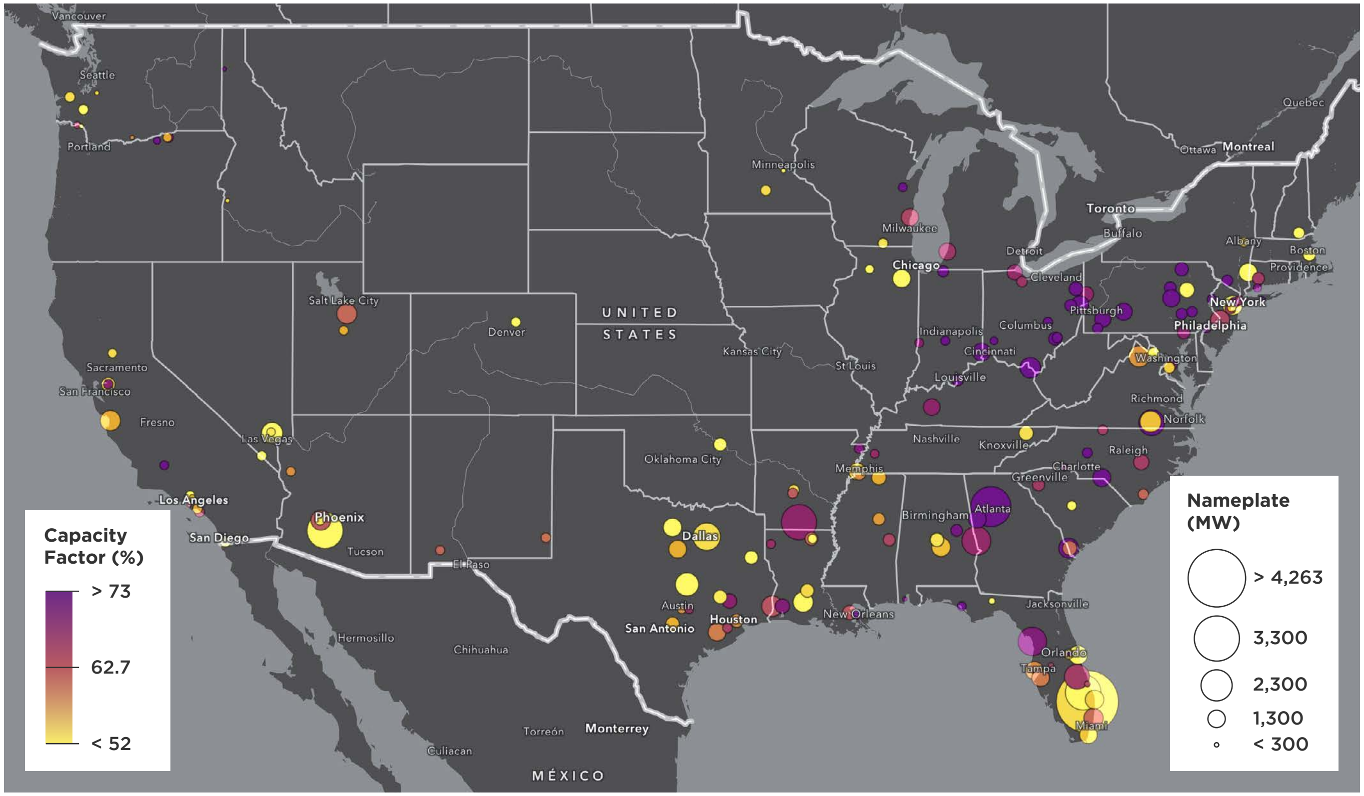
Industry participants, including FERC, will focus on additional analysis and discussion of potential reliability impacts of the proposed rule.

Incentives in the Inflation Reduction Act are expected to facilitate development and commercialization of the carbon capture and sequestration and hydrogen technologies required under the rule, but the question remains: how soon will they arrive?

Structure of the Rule: Numerous Unit Categories

- Under the CAA, new stationary emissions sources like power plants are subject to use of the "best system of emissions reduction" (BSER). The proposed rule does not use the broader approach of the CPP, which attempted to interpret BSER to include outside-the-fence approaches.
- The proposal varies targets and BSER based upon technology, duty (i.e., baseload, load-following, or peaking), and fuel. It differentiates emissions reduction limits, approaches, and compliance expectations (see Figures 1.3 to 1.5) under the following rubric:
  - Fuel type (coal or natural gas, primarily)
  - Capacity of the unit (the proposed rule has established a 300 MW threshold for comment)
  - New or existing generation
  - Remaining lifespan of unit (i.e., whether operation is planned beyond certain date thresholds)
  - Capacity factor

Figure 1.2: **Operating U.S. Gas-Fired Plants Potentially Subject to EPA's GHG Proposal***



- **EPA has estimated that 38.6 GW of gas-fired CTs are likely subject to the proposed rule.**
- **An analysis by BTU Analytics finds that the affected generation could be twice EPA estimates if steam capacity is prorated to CTs that are part of a combined-cycle plant.**

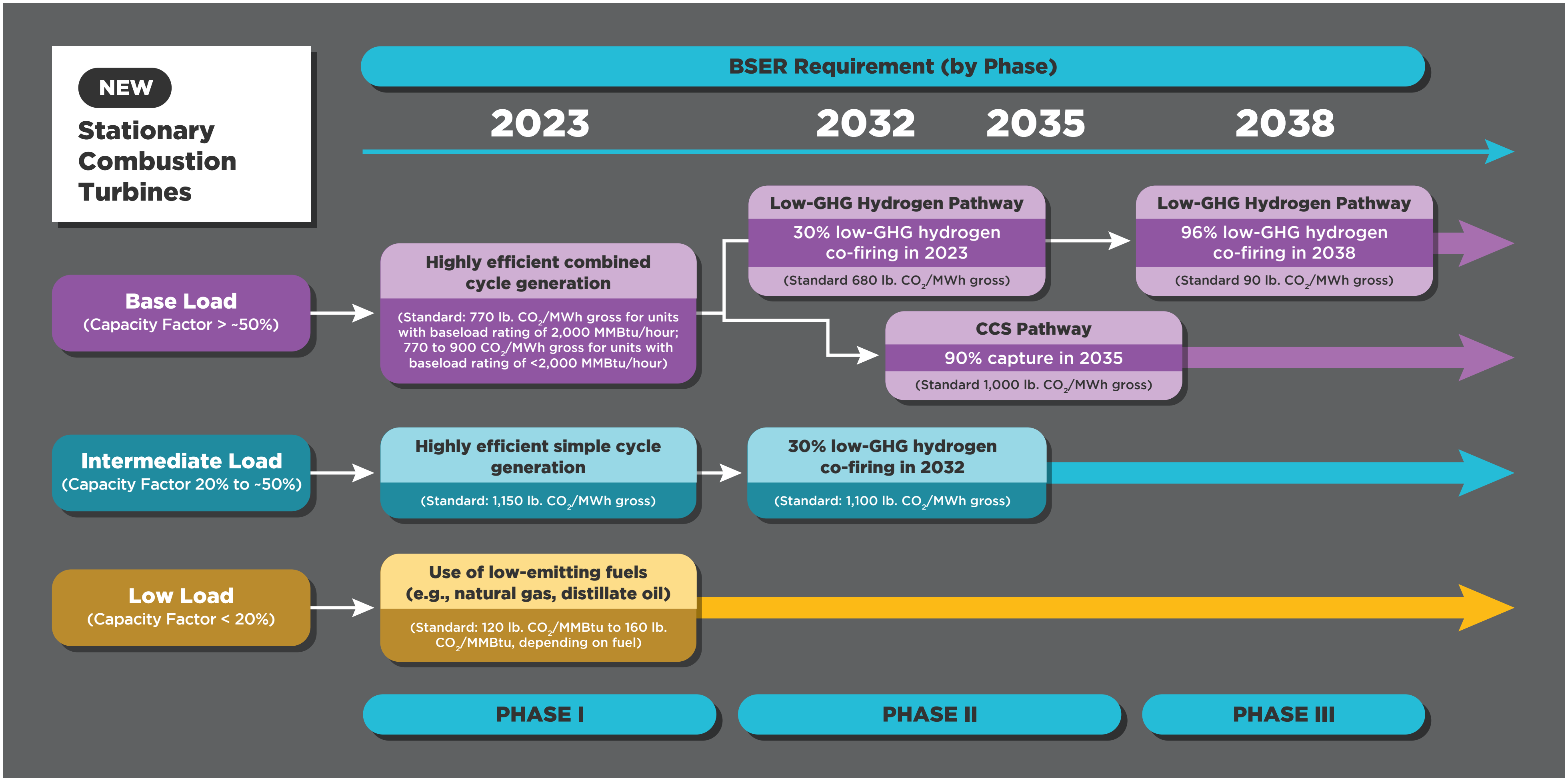
Note: *Currently operating units with nameplate capacity >300 MW and annual capacity factor >50%.

Sources: S&P Global Market Intelligence; BTU Analytics

Structure of the Rule: Numerous Unit Categories (Cont.)

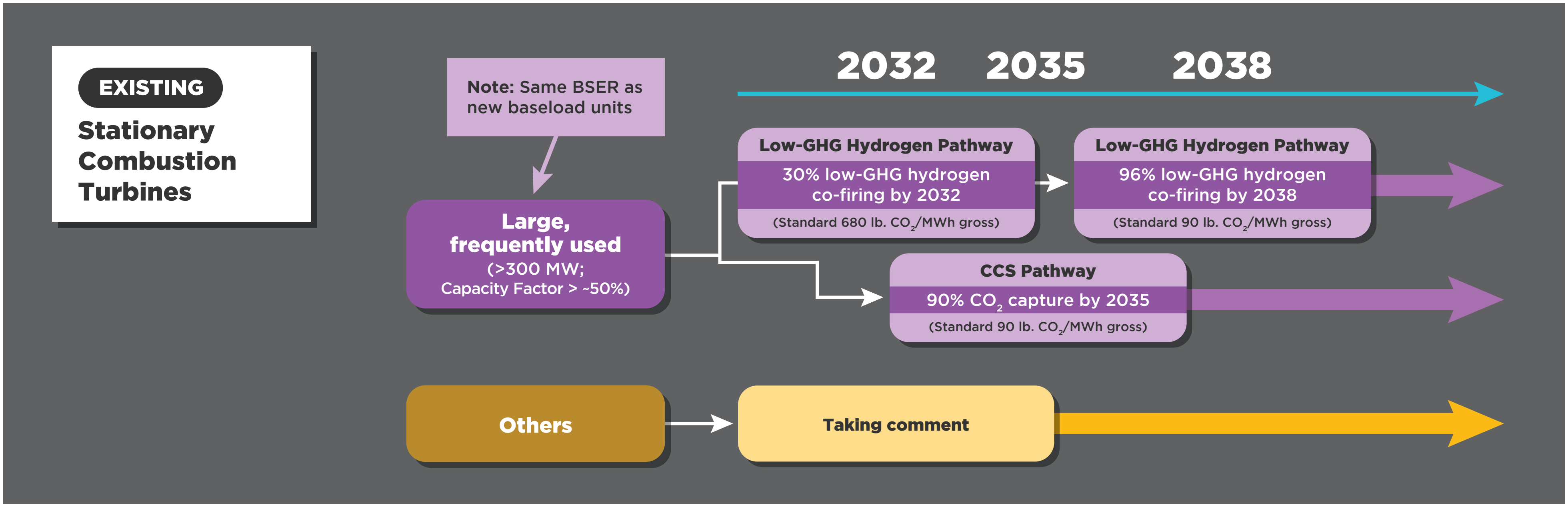
- The proposed rule puts gas-fired plants under a more rigorous compliance standard than they are currently subject to. Some other key features of the rule:
  - The proposal assumes all coal units will retire by 2040 or implement carbon capture and sequestration (CCS) at a 90% capture rate. Note that the rule requires legally enforceable commitments and milestones for affected coal units that have indicated their intent to retire to avoid retrofits under the rule.
  - Natural gas plants will have to use hydrogen blending (proportions vary by compliance year) or CCS at a high capture rate.

Figure 1.3: **Compliance Pathways: Proposal for New Stationary Combustion Turbines**



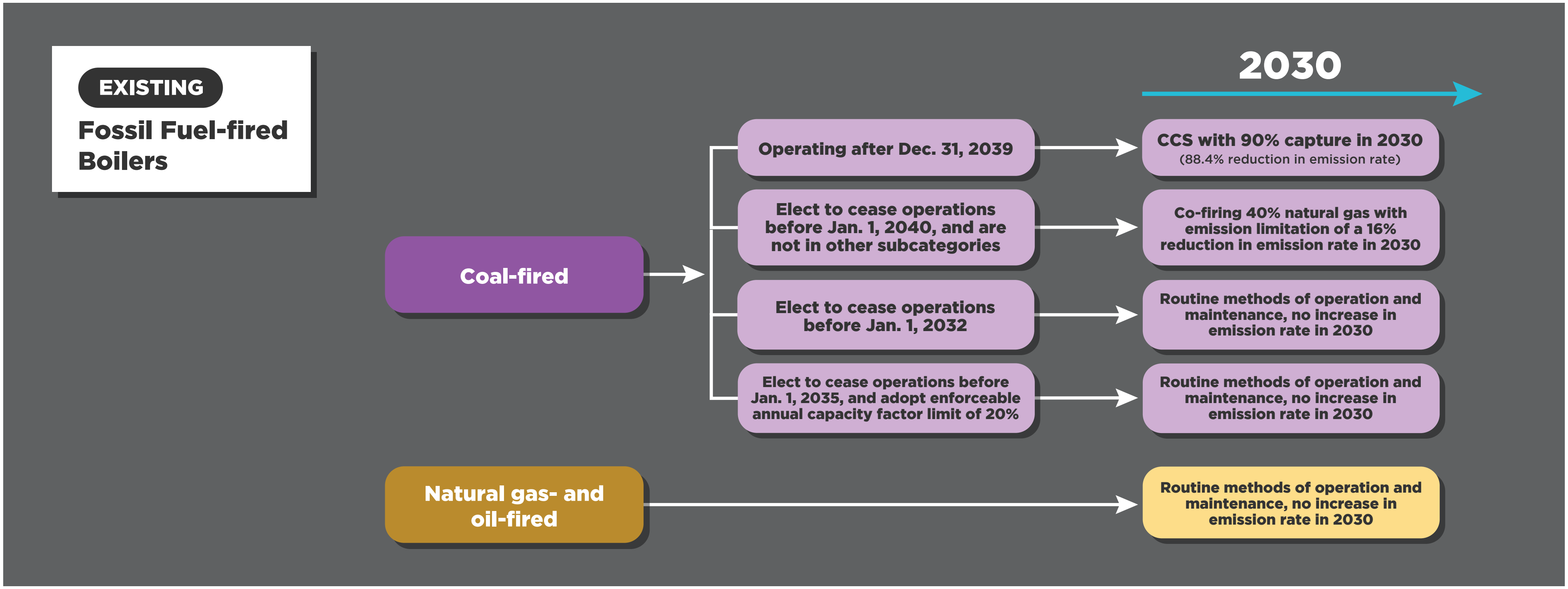
Source: EPA

Figure 1.4: **Compliance Pathways: Proposal for Existing Stationary Combustion Turbine**



Source: EPA

Figure 1.5: **Compliance Pathways: Proposal for Existing Coal-, Gas-, and Oil-Fired Boilers**



Source: EPA

EPA Estimates Effects of Proposed Rule

- EPA modeled the impact of the rule in its regulatory impact analysis (RIA) (see Figure 1.6). To characterize the effect of the rule, it set as baseline a post-Inflation Reduction Act (IRA) analysis, which modeled a significant reduction in emitting resources and increase in renewable resources. The baseline accounts for a significant amount of change in the forecast; thus, the assumed impact of the proposed rule is an incremental 23 million metric tons over the IRA baseline in 2040.
- A graphical illustration of the changes in installed capacity and generation by fuel type is shown at Figures 1.7, 1.8, and 1.9.
- A few criticisms of the RIA from some industry participants include the following:
  - **Assumes "overnight" transmission:** The analysis assumes that required transmission to deliver significantly higher renewable energy to demand centers becomes operational as needed.
  - **Natural gas prices at odds with EIA forecast:** The RIA assumes a long-term Henry Hub price of natural gas of $1.90 to $2.00* per MMBtu in 2035-2040 versus EIA projections of gas prices of $3.68 to $3.94 during the same period.
  - **Too bullish cost of hydrogen:** Clean hydrogen, which consumption under the RIA reaches nearly 300 trillion Btu (with 11 GW of natural gas units co-firing with hydrogen by 2035), is assumed to reach a price of $1/kg by 2035 (equivalent of ~$7.40/MMBtu) and $0.50/kg by 2040, compared with a current cost of $5/kg to $7.50/kg. Both hydrogen and natural gas costs are critical assumptions, as the RIA projects no effects on retail electricity prices from the baseline (estimated at ~9.3¢/kWh* in 2040). The rule also assumes adequate hydrogen delivery infrastructure by the relevant implementation dates, an ambitious target.
  - **Understatement of electrification effects:** The RIA shows that under the proposed rule, power generation would increase from 4,341 TWh in 2028 to 5,050 TWh in 2040, a 1.3% growth rate (compare 3,945 BkWh total end use in 2021). It is unclear whether assumed widespread vehicle and building electrification is factored into the analysis and costs.

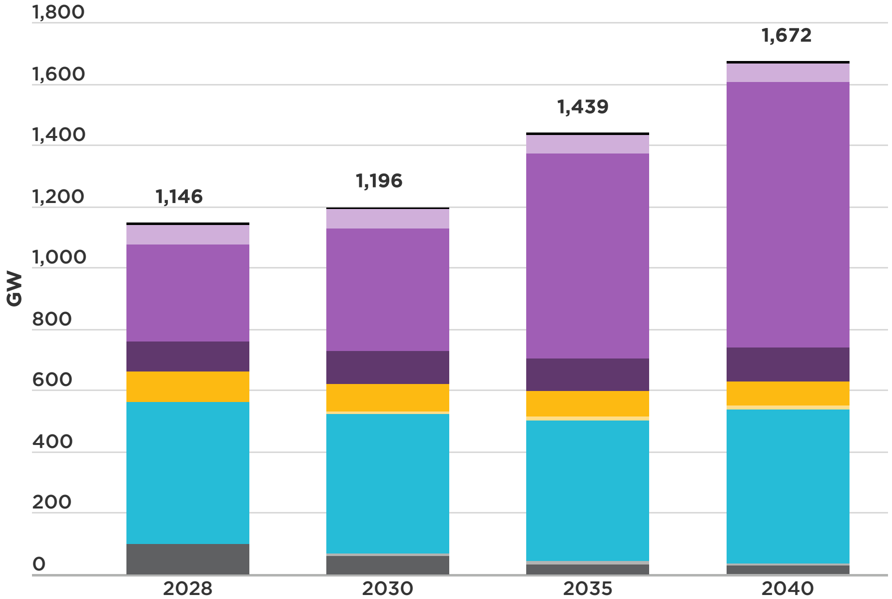
Figure 1.6: **Key Impacts of EPA Proposed GHG Rule**

Key Impacts of EPA Proposed GHG Rule per EPA Analysis

- Overall shift from coal to gas and renewables
- Projected impacts are highest in 2030, reflecting the imposition of the proposed emissions guidelines, and are smaller thereafter
- Analysis assumes 45(q) (tax credits for CCS) is available for 12 years, after which units must dispatch based on unsubsidized operating costs, reducing CCS utilization
- 45 GW of coal-fired units have committed retirements by 2035 and operate at an annual capacity factor of 20% or less in 2030; only 9 GW of coal-fired units (all with CCS) remain by 2040
- Total coal retirements between 2023 and 2035 are projected to be 126 GW (or 18 GW annually), compared to a recent historical retirement rate of 11 GW per year from 2015 to 2020
- 25 GW of economic gas combined-cycle additions occur by 2035 (300 MW incremental to the IRA baseline), and 43 GW of economic gas CT additions occur by 2035 (23 GW incremental to the IRA baseline)
- Thermal resources tend to be operated less frequently over time

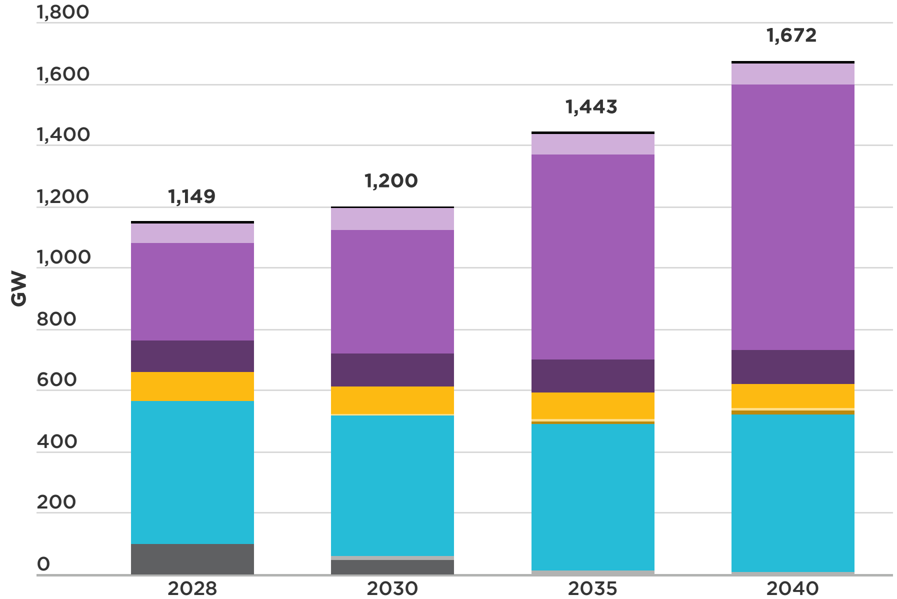
Source: EPA

Figure 1.7: **Projected Capacity by Fuel Type Under Baseline EPA Analysis (IRA) (2028-2040) (GW)**



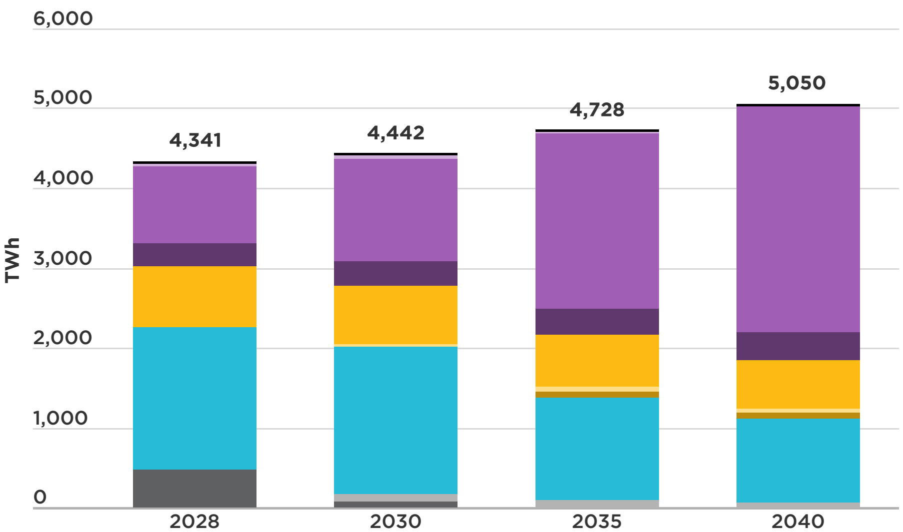
Source: EPA

Figure 1.8: **Projected Capacity by Fuel Type Under Proposed EPA Greenhouse Gas Rule (2028-2040) (GW)**



Source: EPA

Figure 1.9: **Projected Generation by Fuel Type Under Proposed EPA Greenhouse Gas Rule (2028-2040) (TWh)**



Source: EPA

Legend:

- Other
- Oil/Gas Steam
- Non-Hydro Renewables
- Hydro
- Nuclear
- Natural Gas with CCS
- Natural Gas with H2 Co-firing
- Natural Gas
- Coal with Nat Gas Co-firing
- Coal with CCS
- Coal

EPA assumes that its proposed GHG rule will have only modest incremental impacts on the capacity mix, attributing much of the anticipated changes in that mix to effects of the Inflation Reduction Act.

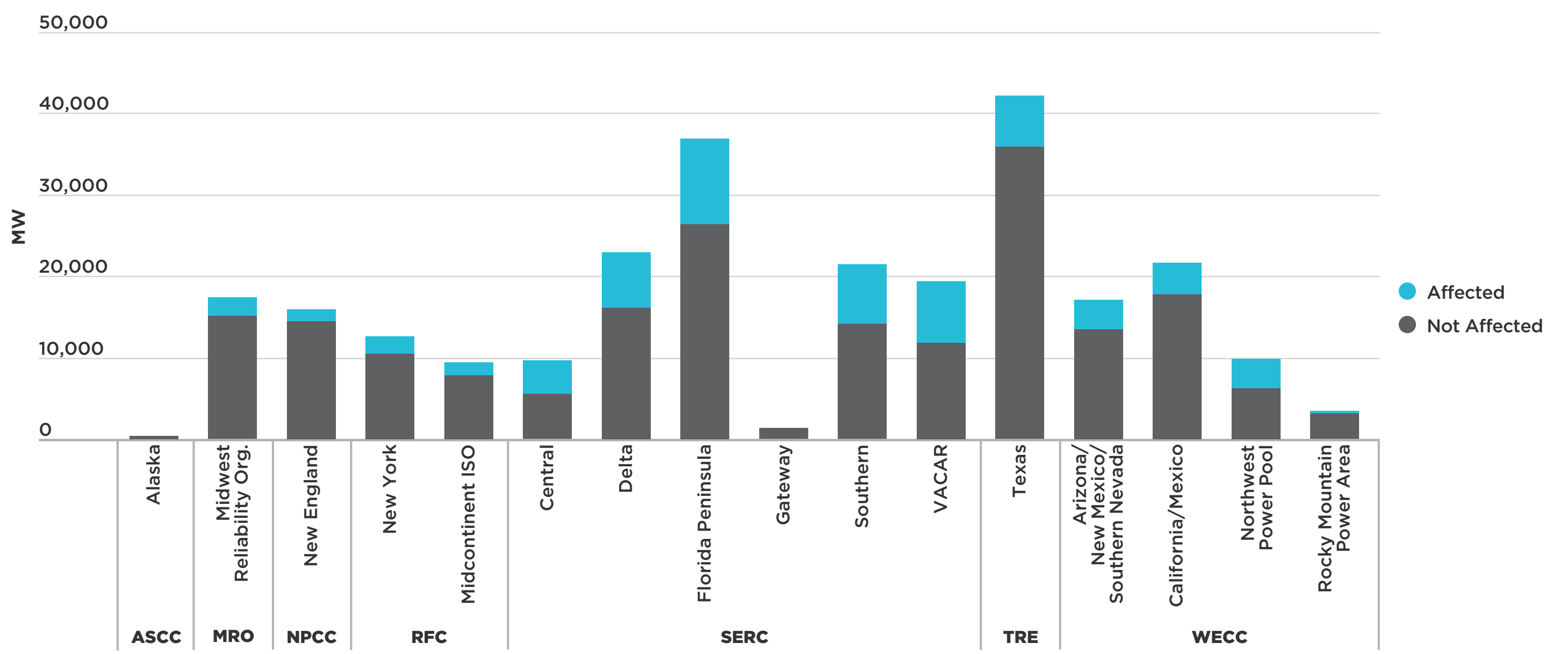
"Adequately Demonstrated" or a Big Bet on New Technology?

- A key requirement under the Clean Air Act §111, EPA must determine the BSER that is "**adequately demonstrated**", taking into account the cost of the reductions, non-air quality health and environmental impacts, and energy requirements to determine the emissions limitations under its regulations (emphasis added). The EPA spends much time in the proposal discussing adequate demonstration from a legal perspective.
- EPA argues in the proposal that it may treat a set of control measures as "adequately demonstrated" **regardless of whether the measures are new or in widespread commercial use** and **may reasonably project the development of a control system at a future time and establish requirements that take effect at that time** (emphasis added). EPA states that CCS with 90% CO_2 capture and clean hydrogen co-firing meet the criteria for adequate demonstration.
  - In its 2015 greenhouse gas (GHG) new source performance standards, EPA found that CCS was adequately demonstrated (including being technically feasible) and widely available and could be implemented at reasonable cost.
  - EPA also found that low-GHG hydrogen co-firing is a BSER for the target compliance date given developments in turbine technology that can accommodate increasing blends of hydrogen.
- Critics point out that both CCS and clean hydrogen fuel require significant new pipeline infrastructure to sequester CO_2 or move hydrogen, respectively, and the difficulty of siting such facilities. They also point to the lack of scale of either technology and uncertain time and cost of those technologies.
- The Biden administration points to generous tax credits under the IRA that will be drivers of these technologies: \$85/ton of CO_2 captured and stored; \$3/kg for hydrogen with a CO_2-emitted equivalent of <0.45 kg of CO_2-equivalent per kg of hydrogen.
- EPA's interpretation of "adequately demonstrated" will likely be a subject of litigation over the rule, if promulgated as proposed.

Many Open Questions and Issues

- The proposed rule solicited comments and input on many issues surrounding implementation and left open others for consideration. Those include the following:
  - **Thresholds:** Characterization of "large" (300 MW) and baseload (>50% capacity factor) may be adjusted based upon comments.
  - **RULOF:** EPA notes that states could apply less stringent standards based upon a particular facility's remaining useful life and other factors (RULOF), although it is uncertain what kind of showing is required to demonstrate that the facility cannot reasonably achieve the stringency of the BSER.
  - **Operating disincentives:** ISO-New England pointed out in it comments that the capacity factor thresholds will incentivize less efficient operations of the natural gas fleet and will also reduce production by gas units nearing the 50% threshold that may be needed for system reliability. Its simulations found that fossil generation would not decrease, but it would shift from larger, efficient gas turbines to smaller, less efficient oil- and gas-fired units.
- System operators had significant concerns about the effect of the rule, fearing that if the technology and infrastructure failed to timely materialize, then forced retirements of coal and even efficient gas-fired generation would leave the future supply of dispatchable generation below what is needed to serve demand, potentially resulting in "material, adverse impacts" to reliability.
- The proposal may be favorably received by utilities that have been pursuing net-zero goals and IRA-assisted projects, such as NextEra, which includes in its blueprint converting 16 GW of gas units to run on green hydrogen.
- Other comments by various stakeholders are summarized in Figure 1.11.

Figure 1.10: **Capacity (MW) of Gas-Fired Combustion Turbines Potentially Affected by Proposed GHG Rule by Reliability Region and Subregion**



Source: S&P Capital IQ Pro; ScottMadden analysis

Figure 1.11: **Selected Filed Comments on EPA's Proposed Power Plant GHG Rule**

	Comments	Commenter
Environmental Organization	▪ **Any variances from rule on individual unit basis:** EPA must strengthen remaining useful life and other factors (RULOF) framework to guide states and limit inappropriate applications. EPA should not allow states to use aggregate demonstrations to establish RULOF variances... but fundamental differences of an individual plant must be shown to make BSER unreasonable. ▪ **Hydrogen an issue:** Hydrogen infrastructure buildout entails significant climate and environmental justice risks.	**Environmental Defense Fund**
Electric Industry Organization	▪ **Capacity factor:** In finalizing low-utilization units, EPA should finalize a higher capacity factor to account for reliability considerations. ▪ **Flexibility:** EPA's proposed approach to existing natural gas-based turbines is not supported by sufficient analysis; additional and comparable (to coal plant rules) flexibility is needed.	**Edison Electric Institute**
Technology and Equipment Industry Organization	▪ **Policy alignment on "clean" hydrogen:** EPA should replace mandate that CTs only combust EPA-defined low-GHG hydrogen with definition of clean hydrogen per Dept. of Energy and Dept. of the Treasury (i.e., <4 kg CO_2-equivalent per kg hydrogen vs. EPA's 0.45). ▪ **NET Power Cycle:** EPA should recognize the NET Power Cycle (utilizes super-critical CO_2 as the turbine's working fluid in a gas-fired plant) as an alternative compliance pathway.	**Baker Hughes**
	▪ **Peaking unit definition:** While supporting the clean fuel standard for the peaking gas turbine category, the peaking category should be increased to at least 25% to provide "unconstrained grid flexibility" to meet future grid demand.	**Mitsubishi Power Americas**
System Operators	▪ **BSER not proven:** The proposed rule's BSER determination overstates the commercial viability of CCS and hydrogen co-firing today and ignores the cost and practicalities of developing new supporting infrastructure within the time frames projected. ▪ **Chilling effect on investment:** The proposed rule could have a chilling effect in the near term on the investment needed to maintain dispatchable generating units until these new technologies develop. With continued and potentially accelerated retirements of dispatchable generation, supply of these reliability attributes will dwindle to concerning levels. ▪ **Reliability-driven rule modifications:** If rule is adopted, it should include a new sub-category of unit needed for local or region-wide reliability and have a mechanism to monitor and adjust compliance schedule based upon development of CCS and hydrogen infrastructure.	**Joint Comments of ERCOT, MISO, PJM, and SPP**

Note: Some comments have been summarized and paraphrased for brevity.

Source: Comments of parties noted, available at www.regulations.gov/docket/EPA-HQ-OAR-2023-0072

IMPLICATIONS

The Biden administration continues its "all of government" carbon emissions reduction efforts, of which EPA's proposed power plant GHG rule is a part. It is unclear how many of the terms of the proposed rule will be promulgated, and another rulemaking for smaller units can be expected.

Utilities with net-zero mandates or aspirations are likely considering emissions reduction strategies, including (but not limited to) the BSER proposed by EPA. But both utilities and system operators will need to analyze risks (particularly around reliability), bridging and compliance strategies, and unit-specific implications of the proposed rule. Regardless of outcome of the proposal, the pressure on the thermal generation sector will continue.

Notes:

*2019$

Sources:

EPA Fact Sheet, "Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule" (May 2023); EPA Webinar, *Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, Webinar for Communities with Environmental Justice Concerns and Members of Tribal Nations* (June 6, 2023); Proposed Rule, *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units*, 88 Fed. Reg. 33240 (May 23, 2023) (to be codified 40 C.F.R. pt. 60); Comments of ISO New England Inc., EPA-HQ-OAR-2023-0072 (Aug. 7, 2023); Congressional Research Service, Clean Air Act: Electricity Sector and Greenhouse Gas Standards (Mar. 12, 2021); EPA Presentation, "Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions from Fossil Fuel-Fired Electric Generating Units" (May 2023); FERC Notice of 2023 Annual Reliability Technical Conference, Docket No. AD23-9-000 (Aug. 3, 2023); Congressional Research Service, Greenhouse Gas Emission in the U.S. Electricity Sector: Background, Policies, and Projections (May 18, 2023); Van Ness Feldman, "EPA Releases Landmark Greenhouse Gas Standards for Power Plants" (May 12, 2023); EPA, Regulatory Impact Analysis for the Proposed New Source Performance Standards for Greenhouse Gas Emissions (May 23, 2023); U.S. Chamber of Commerce Global Energy Institute, A Closer Look at EPA's Powerplant Rule (June 2023); U.S. Department of Energy Hydrogen Program, U.S. National Clean Hydrogen Strategy and Roadmap (June 2023); "US EPA Proposes Carbon Capture, Hydrogen Rules for New and Existing Power Plants," S&P Capital IQ Pro (May 11, 2023); "Grid Operators Warn US EPA Proposal Could Lead to 'Significant Power Shortages'," S&P Capital IQ Pro (Aug. 9, 2023); "EPA Emissions Rule Puts Subset of Gas Plants on Notice; NextEra Tops Owners List," S&P Capital IQ Pro (July 21, 2023)

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CO2

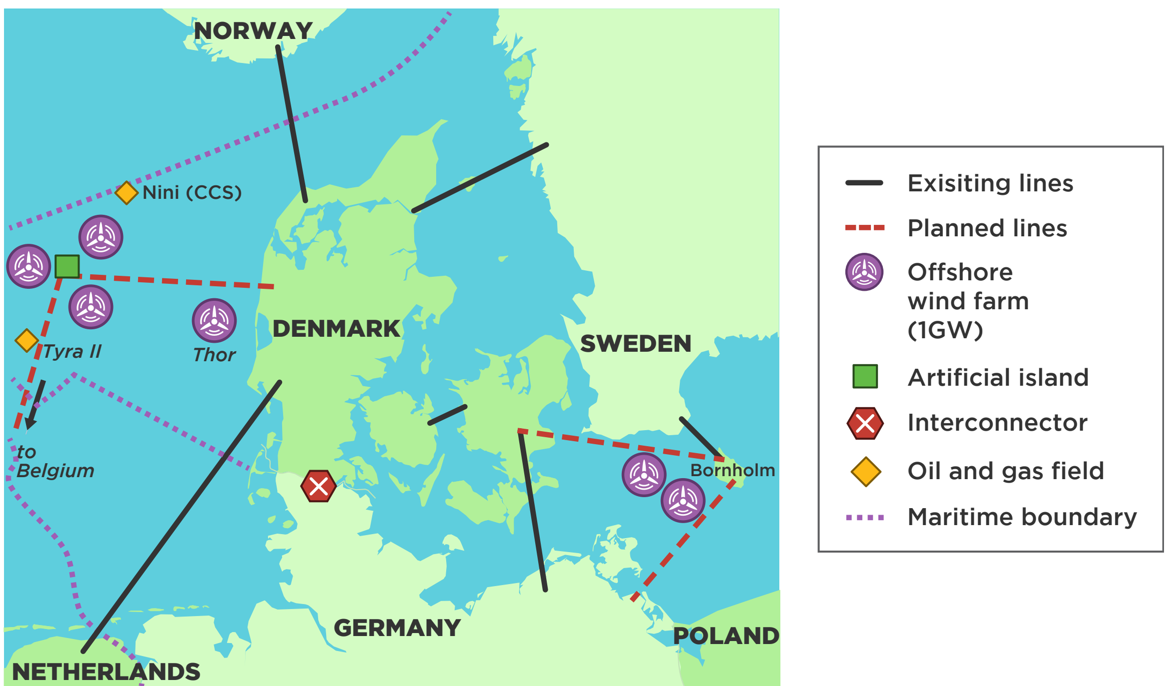
Denmark's Clean Energy Transition

A small country with big ambitions to be a regional leader in low-carbon emissions energy.

Fact-Finding Mission Finds Strong Focus on Green Fuels and Carbon Capture

- In June 2023, ScottMadden sponsored the Smart Electric Power Alliance's fact-finding mission to Denmark to better understand the country's ongoing clean energy transition.
- Denmark and neighboring countries in the North Sea envision the growth of cheap renewables, production of green hydrogen, and ability to store carbon will drive economic development in the region.
- As a small country jutting into the North Sea, Denmark plans to use its unique location, industry experience, and diverse resources to become a regional leader with a particular focus on clean fuels and carbon capture and sequestration (CCS).
- Utility executives from the United States found stakeholders in Denmark working together to implement enabling policies, encourage technology innovation, and launch market rules to ensure the energy transition becomes a major economic engine.

Figure 2.1: **Denmark's Energy Infrastructure and Offshore Electricity Generation**



Source: Danish Energy Agency, S&P Global Commodity Insights

KEY TAKEAWAYS

Denmark is pursuing an aggressive clean energy transition, initially targeting a 70% reduction in economy-wide greenhouse gas reductions by 2030 and ultimately reaching net-neutrality by 2050 or sooner.

With an eye toward long-term economic growth, Denmark is beginning to invest heavily in the development and expansion of renewables, Power-to-X, and CCS technologies, companies, and infrastructure.

If successful, Denmark will support the regional energy transition by offering neighboring countries relatively cheap, clean fuels and carbon storage and accelerate the global energy transition by exporting specialized technologies and services.

Climate Legislation and Global Offshore Wind Leadership Provide Blueprint

- The Danish Parliament passed the Climate Act in 2020, which requires a 70% reduction in economy-wide greenhouse gas (GHG) emissions in 2030 (relative to 1990 levels) and climate neutrality by 2050. A new federal government formed in December 2022 moved the climate-neutrality target forward to 2045.

- To achieve the original objectives outlined in the Climate Act, Denmark plans to:

  - Increase wind and solar capacity by a factor of 2.5 from 2020 to 2030

  - Decrease thermal power plant capacity by about 40%, from 7 GW in 2020 to approximately 4 GW in 2030

  These changes are expected to result in renewable energy supplying about 97% of Denmark's electricity consumption by 2030, even as that consumption is expected to increase by 57% from 2019 to 2030.

- Even more notably, the law closely aligns with Denmark's ambition to provide a leadership role in the global energy transition.

  - Denmark's previous success includes pioneering—and eventually exporting—offshore wind technologies and services.

  - Pursuing a rapid energy transition may provide opportunities to export new technologies and services.

  - Denmark's Integrated National Energy and Climate Plan put it simply: "Denmark must be known as a nation of green entrepreneurialism."

- Even with a clear vision, cost remains an important consideration.

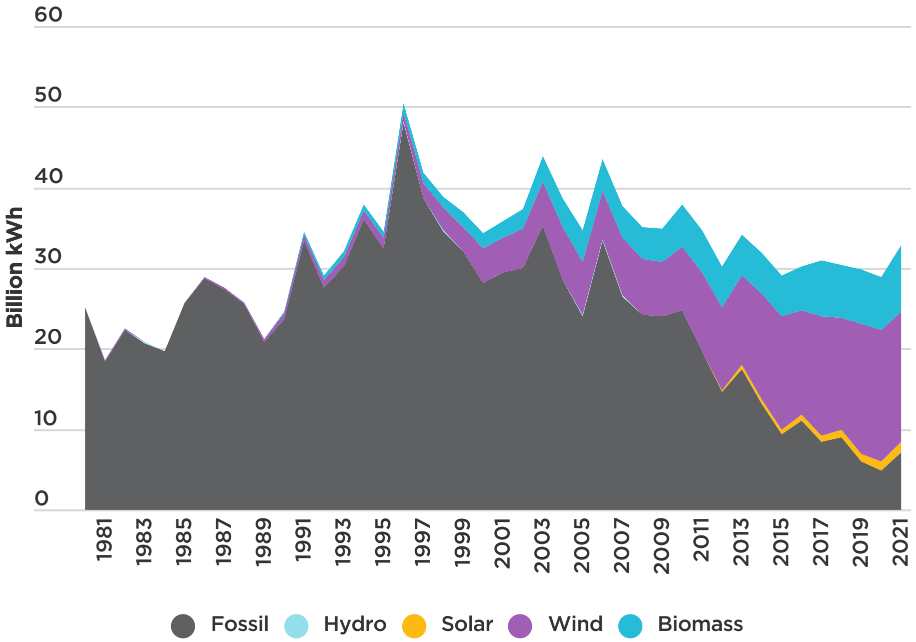
  - In June 2020, Denmark announced they would construct two "energy islands" to serve as hubs that gather electricity from surrounding offshore wind farms.

  - The construction of energy islands allows wind turbines to be placed further away from the coast and distribute the power they generate across several countries more efficiently.

  - The plan envisages an artificial island in the North Sea that will serve as a hub for 3 GW of offshore wind, with a long-term expansion potential of 10 GW. A second energy island in the Baltic Sea will serve as a hub for 3 GW of offshore wind.

  - In June 2023, the government postponed opening bids for the North Sea energy island after the Danish Energy Agency estimated costs would exceed 50 billion DKK (~$7B USD).

Figure 2.2: **Danish Electricity Generation by Fuel Type (Billion kWh)**



Source: U.S. Energy Information Administration

Power-to-X Represents Multiple Products and Market Opportunities

- In Denmark, the term Power-to-X (or PtX) refers to technologies that produce fuels, chemicals, and materials based on green hydrogen.
  - More specifically, the term describes the process of converting electricity and water into hydrogen through electrolysis driven by renewable resources.
  - This "green hydrogen" may subsequently be used directly as a fuel (e.g., road transport, industrial purposes) or converted into other fuels, chemicals, or materials.
- In a strategy published in December 2021, Denmark outlined how PtX will play a significant role in the green transformation of the transport and industry sectors, where electrification may be too expensive or impractical (see Figure 2.3).

Figure 2.3: **Denmark's PtX Development Strategy**

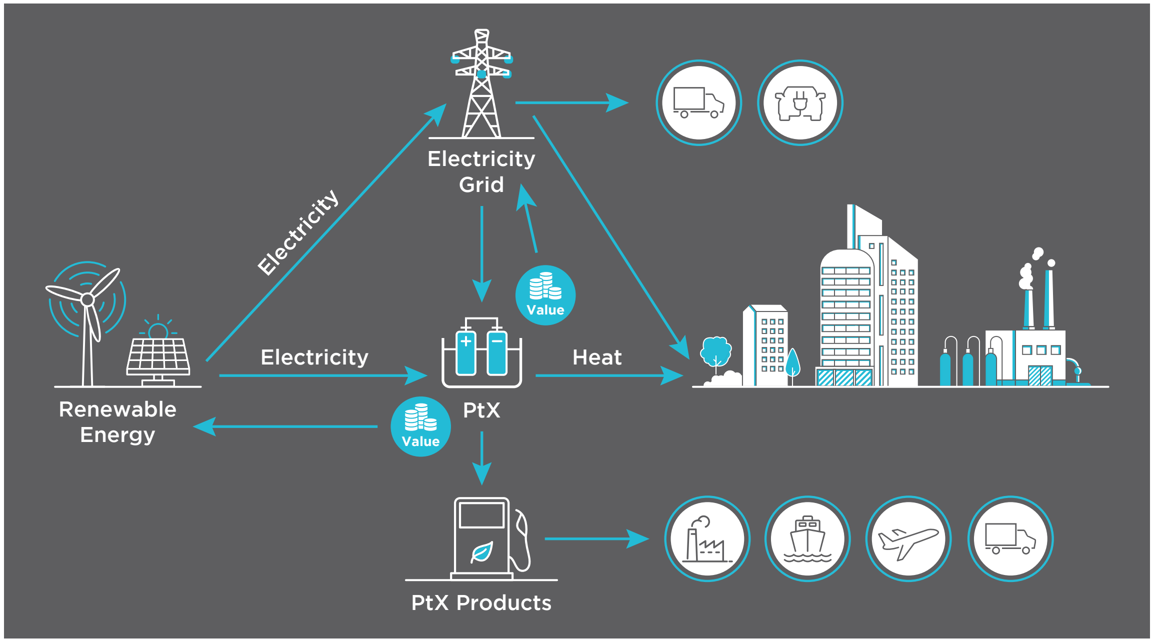
Objective	Observations
PtX must be able to contribute to the realization of the objectives in the Danish Climate Act.	▪ The Danish Energy Agency notes PtX applications should focus on sectors, such as shipping and aviation, where direct electrification is not possible or prohibitively high cost (Figures 2.4 and 2.5). ▪ PtX may also play a significant role in other sectors, but there is more uncertainty related to to competition with electrification and other technologies.
The regulatory framework and infrastructure must be in place for Denmark to utilize its strengths and allow PtX to perform on market terms in the long run.	▪ The Danish Energy Agency forecasts PtX will eventually compete on market terms with other fossil fuel alternatives. However, achieving this outcome will require establishing a supportive regulatory environment and infrastructure for PtX production, transport, storage, and utilization. ▪ Notable key measure would include legislation establishing a clear framework and green value of PtX and hydrogen infrastructure linking production to consumption and facilitates storage.
The integration between PtX and the Danish energy system must be improved.	▪ PtX can work alongside heating and gas systems, but its integration with the electricity system is particularly important. ▪ Electrolysis plants can play a key role by ramping up or down, depending on current renewable electricity output. ▪ In addition, electrolysis plants that are flexible and appropriately located can help reduce or postpone the need for reinforcement and investments in the electricity grid.
Denmark must be able to export PtX products and technologies.	▪ Exporting PtX products and technologies made in Denmark can help neighboring countries achieve European Union and Paris Agreement emission-reduction targets. ▪ This would create enhanced commercial opportunities for Danish businesses, resulting in domestic growth and jobs.

Source: Danish Energy Agency

Power-to-X Represents Multiple Products and Market Opportunities (Cont.)

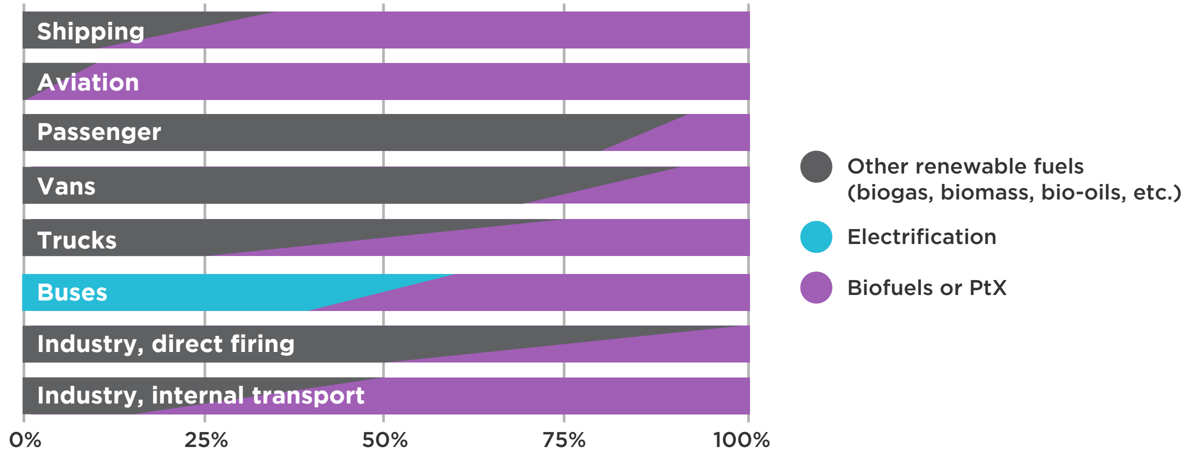
- Denmark is encouraging PtX development with the following recent activities:
  - In March 2022, the Danish government announced a "PtX Agreement" detailing the following measures:
    - Target 4 to 6 GW of electrolysis capacity by 2030
    - Dedicate 125 billion DKK (~$18B USD) to support production of PtX in Denmark
    - Enable direct lines, geographically differentiated tariffs, and local collective tariff structures
    - Enable the build-out of infrastructure for hydrogen in Denmark
    - Appoint a PtX taskforce to support development of a market and infrastructure for hydrogen in Denmark
  - In April 2023, the Danish Energy Agency opened bids for the 1.25 billion DKK (~$180M USD) in federal support.
    - Interested companies had until September 1, 2023, to submit bids.
    - Winning bidders must reach full capacity and start green hydrogen production within four years of signing contract.
  - In July 2023, an executive order made it possible to issue a "guarantee of origin" for hydrogen, thereby allowing PtX players to trade and use green hydrogen.

Figure 2.4: **Overview of Power-to-X (PtX) Ecosystem**



Source: Danish Energy Agency

Figure 2.5: **Power-to-X (PtX) Transition Potential as % of Industry Energy Consumption**

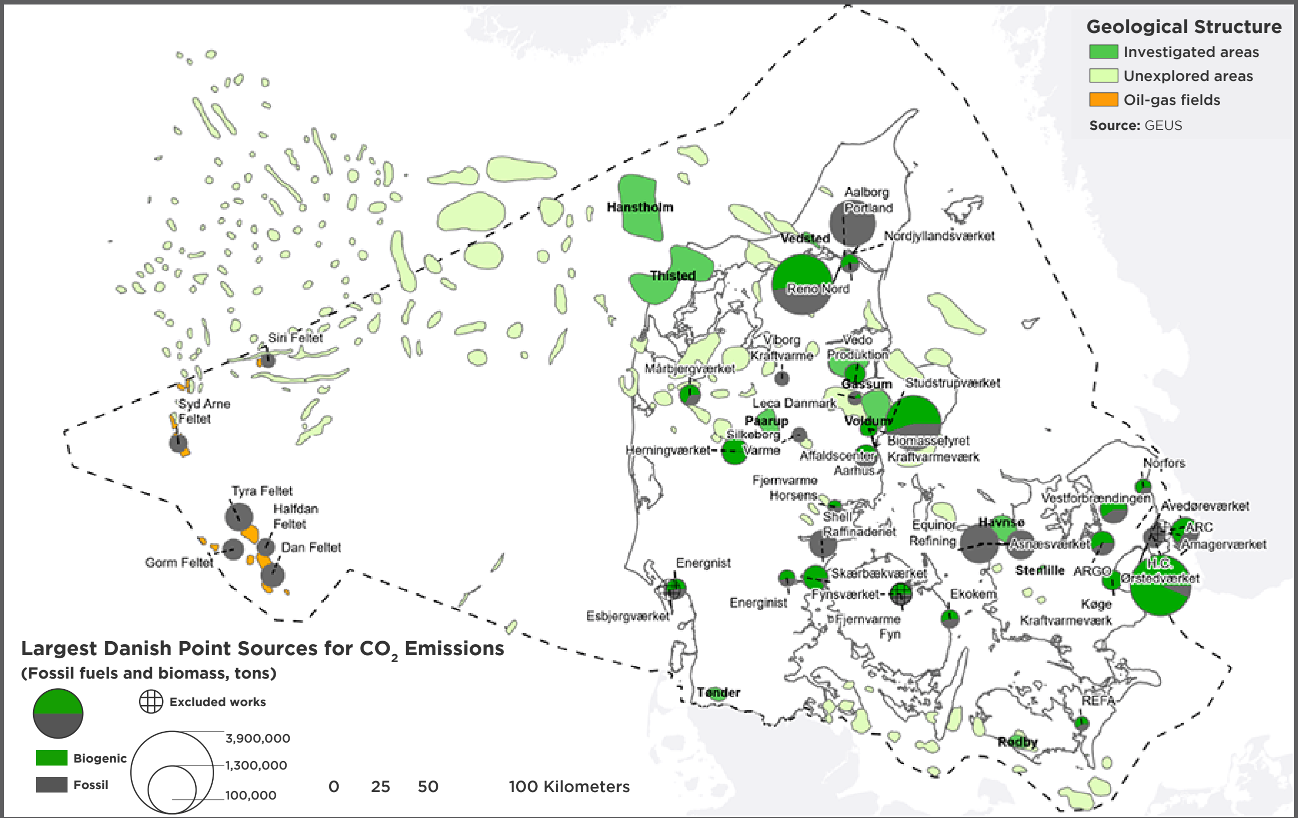


Source: Danish Energy Agency

Ample Storage Drives Deep Interest in CCS Infrastructure

- CCS is a second energy transition technology being aggressively pursued by Denmark.
- In terms of carbon capture potential, Danish point sources could produce 5.4 to 10.8 million metric tons of CO_2 per year by 2040.
  - Danish point sources include industrial, waste incineration, power production, and biogas plants.
  - Most of the potential is concentrated in five clusters around Copenhagen, Aarhus, and Aalborg and in southern Jutland.
- Meanwhile, total storage potential in Danish subsoil is estimated between 12 and 22 billion metric tons of CO_2.
  - Storage opportunities include onshore, nearshore, and offshore opportunities (see Figure 2.6).
  - As of March 2023, three exploration permits have been granted for offshore storage in the northwestern part of the North Sea: two permits are in depleted oil and gas fields, and one is located in a saline aquifer.
  - In addition, preliminary seismic investigations are ongoing at a number of onshore and nearshore geological formations.

Figure 2.6: **Potential CO_2 Storage Options in Denmark**

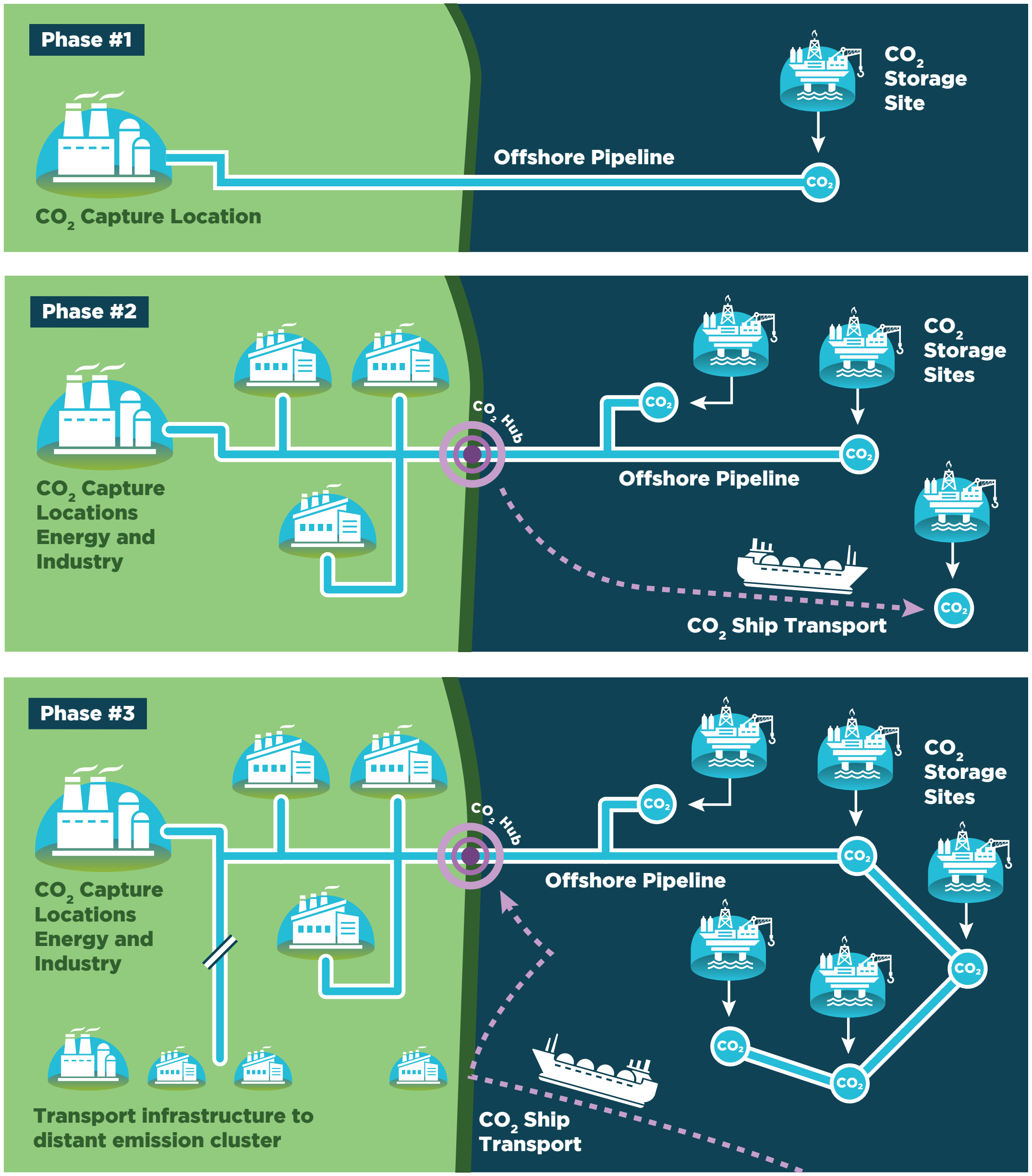


Source: Danish Energy Agency

Ample Storage Drives Deep Interest in CCS Infrastructure (Cont.)

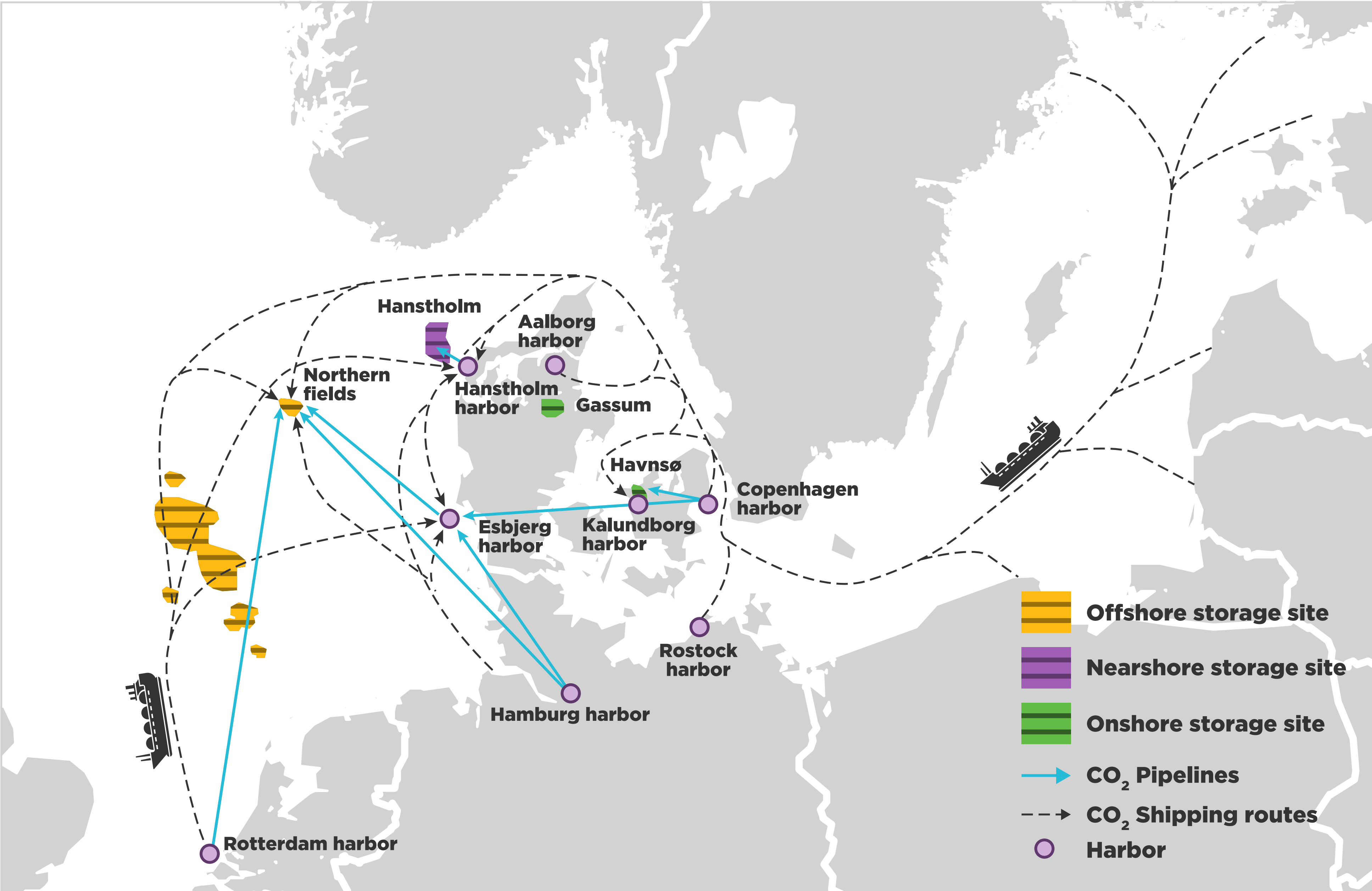
- To kickstart CCS development, Denmark has also established two funds designed to deliver cost-effective GHG reductions that contribute to climate targets.
  - The CCUS Fund is a market-based, technology-neutral fund aimed at supporting carbon capture, utilization, and storage.
  - The Negative Emissions Carbon Capture and Storage Fund will support the capture of biogenic CO_2 with the goal of achieving negative reductions.
  - By permanently storing CO_2 in the subsoil, the two funds are expected to achieve 1.4 million metric tons of CO_2 reductions annually by 2030.
- Becoming a regional leader in CCS is the long-term goal for Denmark, as highlighted in recent regional plans focused on cross-border CO_2 transport and storage infrastructure.
  - In March 2023, a report released by the North Sea Basin Task Force outlined a vision for incremental construction of CO_2 transport and storage infrastructure, including offshore, nearshore, and onshore storage possibilities.
  - Initial activity would connect promising source clusters and storage sites. Future development would connect additional sources and sinks, upgrading pipelines and cluster hubs and adding ship loading and unloading (see Figure 2.7).
  - With ample storage capacity, neighboring countries could transport CO_2 to Danish locations through pipelines, shuttle tankers, sea vessels, and other modes of transport (see Figure 2.8).

Figure 2.7: **Stepwise CCS Infrastructure Development**



Source: North Sea Basin Task Force

Figure 2.8: **Potential CO_2 Pipelines and Shipping Routes to Denmark**



Sources: Ramboll; Danish Energy Agency

Long-Term Vision and Policy Support Drive Clean Energy Innovation in Denmark

- Utility executives participating in the fact-finding mission to Denmark found important lessons in the country's effort to become a regional leader in clean energy.
- Offshore wind and other renewable energy technologies are an important, but broad, economy-wide clean energy transition that requires additional resources, technologies, and expertise.
- Importantly, Denmark enjoys a high level of unanimity in support of clean energy policies. Voters, politicians, business leaders, and the government are aligned in their support for and subsidization of clean energy initiatives.
- As a result, Denmark has enacted a long-term vision and robust policy support to encourage private investment in the emerging renewables, PtX, and CCS technologies.
- Importantly, the Danes see the clean energy transition as both a moral imperative and a business strategy providing significant opportunities to provide relatively cheap, clean energy to the region and export critical technologies.
- In the United States, the passage of the Bipartisan Infrastructure Law and Inflation Reduction Act create similar dynamic in the United States, aligning clean energy policy with industrial policy. The question remains: who will seize the opportunity?

IMPLICATIONS

Denmark is planning an aggressive clean energy transition. While the country plans to rely on traditional resources, such as offshore wind, they are also looking to build an infrastructure and industry in emerging technologies.

In an effort to leverage domestic expertise and resources, there is ambitious focus on PtX and CCS as drivers of long-term economic growth. Denmark acknowledges that long-term success will require these technologies becoming economically competitive. Consequently, the country is pursuing a host of policies to encourage innovation and market development.

Notes:

DKK is an acronym for Danish krone.

Sources:

Danish Energy Agency, "The Power-to-X tender is now open" (April 19, 2023); Danish Ministry of Climate, Energy and Utilities, The Government's Strategy for Power-to-X (2021), at https://ens.dk/sites/ens.dk/files/ptx/strategy_ptx.pdf; Danish Energy Agency, Market Model 3.0: The Electricity Market as the Key to a Climate Neutral Society (2021); Danish Ministry of Climate, Energy, and Utilities, Denmark's Integrated National Energy and Climate Plan (December 2019); Offshore WIND, "Denmark Launches World's First Power-to-X Tender" (April 19, 2023); Hydrogen Central, "Denmark – a New Executive Order Came Into Force That Makes it Possible to Issue Guarantees of Origin for Hydrogen" (July 5, 2023); State of Green, "New Danish government moves forward net-zero climate target to 2045" (December 15, 2022); "Can the North Sea become Europe's new economic powerhouse?" *The Economist* (January 1, 2023).

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Vestas

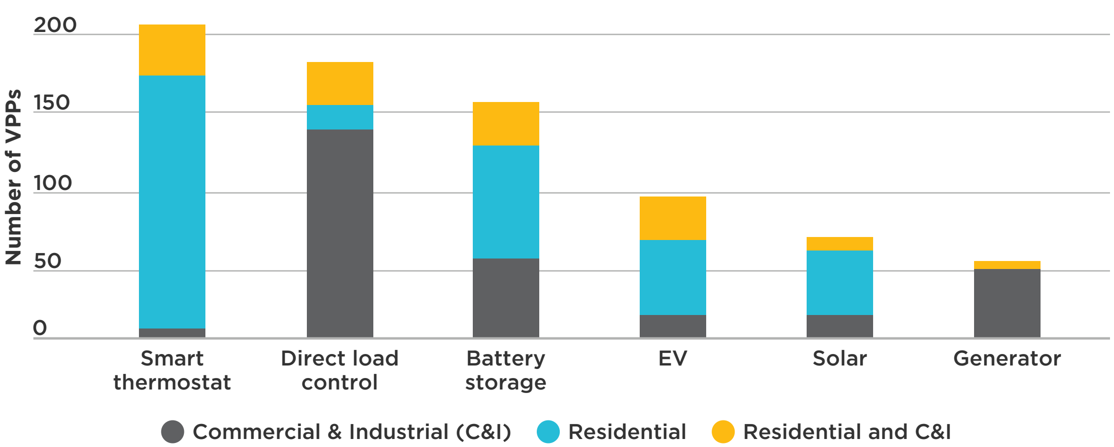
Virtual Power Plants

With widespread adoption, distributed energy resources mature into a flexible grid resource.

Virtual Power Plants (VPPs) Are Proliferating, Providing Grid Services, and Poised for Growth

- Evolving from a legacy rooted in demand response, the term VPP applies to aggregations of distributed energy resources (DERs) that are actively controlled to provide grid services to electric utilities or wholesale markets.
- VPPs include a broad range of technologies, including rooftop solar PV, distributed battery storage, electric vehicles, smart thermostats, smart water heaters, and commercial building automation systems.
- Using a broad VPP definition, Wood Mackenzie estimates that more than 500 VPP projects operate in North America, using an array of technologies (see Figure 3.1). Meanwhile, the U.S. Department of Energy (DOE) estimates current VPP capacity in the United States to be 30 to 60 GW.
- Looking forward, VPPs are set for rapid expansion.
  - RMI estimates VPPs could reduce peak demand in the United States by 60 GW by 2030.
  - With rapid and coordinated action, DOE estimates this figure could be higher, reaching 80 to 160 GW (or 10% to 20% of peak load) by 2030.
- To prepare for this future, electric utilities should evaluate the role and benefits VPPs could provide their service territories.

Figure 3.1: **Number of North American VPPs Utilizing DER Technologies (by Type)**



Source: Wood Mackenzie, North America Virtual Power Plant Market: 1H 2023

KEY TAKEAWAYS

Electric utilities are enrolling customers and deploying DERs as VPPs in large numbers across the country.

Implementation of FERC Order 2222 will expand market access for VPPs by allowing aggregated DERs to participate in wholesale markets.

Additional drivers encouraging VPP growth include the success of early projects, expanding DER capacity and technologies, extended federal tax credits, and growing reliability concerns.

Utilities interested in introducing or expanding VPPs should develop a strategic plan focused on assessment, stakeholder engagement, and DER investments.

With an Ability to Be Tailored, VPPs Offer a Broad Value Proposition

- In a recent report, DOE notes: "VPPs are a tool used for flexing distributed demand and supply resources with a level of dexterity that has historically only been possible in flexing centralized supply."
  - Based on the availability of DERs in a service territory, a VPP can function as demand, generation, and storage.
  - This makes VPPs highly configurable and capable of being designed to deliver grid services tailored to a specific time, location, and scale.
  - By being dynamic and flexible, DERs can be used to:
    - Shift demand from peak to off-peak hours
    - Shed demand on the grid during supply shortages (by reducing consumption or providing on-site energy)
    - Reshape and reduce baseload consumption
    - Provide ancillary services to satisfy the needs of the distribution or transmission grid
  - In addition, a VPP can be adapted over time to meet the changing needs of the electric grid.
- VPPs can reduce grid operating costs and offer a host of additional benefits.
  - A recent Brattle analysis concluded that a VPP consisting of residential DERs (i.e., thermostats, water heaters, EV chargers, and behind-the-meter batteries) could provide peaking capacity with a net cost 40% to 60% lower than traditional alternatives (i.e., natural gas peaker plant and utility-scale batteries).
  - With the ability to perform a wide array of functions, VPPs can provide broad value to the electric system, grid operators, local communities, and individual customers (see Figure 3.2).

Figure 3.2: **VPP Value Proposition**

Resource Adequacy
- Integrate distributed generation and storage capacity
- Shift demand to follow supply

Affordability
- Defer grid capex (generation, T&D)
- Avoid fuel costs
- Compensate consumers and businesses

Reliabilty and Resilience
- Integrate back-up power
- Eliminate single point of failure

Decarbonation and Air Pollution Reduction
- Add distributed renewable generation
- Reduce curtailment of renewables
- Reduce reliance on fossil fuels

T&D Infrastructure Relief
- Increase efficiency by smoothing peaks
- Alleviate congestion with local dispatch

Community Empowerment
- Enable consumers to optimize energy cost, use, and source
- Retain and create good jobs

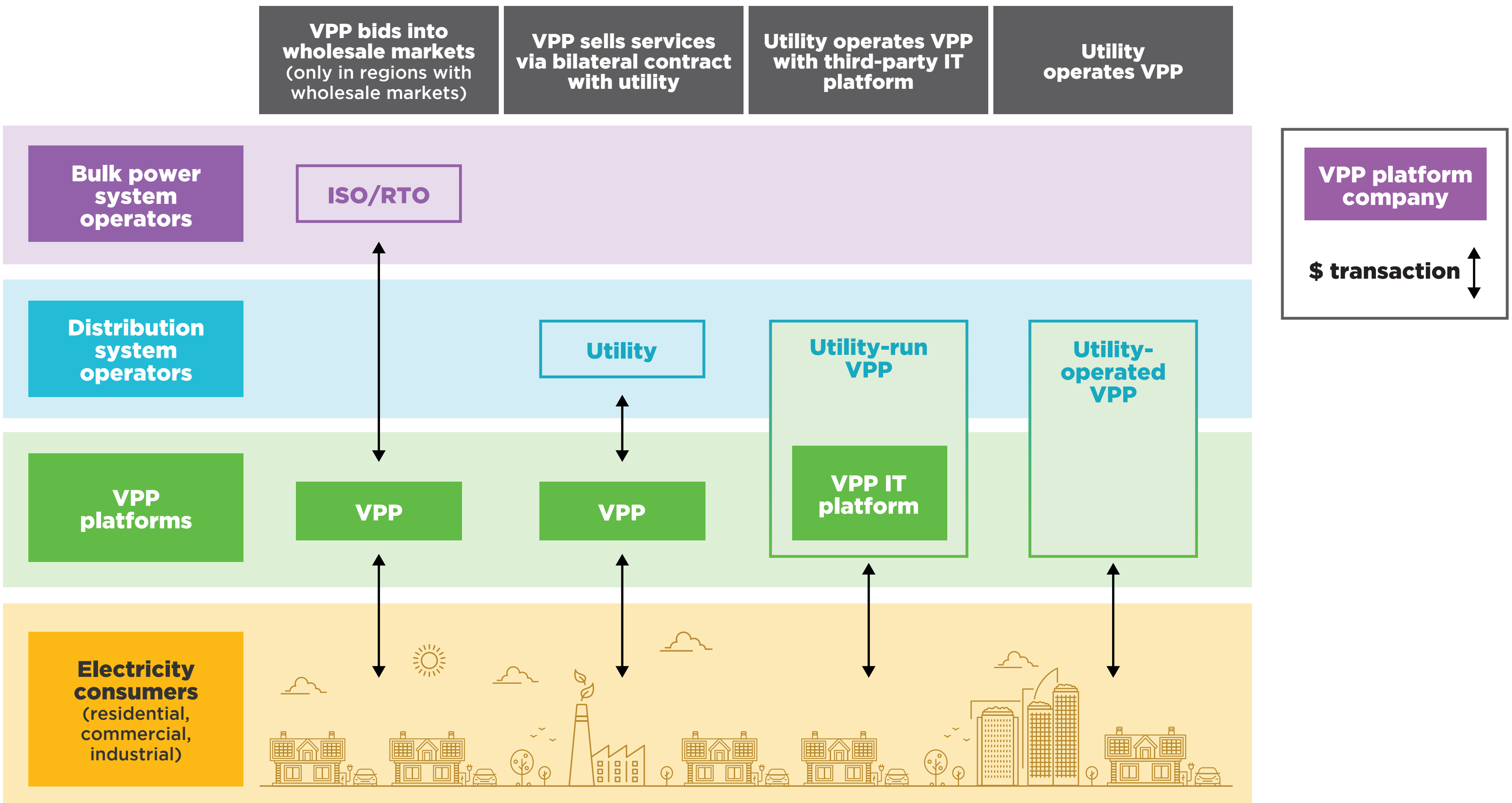
Versatility and Flexibility
- Customize design to fit grid needs
- Reconfigure as needs evolve

Source: DOE VPP Liftoff Report

With an Ability to Be Tailored, VPPs Offer a Broad Value Proposition (Cont.)

- VPPs recruit DER owners in a variety of participation models that offer rewards for contributing to efficient grid operations (see Figure 3.3).
  - **Market Participant:** A VPP aggregator enrolls members and dispatches the VPP to provide capacity, energy, and ancillary services to the wholesale market in response to price signals from the market operator.
  - **Retail:** A distribution utility enrolls customers to establish the VPP and controls the VPP directly to meet system needs. The utility may run the VPP project in-house or partner with a third-party service provider.

Figure 3.3: **VPP Market Participation Model**



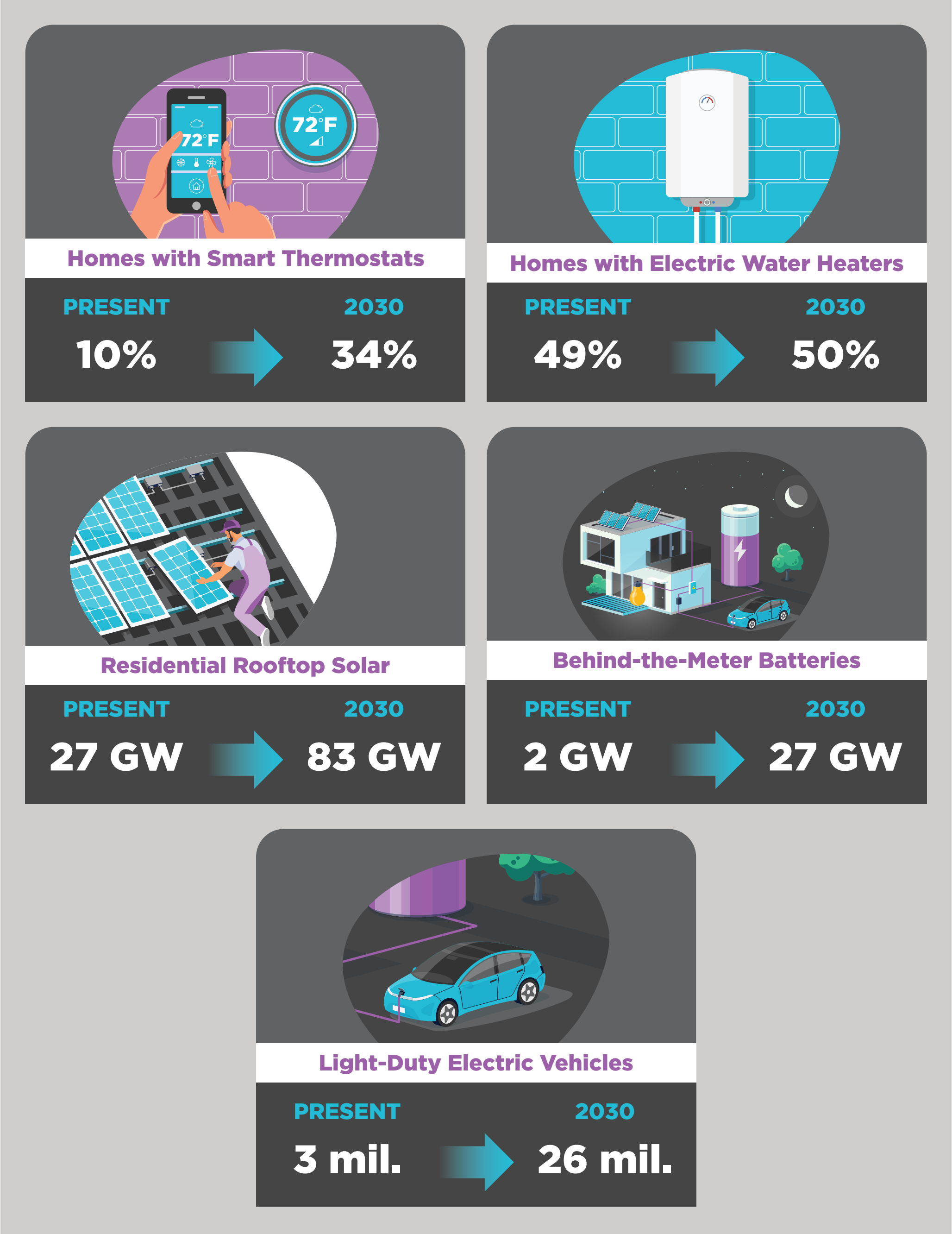
Source: DOE VPP Liftoff Report

Multiple Drivers Create Strong Tailwinds for VPP Growth, But Implementation Hurdles Remain

- Continued growth of VPPs will depend upon some key drivers:
  - **Early Success:** Pilot programs and early adopters have demonstrated value and allowed third-party service providers to refine and enhance offerings.
  - **Diverse Technology:** A growing number of technologies may contribute to VPPs. This may include traditional demand response technologies (e.g., smart thermostats) and emerging technologies (e.g., bi-directional charging of electric vehicles).
  - **Federal Tax Credits:** Following passage of the Inflation Reduction Act, multiple technologies (i.e., solar PV, battery storage, electric vehicles, and heat pumps) are eligible for tax credits through 2032.
  - **Critical Mass:** The sheer number of DERs available to participate in VPPs has rapidly expanded in recent years.
    - **Solar PV:** More than four million residential solar PV systems exist in the United States—more than 700,000 systems were installed in 2022.
    - **Storage:** More than 240,000 residential energy storage systems exist in the United States—more than 90,000 systems were installed in 2022.
    - **Electric Vehicles:** The United States is on track to sell one million EVs in 2023, and more than half of passenger car sales could be electric by 2030.

  Strong growth is forecasted for these and other DERs through 2030 (see Figure 3.4).

Figure 3.4: **Projected Growth of Select DERs**



Source: The Brattle Group

Multiple Drivers Create Strong Tailwinds for VPP Growth, But Implementation Hurdles Remain (Cont.)

- **Market Access:** In September 2020, the Federal Energy Regulatory Commission (FERC) issued Order 2222 requiring regional transmission organizations (RTOs) and independent system operators (ISOs) to amend rules to allow heterogenous DER aggregations in wholesale markets (see Figure 3.5).
  - FERC has fully accepted one compliance plan, partially accepted three compliance plans, and not yet commented on two compliance plans. Compliance dates range from November 2024 to October 2029 (see Figure 3.6).
  - In several concurring statements, commissioners have noted concerns that implementation of Order 2222 will negatively impact state regulation of the distribution system.
  - Implementation challenges and design questions being addressed in implementation plans include defining eligible markets, determining location requirements (i.e., feasibility of multinodal VPPs), and securing FERC approval of tariffs before developing software.
- **Reliability Concerns:** Resource capacity shortfalls and energy risks are both cited as concerns in the most recent Long-Term Reliability Assessment published by the North American Electric Reliability Corporation (NERC). The report specifically notes:

> "DER aggregators will also play an increasingly important role for bulk power system (BPS) reliability in the coming years. Increasing DER participation in wholesale markets should be considered in connection with potential impacts to BPS reliability, contingency selection, and how any reliability gaps might be mitigated."

NERC also notes the need for DER data sharing, models, and information protocols to support BPS planners and operators.

Figure 3.5: **Tariff Revisions Required by FERC Order 2222**

In Order 2222, FERC directs RTOs and ISOs to:

1. Allow DER aggregations to participate directly in markets and establish DER aggregators as a type of market participant
2. Allow DER aggregators to register DER aggregations under one or more participation models that accommodate the physical and operational characteristics of the DER aggregations
3. Establish a minimum-size requirement for DER aggregations that does not exceed 100 kW
4. Address locational requirements for DER aggregations
5. Address distribution factors and bidding parameters for DER aggregations
6. Address information and data requirements for DER aggregations
7. Address metering and telemetry requirements for DER aggregations
8. Address coordination between the RTO/ISO, the DER aggregator, the distribution utility, and the relevant electric retail regulatory authorities
9. Address modifications to the list of resources in a DER aggregation
10. Address market participation agreements for DER aggregators

Source: FERC Order 2222

Figure 3.6: **Status of FERC Order 2222 Implementation**

CAISO

CURRENT STATUS

- In May 2023, FERC issued an order fully approving CAISO's compliance plan.

COMPLIANCE

Initial Filing: July 19, 2021

Deadline: November 1, 2024

NYISO

CURRENT STATUS

- In June 2022 and April 2023, FERC issued orders partially accepting NYISO's compliance plan.
- In May 2023, NYISO submitted an additional compliance filing.
- FERC subsequently accepted tariff revisions, but NYISO must still work with stakeholders to develop market rules for ancillary service.

COMPLIANCE

Initial Filing: July 19, 2021

Deadline: December 31, 2026

PJM

CURRENT STATUS

- In March 2023, FERC issued an order partially accepting PJM's compliance plan.
- PJM has submitted subsequent compliance filings; FERC has yet to comment on these filings.

COMPLIANCE

Initial Filing: February 2022

Deadline:

- PJM requested an indefinite compliance timeline to allow for software development.
- Date is subject to FERC issuing approval.

ISO-NE

CURRENT STATUS

- In March 2023, FERC issued an order partially accepting ISO-NE's compliance plan.
- In July 2023, ISO-NE sued after a rehearing request was denied following 30 days without a FERC response. Issues raised in the rehearing request related to the timing of participation in forward capacity auctions and the party responsible for reporting metering data to the ISO.
- Separately from these issues, ISO-NE submitted subsequent compliance filings.
- In October 2023, FERC issued an order providing additional guidance to ISO-NE.

COMPLIANCE

Initial Filing: February 2, 2022

Deadline: November 1, 2026

SPP

CURRENT STATUS

- In August 2022, SPP submitted additional details following a FERC request for more information.
- FERC has yet to comment on SPP's compliance plan.

COMPLIANCE

Initial Filing: April 28, 2022

Deadline:

- Proposed Q3 of 2025
- Date is subject to FERC issuing a final order

MISO

CURRENT STATUS

- In October 2022, MISO submitted additional details following a FERC request for more information.
- In October 2023, FERC issued an order partially accepting MISO's compliance plan.

COMPLIANCE

Initial Filing: April 14, 2022

Deadline:

- Proposed October 1, 2029
- Subject to change as FERC requested a more timely compliance date in its order.

Source: ScottMadden research

Figure 3.7A: **Select Operating and Planned VPP Projects (Western U.S.)**

Onsemble: Announced $3 million in seed funding in September 2023 and plans to upgrade gas to electric water heaters in exchange for participation in demand management during peak hours. Product testing will occur in three northern California counties.

Pacific Gas & Electric: Partnering with Sunrun to incorporate 8,500 new and existing rooftop solar PV and battery systems as part of a 34 MW VPP. Storage systems discharge power to the grid each evening from August through October. Customers receive an upfront payment of $750 and a free smart thermostat for participating.

San Diego Gas & Electric: A pilot VPP leveraging multiple brands and types of devices successfully provided support to the grid during three peak events in August 2023. The VPP leverages customer-owned smart thermostats, rooftop solar, energy storage, and other connected resources such as water pumps.

Southern California Edison: Partnering with Tesla, the Emergency Load Reduction Program provided up to 33 MW during an extended heat wave in 2022. The capacity was aggregated from more than 4,600 participants.

Rocky Mountain Power: Utah customers can receive an upfront incentive and ongoing bill credits to install batteries integrated with customer-sited solar PV. Excess solar charges the batteries, which then provides energy to the electric grid. Approximately 3,500 customers have signed up for the program.

Xcel Energy: The Renewable Battery Connect program compensates residential and business customers in Colorado with up-front and annual incentives for access to solar-charged batteries. Participating customers agree to allow Xcel Energy to charge or discharge up to 60% of their batteries up to 60 times per year.

Texas: The Aggregated Distributed Energy Resource (ADER) Pilot Project went live in August 2023 with Tesla Energy connecting two VPPs consisting of Powerwall customers located in Houston and Dallas, respectively. The ADER Pilot Project is authorized to add up to 80 MWs of DERs across multiple aggregators.

Hawaiian Electric: Signed a $25 million contract with Swell Energy for an 80 MW VPP in January 2021. Under the contract, Swell aggregates and dispatches a fleet of approximately 6,000 mostly residential solar-powered batteries as a single grid resource.

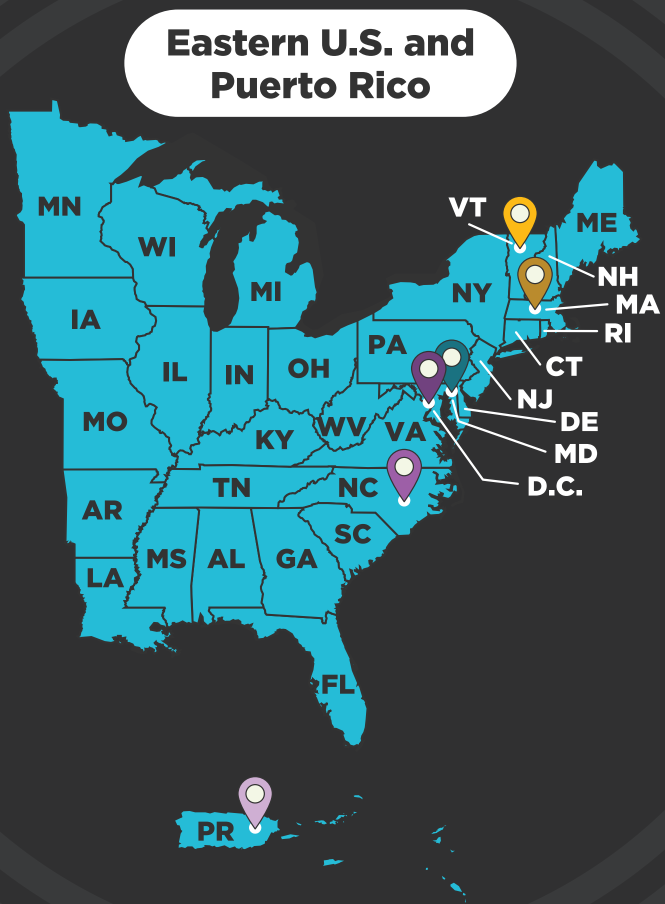
Source: ScottMadden research

Figure 3.7B: **Select Operating and Planned VPP Projects (Eastern U.S. and Puerto Rico)**

Department of Energy: In April 2023, the Loan Program Office announced a conditional commitment for a $3 billion partial loan to Sunnova Energy Corporation. Funds would support Project Hestia, which will target disadvantaged communities and homeowners with lower credit ratings for rooftop solar PV, battery storage, and VPP-ready software.

Duke Energy: In North Carolina, Duke Energy proposed a solar-plus-storage pilot program, allowing seasonal access to customer batteries. Each year, the utility may access batteries 18 times between December and March, nine times between March and September, and on nine other occasions. The company expects to enroll up to 3,500 homes within five years.

Puerto Rico: In November 2022, the Puerto Rico Electric Power Authority selected Sunrun to develop a 17 MW VPP. Expected to be operational in 2024, the project will consist of 7,000 rooftop solar-plus-battery systems. Tesla Energy is also considering using 350 MW of Powerwall capacity installed on the island to form a VPP.



Green Mountain Power (GMP): Roughly 4,800 batteries located at the homes of 2,900 customers provide energy during peak demand periods. In August 2023, GMP received approval to expand the Tesla Powerwall program. The program, which leases batteries to customers, had a waitlist extending into 2026.

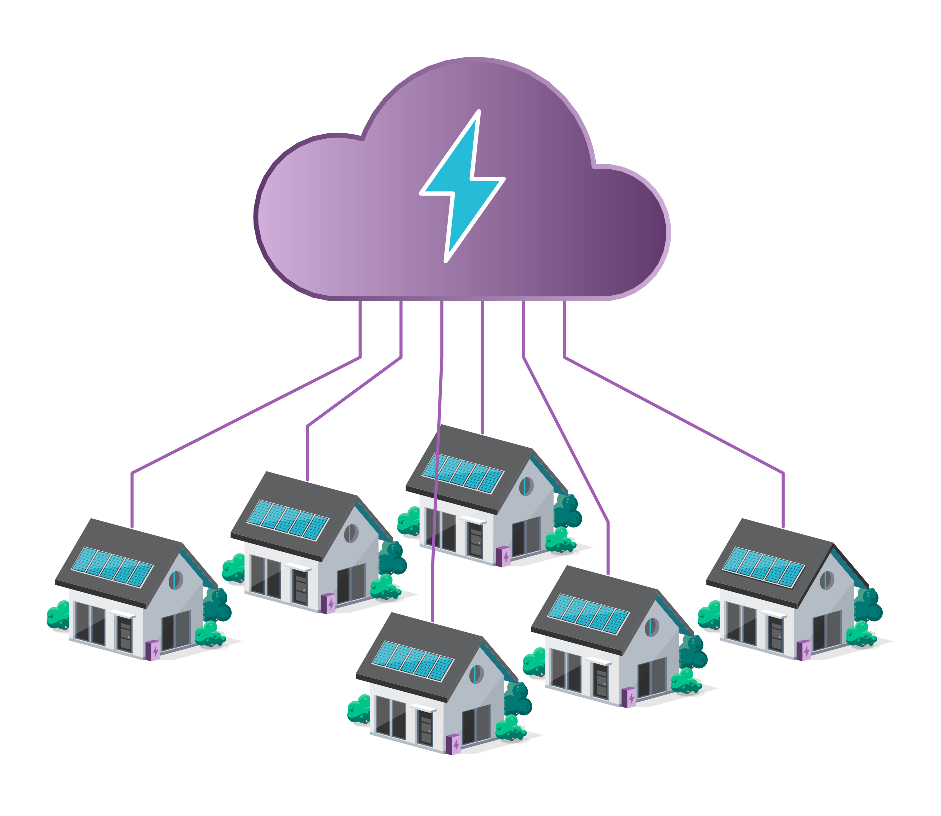
Sunrun: Operates a residential VPP in the wholesale capacity market managed by ISO-NE. In 2022, the VPP shared more than 1.8 GWh of energy back to the grid during its first summer of operation.

Baltimore Gas & Electric: The Smart Residential EV Program is among the first programs to use vehicle-based telematics to support an electric vehicle time-of-use rate. By partnering with WeaveGrid, the program uses the vehicle's computer to measure electricity usage and offer lower-cost off-peak charging to participants.

Source: ScottMadden research

Utilities Can Take Actions Today to Prepare for a Future with More VPPs

- Utilities interested in introducing or expanding VPPs should develop a strategic plan focused on assessment, stakeholder engagement, and proactive DER investments.
- A key first step in developing a strategic plan is assessing how VPPs may provide value within a service territory. Key activities will include:
  - **Assess VPP viability:** Identifying DERs deployed across the system can give utilities a sense of the support VPPs could provide if aggregated. Beyond a current state assessment, developing a granular DER adoption forecast can inform where VPP deployment is most likely to occur.
  - **Identify system needs:** Analyzing system risk during "worst-day" forecasts can provide a utility with an understanding of system constraints and identify load pockets that may overload the system given extreme weather conditions.
  - **Define VPP benefits:** Combining these two inputs (DER forecasts and system needs) can help utilities understand the potential benefits VPPs can provide to the system. With this understanding, utilities can develop planning requirements and compensation frameworks that utilize VPPs as cost-effective tools.
- In addition to the assessment, utilities should engage with regulators and market stakeholders. Key activities include:
  - **Education:** Ensuring regulators understand the viability, functionality, and benefits of VPPs is critical. This education may lead to support for VPP deployments or other key infrastructure investments. A review of current rates may also be needed to ensure DERs are not dually compensated for the same service.
  - **Market engagement:** Establishing relationships with third-party service providers may help utilities understand offerings and encourage collaboration as opportunities arise. This may also inform DER eligibility requirements should VPP enrollment occur in the future.
- Finally, utilities should consider proactive investments that prepare systems for high DER penetrations.
  - If not already in place, investments in advanced meters and advanced distribution management systems may support future DERs and VPPs.
  - Similarly, enhancing cybersecurity protocols can mitigate the risk of security breaches in a future, more decentralized grid.
  - Being proactive can prepare a utility for any administrative or operational burdens and avoid becoming a bottleneck during VPP deployment.



IMPLICATIONS

VPPs have evolved from basic demand response programs to dynamic offerings capable of leveraging a diverse range of technologies, including rooftop solar PV, battery storage, and electric vehicles. These new technologies allow VPPs to provide a broader range of grid services, including energy, capacity, and ancillary services that can be tailored to specific geographic locations and time periods.

The continued expansion of VPPs, including their integration into wholesale markets, could prove useful in ensuring reliability during peak demand periods. Electric utilities will need to develop strategic plans for VPPs to ensure maximum benefit is delivered to the electric grid.

Sources:

DOE, Pathways to Commercial Liftoff: Virtual Power Plants (Sept. 2023); Rocky Mountain Institute; The Brattle Group, "Real Reliability: The Value of Virtual Power" (May 2023); National Renewable Energy Laboratory, A Primer on FERC Order No. 2222: Insights for International Power Systems (Sept. 2021); "FERC Order 2222: Experts Offer Cheers and Jeers for First Round of Filings," Canary Media (Mar. 14, 2022); Pacific Northwest Laboratory, FERC Order No. 2222 and Considerations for Distributed Wind (July 2023); "Texas Hooked up Its First Virtual Power Plants to Help the Grid," Canary Media (August 31, 2023); "Swell Energy Reveals 80-megawatt Virtual Power Plant Contract Win with Hawaiian Electric," Canary Media (January 18, 2021); "Tesla Energy Is Working to Launch a Virtual Power Plant in Puerto Rico," *The San Juan Star* (June 19, 2023); DOE Loan Program Office, "LPO Offers First Conditional Commitment for a Virtual Power Plant to Sunnova's Project Hestia to Support Grid Reliability and Expand Clean Energy Access" (Apr. 20, 2023); Smart Energy International; "Duke Energy Is Starting to Experiment with Virtual Power Plants. What Is That?" *The News & Observer* (July 1, 2023); PV Magazine; Wood Mackenzie; Cox Automotive; Bloomberg News; Inside Climate News; Energy Storage News; Axios; Utility Dive; POWERGRID International; Rocky Mountain Power; Xcel Energy; Green Mountain Power; Sunrun; Tesla; PLMA; Energy Systems Integration Group; ScottMadden research

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Natural Gas Utility Decarbonization

Some states seek to define the future of gas, while utilities desire flexibility and evaluate decarbonization approaches.

Several States Examine Gas Distribution Utilities' Long-Term Future

- As of late August 2023, 12 states and the District of Columbia have initiated proceedings to consider the long-term role of retail natural gas and related infrastructure (see Figure 4.1). These proceedings are largely related to decarbonization or GHG-reduction targets already in place in those states.
- Cases arise in different contexts, and one more docket may be coming. In Maryland, the Office of People's Counsel has challenged gas local distribution company (LDC) proposals to continue replacing aging gas distribution pipeline at an accelerated pace under a 10-year-old rider framework, which does not include expanding service for new customers. The PSC is considering whether to start a formal proceeding.
- These proceedings have led LDCs and regulators to consider various approaches to decarbonizing gas systems and alternative technologies and fuels.

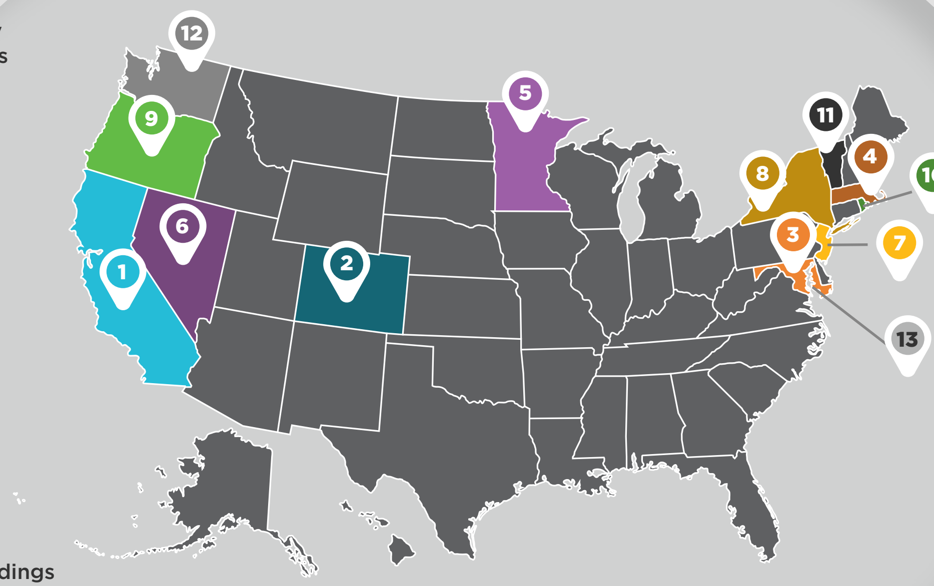
KEY TAKEAWAYS

"Future of gas" proceedings have been initiated in some states that have set energy system decarbonization goals.

Gas LDCs are looking at a variety of pathways to reduce carbon intensity in the gas system and in end-use consumption. The pace and scale of proposed changes to business-as-usual must balance competing objectives: safety, reliability, and stranded costs vs. rapid transition under state climate targets. Portfolio-based approaches may provide optionality, reduce cost, and increase feasibility of achieving emissions reduction objectives.

In tandem, regulators and utilities are considering new regulatory designs to effectively deploy recommended initiatives.

Figure 4.1: **"Future of Gas" Proceedings as of August 31, 2023**



1 CALIFORNIA
Rulemaking: Establish policies, processes, and rules to ensure safe and reliable gas systems in California and perform long-term gas system planning launched in Jan. 2020

2 COLORADO
Rulemaking: Required gas utilities to submit plans for clean heat and modernization of gas programs to achieve 22% emissions reduction by 2030. Final decision issued Dec. 1, 2022

3 MARYLAND
Case: PSC has opened a case in response to Office of People's Counsel objection to continued accelerated replacement of natural gas infrastructure

4 MASSACHUSETTS
Investigation/Scenario Analysis: Investigating function that gas will serve in reaching the state's goal of net-zero GHG emissions by 2050

5 MINNESOTA
Investigation: Evaluation of changes to the natural gas utility regulatory and policy structures to meet state GHG goals, including potential "innovation plans" that consider gas alternatives

6 NEVADA
Investigation: PUC opened investigation regarding long-term planning for natural gas utility service in Nevada in 2021

7 NEW JERSEY
Investigation: BPU directed staff to engage with stakeholders to investigate how the gas industry can meet the state's 50% reduction in emissions by 2030 goal

8 NEW YORK
Rulemaking: Launched in May 2020 to develop gas moratoria protocol and align gas system planning with New York's GHG emissions targets

9 OREGON
Investigation/Scenario Analysis: Proceeding to solicit natural gas utilities in Oregon to create decarbonization plan

10 RHODE ISLAND
Investigation: Investigation into the future of the regulated gas distribution business in Rhode Island in light of 2021 legislation targeting economy-wide net-zero by 2050

11 VERMONT
Case: PUC opened two proceedings to begin the process of designing a potential Clean Heat Standard program as directed by Act 18 of 2023

12 WASHINGTON
Investigation/Scenario Analysis: Examine feasible and practical pathways for investor-owned electric and natural gas utilities to contribute their share to GHG emissions reductions

13 WASHINGTON, DC
Investigation: Ongoing activity related to LDC climate business plans and alignment of DC climate goals

Sources: Building Decarbonization Coalition; Maryland PSC; ScottMadden research

Many and Varied Questions Characterize Gas Decarbonization Proceedings

- Future of gas proceedings vary by jurisdiction, but most explore solutions to mitigate bill impacts and balance competing objectives: safety, reliability, and stranded costs vs. rapid transition under state climate targets.
- In some cases, regulators are investigating decarbonization options through multiple proceedings. New York, for example, has two ongoing gas-related proceedings:
  - First, the New York PSC updated its gas system planning process for LDCs (effective May 2022), accounting for GHG emissions (demand- and supply-side), alternative fuels (e.g., renewable natural gas, or RNG), and non-pipes alternatives, among other things. That proceeding (Case No. 20-G-0131) continues, addressing other gas planning issues.
  - Second, also in May 2022, the PSC initiated another proceeding for gas utility compliance with the state's climate reduction targets of 40%* by 2030 and 85%* by 2050.
    - The proceeding requires development by utilities of a GHG emissions inventory report and directs LDCs to prepare a coordinated, long-term gas sector decarbonization pathway analysis through 2050 and a near-term plan for potential actions through 2030.
    - The pathways study should analyze the scale, timing, costs, risks, uncertainties, and customer bill impacts of achieving significant and quantifiable reductions in GHG emissions from the use of LDC-delivered gas.
  - In parallel with these proceedings, the New York legislature has been active, enacting a requirement—by 2027 zero-emissions sources of heat in all new buildings (with some exceptions). The legislature is also considering removing utilities' obligation to serve gas customers.
- The scope of PSC proceedings can be general, covering a few broad matters, or more specific questions to be addressed. Examples of each are shown in Figures 4.2A-B.

Figure 4.2A: **New Jersey Gas Planning Docket Scoping Considerations (Docket No. GO23020099)**

NEW JERSEY GAS PLANNING DOCKET SCOPING CONSIDERATIONS (DOCKET NO. GO23020099)

- Consider **competitive market mechanisms** to drive the lowest-cost methods for reducing total greenhouse gas emissions associated with the natural gas sector, including but not limited to adoption of a **"clean heat" standard**
- Ensure **reliable operation and long-term financial viability** of LDCs and the business model needed to keep the **gas system intact** while accounting for a **shrinking customer base**, while growth assumptions and peak usage calculations take into account decarbonization policies and minimize investment in new infrastructure to **reduce risk of stranded asset costs**
- Consider **alternative programs and investments** that could promote jobs such as **converting existing pipeline infrastructure** to provide decarbonized heating and cooling
- **Eliminate subsidies** that encourage unnecessary investment in natural gas infrastructure that is likely to result in stranded costs to customers
- Consider **long-term impacts on customers (esp. low income)** who fail to or are unable to switch away from natural gas and ways to **reduce barriers to transition**
- **Electric grid readiness** to handle electrification of building heating and cooling as well as transportation, including recommendations for shifting investment funding from gas to electric system infrastructure upgrades

Note: Bold emphasis added, not in original.

Source: New Jersey Board of Public Utilities

Figure 4.2B: **Rhode Island PUC Staff Future of Gas Draft Scope (Docket No. 22-01-NG)**

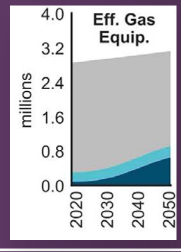
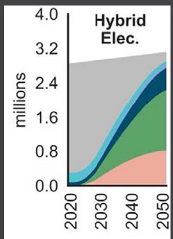
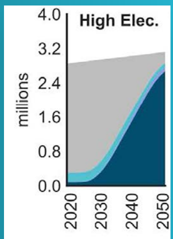
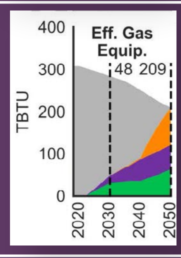
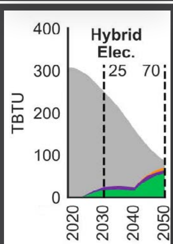
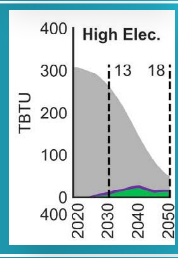
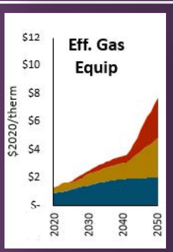
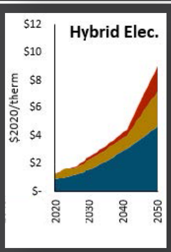
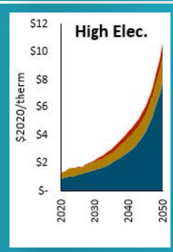
RHODE ISLAND	
POLICY ANALYSIS	▪ Technical requirements of the RI 2021 Act on Climate (Act) ▪ Emissions policy requirements of the Act ▪ Statutory, regulatory, or stakeholder requirements and/or preferences exist that represent constraints on possible pathways for meeting the requirements of the Act
TECHNICAL ANALYSIS	▪ Infrastructure and non-infrastructure options that exist for reducing emissions from the gas system ▪ Scenarios for (all) sector-level emissions that will allow RI to meet the emissions-reduction mandates of the Act ▪ Outputs of the Technical Analysis that will inform the Policy Development phase ▪ Assumptions and inputs are critical to the outputs of the Technical Analysis ▪ Requirements and/or preferences that represent constraints on possible pathways
POLICY DEVELOPMENT	▪ Goals of the gas system absent the Act and how they were developed ▪ Current business-as-usual status of the gas system ▪ Processes that affect procurement of gas, investment in the gas system, and spending on operation and maintenance ▪ Principles and policy the PUC (and regulatory commissions generally) uses in making decisions on procuring gas and spending on the system ▪ Values not considered in the current regulation of the LDC business that should be considered in light of the Act ▪ Goals for the gas system are consistent with the Act and utility law ▪ Ratemaking principles that support or hinder achieving goals ▪ Existing mechanisms for gas system spending (including investment, O&M, and commodity procurement) are consistent or inconsistent with the purposes of the Act ▪ Mechanisms that could be created to enable decreased emissions from the gas system

Source: Rhode Island Public Utilities Commission

Decarbonization Pathways Involve Multiple Options and Trade-Offs

- Several decarbonization proceedings require LDCs to consider pathways—i.e., a series of assumption-based intermediate- to long-term regulatory mechanisms and programs—that comprise a coordinated strategy to achieve targeted GHG reductions. The pathways may contain a spectrum of options, ranging from options that include continued utilization of natural gas infrastructure to options that include full electrification solutions (Figure 4.3).
- Decarbonization measures are not mutually exclusive but may vary in matter of degree, depending upon cost, bill impact, customer preferences, technology maturity and effectiveness, regional suitability, and infrastructure readiness, among other factors. Figure 4.3 illustrates a continuum of pathways that vary by level of ongoing gas system utilization. Those pathways, in turn, rely upon technologies that have potential advantages and disadvantages (Figure 4.4).
- Because of the current early stage of decarbonization actions and uncertainties with respect to its course, gas sector strategies are promoting portfolio-based approaches using a diverse set of strategies and technologies. For example, the Decarbonization Pathways report in Massachusetts' investigation of the role of LDCs (D.P.U. 20-80) underscores the benefits of this diversified approach. It demonstrates that employing a portfolio-based strategy may mitigate the cost and feasibility risks of the transition, in contrast to scenarios relying solely on a single technology or strategy (see Figure 4.3).
- In considering decarbonization alternatives, LDCs are looking across activities in the supply, distribution, and end-use of natural gas. The initiatives include an array of actions (see Figure 4.5), including:
  - Policy and reporting changes
  - Commodity substitution
  - Infrastructure upgrades
  - New programs
- All initiatives require changes in regulatory design to establish funding and cost-recovery mechanisms, customer service standards and procedures, guidance for approval of pilot programs, and performance metrics. Some can be done within existing PUC jurisdictional authorities, while others may require more significant changes such as enabling legislation or modifications to existing utility statutes.

Figure 4.3: **Selected Decarbonization Options (Massachusetts Example) (2020–2050)**

	Continued Utilization of Natural Gas Infrastructure (Efficient Gas Equipment Scenario)	**Hybrid Electrification Approach**	**Reduced Utilization of Natural Gas Infrastructure** (High Electrification)
Residential Space Heating Stocks by Scenario, Emphasis on Electrification	• Continued reliance on gas heating systems 	• Reliance on electric/gas hybrid heating systems 	• High reliance on electric heating 
Gas Throughout and Composition over Time (TBTU)	• Reliance on RNG (biomethane, synthetic natural gas, hydrogen) 	• Reliance on RNG (biomethane, synthetic natural gas, hydrogen) 	• Reduced reliance on natural gas or renewable gas 
Volumetric Residential Rates, Including Delivery Costs and Commodity Costs over Time ($/Therm)	• Affordability concerns related to commodity costs • Low stranded cost concerns 	• Affordability concerns for natural gas customers • Some stranded cost concerns 	• High affordability concerns for natural gas customers • Stranded cost concerns 

Residential Space Heating Stocks (Top Charts Legend)

- Other
- Electric Resistance
- Ground Source Heat Pump
- Air Source Heat Pump
- Hybrid Gas Electric Heat Pump
- Hybrid Fuel Oil Electric Heat Pump
- Networked Geothermal

Gas Throughput and Composition (TBTU) (Middle Charts Legend)

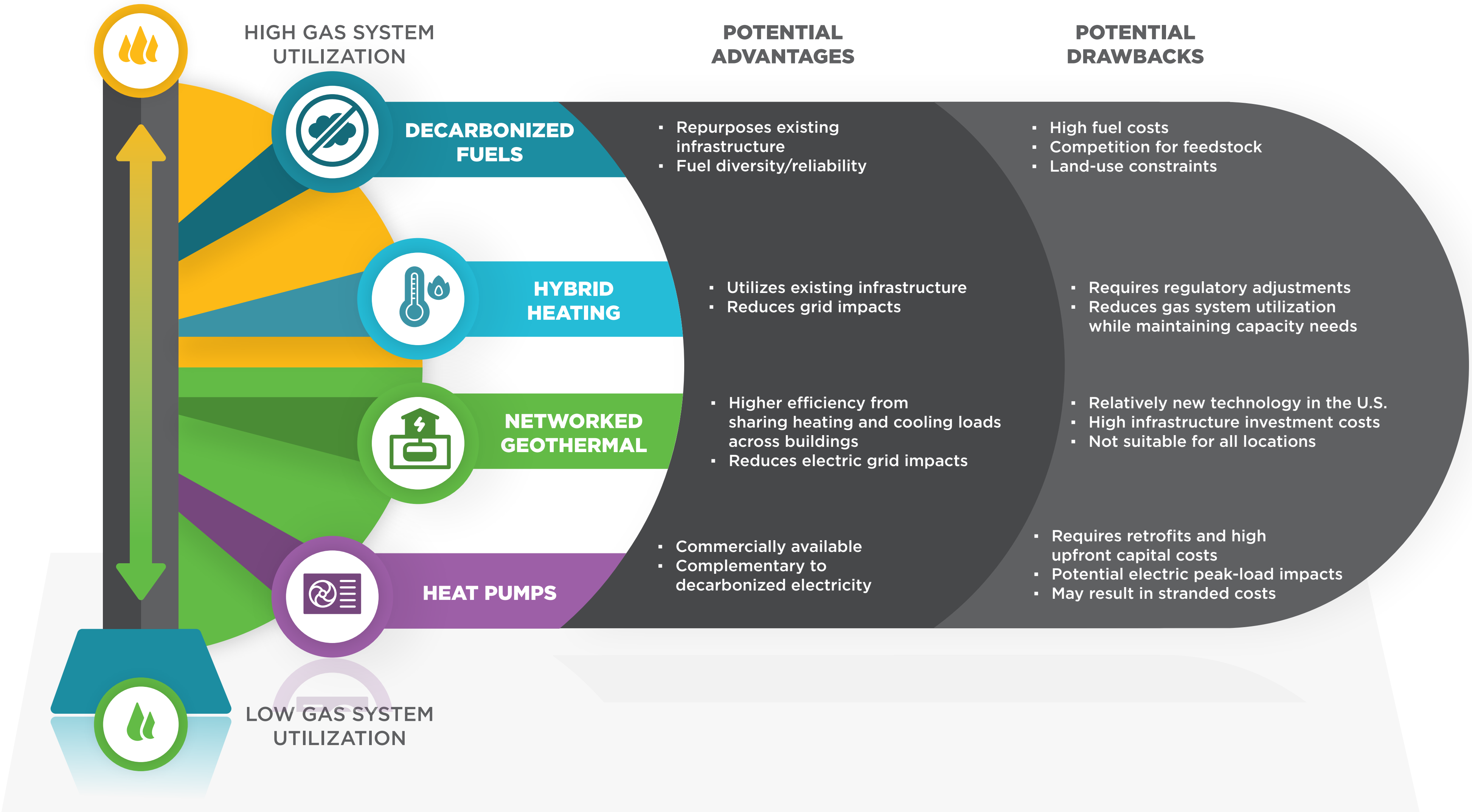
- Natural Gas
- Synthetic Natural Gas
- Hydrogen
- Biomethane

Volumetric Residential Rates ($/Therm) (Bottom Charts Legend)

- Commodity Cost (conservative)
- Commodity Cost (optimistic)
- Delivery Rate

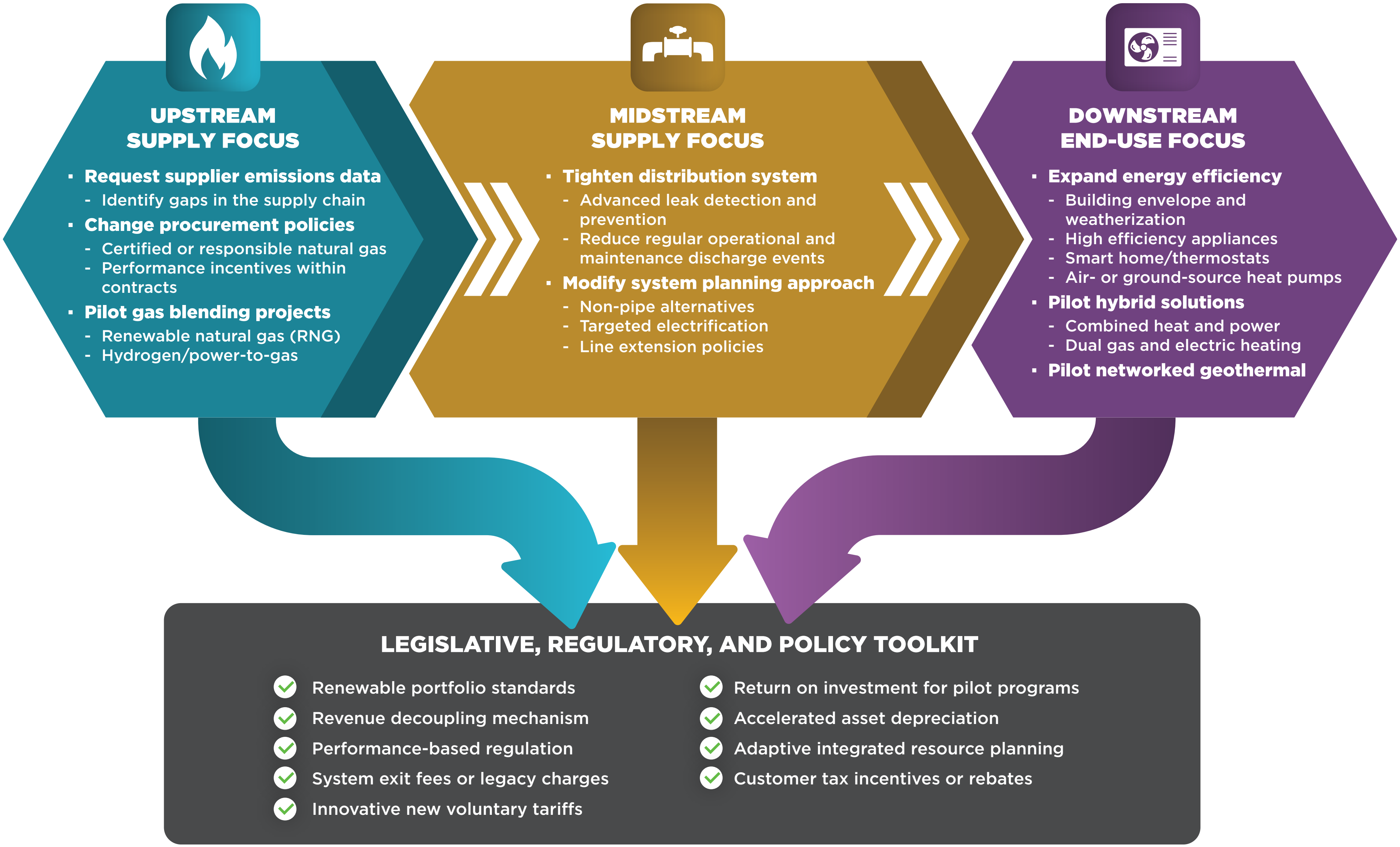
Source: Energy+Environmental Economics/ScottMadden Independent Consultant Report on Decarbonization Pathways, MA D.P.U. Docket 20-80

Figure 4.4: **Selected Decarbonization Technologies for Various Pathways**



Source: ScottMadden, Energy+Environmental Economics analysis

Figure 4.5: **Selected Decarbonization Initiatives by LDC Activity Area**

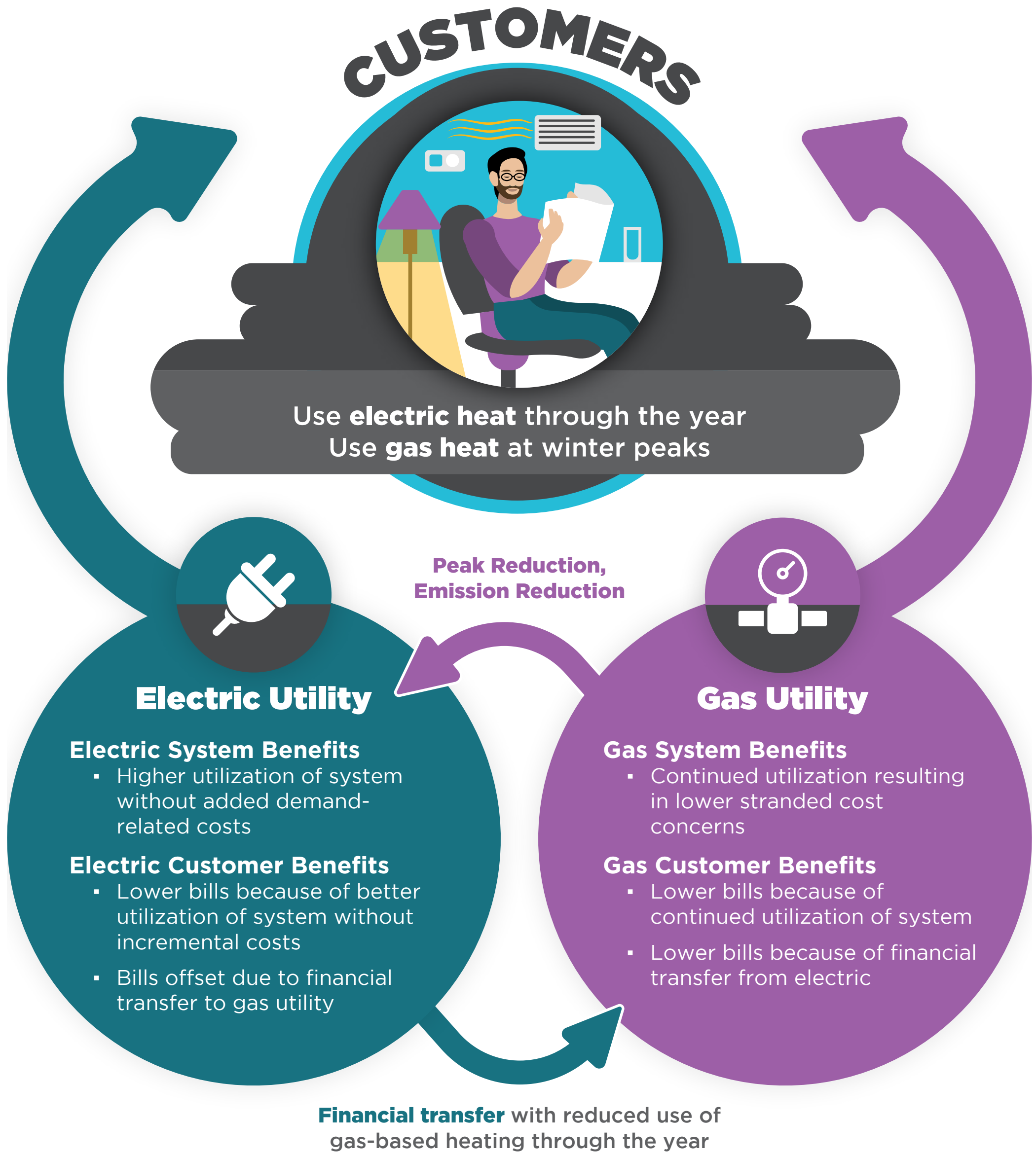


Source: ScottMadden, Energy+Environmental Economics analysis

Several Decarbonization Strategies Attempt to Balance Sometimes Competing Policy Objectives

- There are several decarbonization strategies that may be implementable in the near term such as energy efficiency and renewable natural gas programs.
  - Energy efficiency, through building shell retrofits and energy-efficient equipment, reduces overall energy demand.
  - Renewable natural gas contributes to reduced GHG emissions by being blended into the distribution pipeline and offered to customers through voluntary tariff programs (See Figure 4.8).
- In addition, hybrid heating combines the use of gas infrastructure for peak winter heating demands and electric infrastructure for the remainder of heating needs.
  - This strategy enables gas utilities to continue to use their existing infrastructure, minimize stranded costs, achieve emission reductions, and mitigate near- and long-term bill impact and intergenerational equity concerns.
  - The solution is still being tested in a few jurisdictions and may require coordination between natural gas and electric utility (such as a financial transfer payment) to mitigate bill impacts on natural gas customers (See Figures 4.6 and 4.9).

Figure 4.6: **Hybrid Heating Program Illustration**

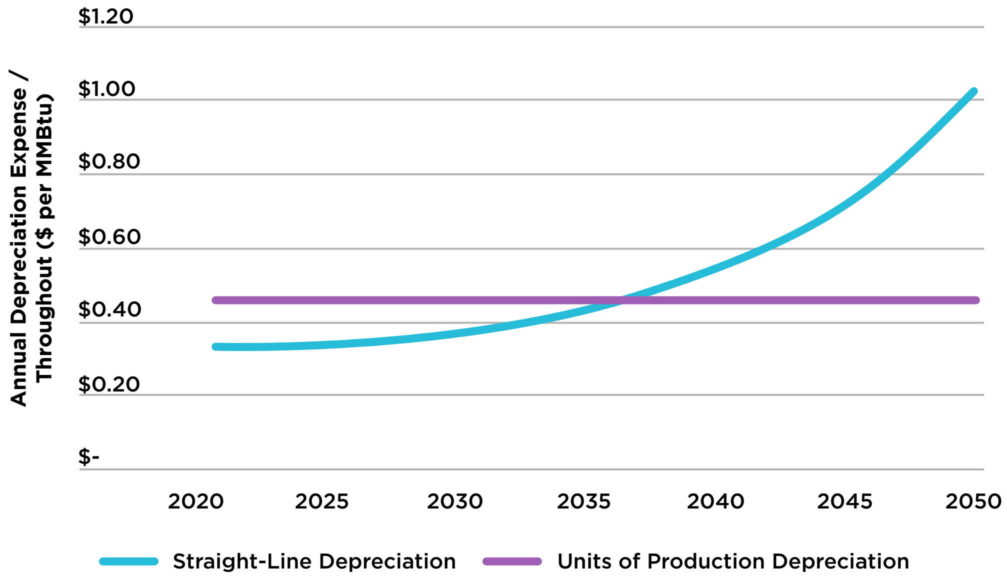


Sources: Hydro-Québec; Énergir

Several Decarbonization Strategies (Cont.)

- Other decarbonization initiatives, such as targeted electrification, involve block- or neighborhood-level electrification to reduce or minimize potential natural gas stranded assets. The solution is also still being tested and has not been attempted at scale. Some challenges include:
  - Requiring 100% customer opt-in and elimination of the obligation to serve
  - Engineering feasibility, especially for replacement projects affecting system reliability
  - Differing planning horizons for gas (immediate safety/ reliability needs) vs. electric
  - Cost-effectiveness changes over time – perhaps lower today but greater in the future
  - Potential for avoided gas system costs to support electrification vs. lower gas rates
- To address long-term affordability and cost recovery concerns, solutions such as accelerated depreciation may need to be considered.
  - Accelerated depreciation, such as the units of production method, attempts to align asset cost recovery with asset utilization. For example, the method may include increased cost recovery in the near term when there is higher system utilization.
  - If (and as) customers start departing the system, the cost recovery also decreases, helping to mitigate customer affordability and intergenerational equity concerns (see Figure 4.7).
  - This alternative depreciation method has been proposed in Massachusetts and California but not yet approved by PUCs as of September 2023.

Figure 4.7: **Annual Depreciation Expense $ per MMBtu Under Straight-Line vs. Units of Production Depreciation Methods (Illustrative)**



Straight-Line Depreciation
- Asset depreciated on a uniform basis each year
- As asset utilization decreases, the $ per unit increases
- In the long term, customers remaining on natural gas system experience large rate increases
- As a result, utility faces stranded cost concerns

Units of Production Depreciation
- Asset depreciation aligned with asset utilization
- As asset utilization decreases, the $ per unit remains the same
- In the long term, customers remaining on natural gas system experience minimal rate increases (from depreciation)
- As a result, stranded cost concerns are mitigated

Source: Energy+Environmental Economics/ScottMadden Independent Consultant Report on Regulatory Designs, MA D.P.U. Docket 20-80

Figure 4.8: **Upstream Initiative Spotlight: Blending Renewable Natural Gas**

What Is Renewable Natural Gas (RNG)?

- RNG is biomethane produced through anaerobic digestion or gasification from sources such as livestock farms, wastewater, or solid waste.
- RNG has lower lifecycle emissions relative to conventional natural gas.
- Other sectors interested in RNG are transportation and power generation.
- Utility contracts are generally long-term (15-20 years) take-or-pay contracts at a fixed-price premium of 3X to 5X natural gas prices.

How It Works

- Several utilities have instituted voluntary tariff programs to offer optional RNG service to customers at a premium, which may include commodity cost or purchase of environmental attributes.
- Other programs blend RNG up to a certain concentration (1% to 2% with some targeting 20%+ longer term) into the gas system.

Regulatory Enablers

- RNG blending is supported by different state policies, including renewable portfolio standards, RNG procurement standards, clean fuel policies, and interconnection standards and tariffs (allowing for recovery of costs for gas conditioning and interconnection).
- Some states have relaxed least-cost mandates to accommodate RNG procurement.
- One utility, Fortis BC, has an RNG tariff for new construction, providing all new residential connections with RNG to meet municipal regulations, provincial building codes, and policy objectives. With no opt-out, customers pay same effective rate as existing customers on similar schedules.

Source: ScottMadden research, S&P Global Market Intelligence

Figure 4.9: **Downstream Initiative Spotlight: Hybrid Heating Programs**

What Is Hybrid Heating?

- Hybrid heating systems consist of both electric- and gas-based systems that are used based upon outdoor temperatures to maximize effectiveness typically by activating gas heating when the electric heat pump does not achieve the desired temperature.
- Configurations can include a heat pump alongside an existing boiler or furnace or a boiler/furnace, heat pump, and controller sold and installed together either as one integrated product or a package.
- Hybrid systems and associated smart control technologies reduce peak power demand, increase resilience, and lower system investment by leveraging existing gas infrastructure.
- Several decarbonization studies have found that hybrid systems in some scenarios have costs savings compared to all-electric scenarios.

Example Deployment

- There are several hybrid heating programs globally.
- For example, Hydro-Quebec and Énergir have a “dual energy” agreement.
  - Residential gas customers in targeted areas are converted to electricity to operate on electric heat during non-peak periods.
  - Financial payment made by electric to gas utility for lost gas revenues (without transfer, gas customers would experience ~5% rate increase).
  - The arrangement incorporates a dual-energy rate structure to encourage switching systems based upon outside temperatures.

Enablers

- Hybrid heating programs may include the following enablers:
  - AMI and supporting billing infrastructure to implement-time-differentiated rates
  - Implementation of smart controls to switch to gas heat during winter peak events and switch to electric heat during off-peak hours
  - Financial transfer from electric utility to gas utility for the winter-peak-reduction benefits provided by the hybrid heating system and/or gas utility lost revenues (e.g., HQD/Énergir program)
  - Innovative rate designs to financially incentivize system switching (e.g., higher electric and lower gas prices during peak events)
  - Equipment incentives to help pay upfront customer costs (e.g., Enbridge Gas $3,200 incentive)
  - Customer awareness and education

Source: ScottMadden research, S&P Global Market Intelligence

IMPLICATIONS

As the natural gas industry transitions toward a decarbonized future, utilities, regulators, and stakeholders will need to consider a portfolio approach with a range of options rather than a single technology or strategy. The portfolio of solutions would need to solve for key transition challenges such as customer affordability (near- and long-term), equity, utility cost recovery, and providing safe, reliable, and affordable energy options.

Note: *From 1990 levels

Sources:

Building Decarbonization Coalition; S&P Global Market Intelligence; State of Maryland Office of People's Counsel, at https://opc.maryland.gov/Gas-Planning-Petition; Maryland Public Service Comm'n Case No. 9707 (filed June 14, 2023); New York Public Service Commission, Case 20-G-0131 – Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, Order Adopting Gas System Planning Process (May 12, 2022); Energy+Environmental Economics/ScottMadden Independent Consultant Report, The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals: Technical Analysis of Decarbonization Pathways, Massachusetts D.P.U. 20-80 (Mar. 18, 2022); Energy+Environmental Economics/ScottMadden Independent Consultant Report, The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals: Considerations and Alternatives for Regulatory Designs to Support Transition Plans, Massachusetts D.P.U. 20-80 (Mar. 18, 2022); Hydro-Québec; Énergir; ScottMadden research

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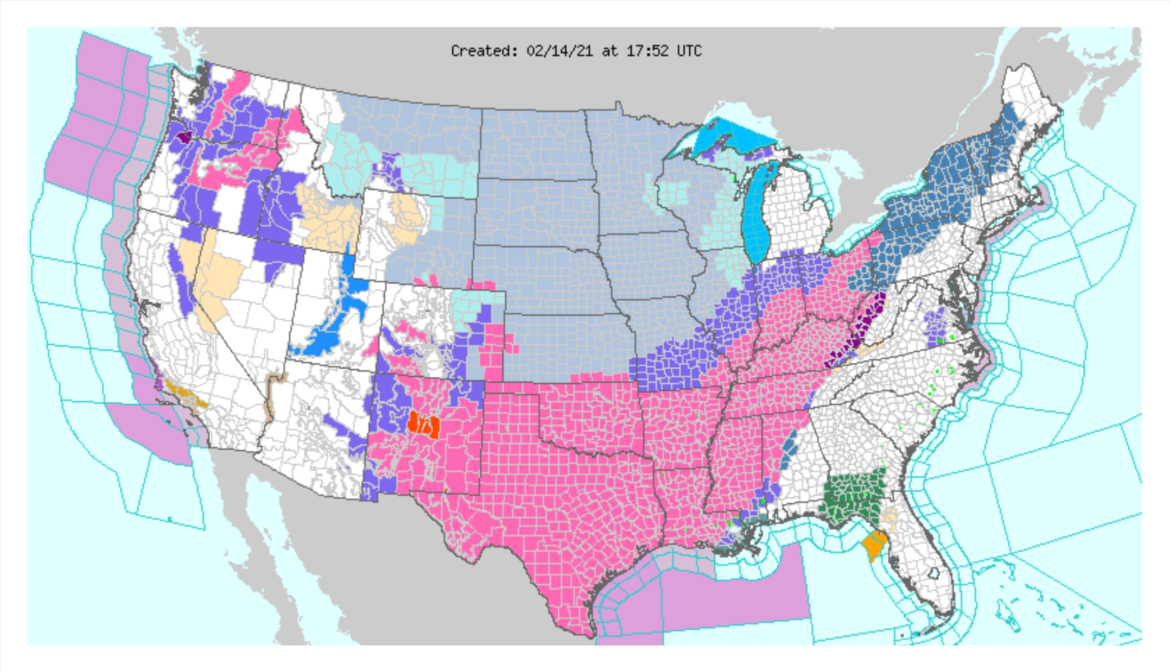
Gas-Power Coordination

Issues persist, but changes in practices prove elusive.

An Energy Industry Panel Convenes after Winter Storm Uri

- In February 2021, a widespread cold event dubbed Winter Storm Uri enveloped the south central United States and Texas. The days-long event brought extreme cold temperatures and freezing precipitation, leading to 34 GW of plant outages at its peak and more than 23 GW of firm load shed. At least 210 people died during the event.
- Key to the failure of generation were outages at natural gas wellheads (production) and gathering and processing facilities that rippled through both gas and power infrastructure.
- FERC and NERC staff issued a report on the event in November 2021, outlining key findings and recommendations. That report suggested holding a forum of representatives of state legislatures and/or regulators with jurisdiction over natural gas infrastructure, in cooperation with FERC, NERC, and the regional entities and natural gas infrastructure entities, to "identify concrete actions to improve the reliability of the natural gas infrastructure system necessary to support the bulk electric system." Some suggested questions for the forum are shown in Figure 5.1 on the next page.
- FERC and NERC leadership wrote a letter in July 2022 to the North American Energy Standards Board (NAESB) to convene the recommended forum. That forum began work in August 2022 and concluded in July 2023.



Source: National Weather Service

KEY TAKEAWAYS

Recent winter storms and related grid challenges have reinforced the interrelationship between the gas and power sectors and need for coordination of operations of those sectors.

A recent year-long NAESB forum provided improvement recommendations, building upon past examinations of the issue. However, there is no clear path forward.

For now, FERC and NERC will continue to focus on the issue, and FERC may address it in a November 2023 technical conference.

Figure 5.1: **Questions for NAESB Gas-Power Forum Posed by FERC and NERC Staff (Nov. 2021)**

Questions for NAESB Gas-Power Forum Posed by FERC and NERC Staff (Nov. 2021)

- Whether and how **natural gas information** could be aggregated on a regional basis for sharing with bulk electric system operators **in preparation for and during events** in which demand is expected to rise sharply for both electricity and natural gas, including whether creation of a voluntary natural gas coordinator would be feasible
- Whether Congress should consider placing **additional or exclusive authority for natural gas pipeline reliability** within a single federal agency, as it appears that no one agency has responsibility to ensure the systemic reliability of the interstate natural gas pipeline system
- **Additional state actions** (including possibly establishing an organization to set standards as NERC does for bulk electric system entities) **to enhance the reliability** of intrastate natural gas pipelines and other intrastate natural gas facilities
- Programs to encourage and provide **compensation opportunities for natural gas infrastructure facility winterization**
- Which entity has authority, and under what circumstances, to take **emergency actions to give critical electric generating units pipeline transportation priority second only to residential heating load**, during cold weather events in which natural gas supply and transportation is limited but demand is high
- Which entity has authority to require certain natural gas-fired generating units to obtain either **firm supply and/or transportation or dual fuel capability**, under what circumstances such requirements would be cost effective, and how such requirements could be structured, including associated compensation mechanisms, whether additional infrastructure build-out would be needed, and the consumer cost impacts of such a build-out
- Expanding/revising natural gas **demand response/interruptible customer programs** to better coordinate the increasing frequency of coinciding electric and natural gas peak load demands and better inform natural gas consumers about real-time pricing
- Methods to streamline the process for, and eliminate barriers to, **identifying, protecting, and prioritizing critical natural gas infrastructure** load
- Whether **resource accreditation requirements** for certain natural gas-fired generating units should factor in the firmness of a generating unit's gas commodity and transportation arrangements and the potential for correlated outages for units served by the same pipeline(s)
- Whether there are **barriers to the use of dual-fuel capability** that could be addressed by changes in state or federal rules or regulations. The forum could also consider the use of other resources which could mitigate the risk of loss of natural gas fuel supply
- **Electric and natural gas industry interdependencies** (communications, contracts, constraints, scheduling)
- Increasing the amount or use of **market-area and behind-the-city-gate natural gas storage**
- Whether or how to **increase the number of "peak-shaver" natural gas-fired generating units** that have on-site liquid natural gas storage

Source: FERC-NERC-Regional Entity Staff Report, The February 2021 Cold Weather Outages in Texas and the South Central United States

Several Runs at Addressing Coordination Issues

- Discussion of gas-power interdependence dates back to the early 2000s, as a gas-fired generation build-out was under way across the United States (see Figure 5.2). However, action on the issue over the past 20 years has been sporadic and limited in scope.
- The NAESB, formed in 2002 as a successor to the Gas Industry Standards Board, is an industry forum for the development and promotion of standards, including standard contracts, for wholesale and retail natural gas and electricity. Issues of operational coordination were almost immediately introduced, with the formation of a NAESB Gas-Electric Coordination Task Force in 2003.
  - Among the proposed standards for development were increased alignment of gas and power day activities, including possibly adding an additional intraday gas nomination cycle to provide more flexibility to shippers to allow generators to nominate more gas to support their power market clearing times, as well as pricing options that would encourage capacity release.
  - Ultimately, NAESB put into place standards to allow for communication of operational information between gas pipelines, electric system operators, and power generators, approved via FERC Order 698.
- NAESB revisited coordination through a Gas-Electric Harmonization Committee formed in early 2012 as the Department of Energy looked at the growing potential for natural gas (post-fracking) and its potential for lower-carbon energy. As with the earlier efforts in the early 2000s, coordination of gas/electric timelines, additional flexibility in scheduling gas transportation, and greater availability of information on gas and power system conditions were noted as areas where standards might be revisited. But NAESB membership could not reach consensus on adoption.
- Despite that, in Order 809 issued in April 2015, FERC moved back by 1.5 hours the deadline for scheduling gas transportation and approved addition of a third intraday gas nomination cycle to adjust scheduling to reflect changes in demand. FERC and NAESB, however, declined to change the nationwide start of the gas day to better align generator needs and gas timelines.

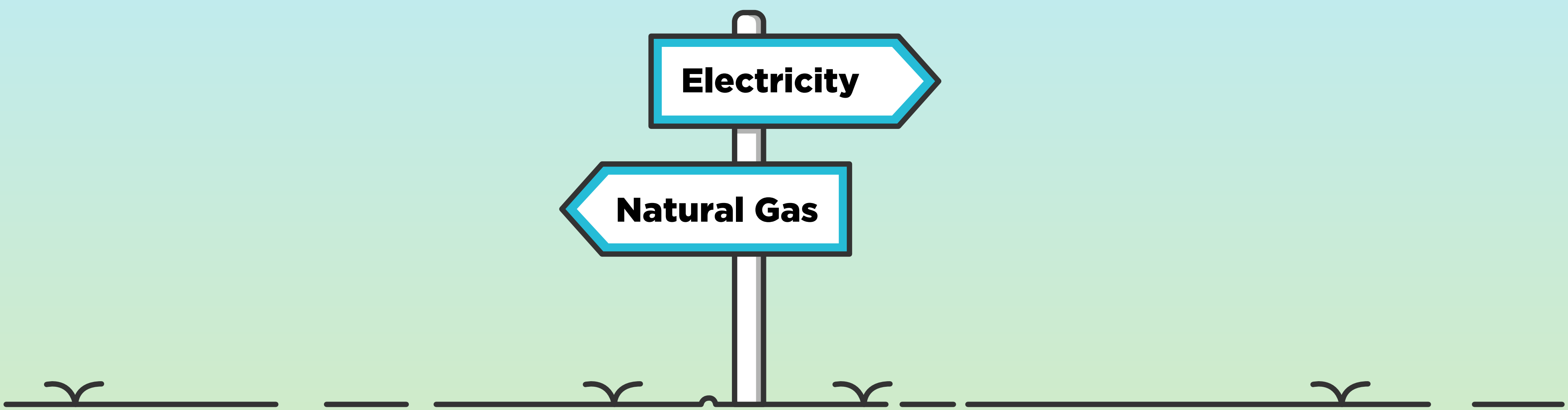


Figure 5.2: **Some Gas-Power Interdependence Issues**

Continued and growing reliance on gas-fired generation

- The power sector is the largest natural gas-consuming sector in the United States.
- Gas-fired generation continues to provide decarbonization benefits (vs. coal) and operating flexibility for balancing and firming renewable resources.

Limited on-site gas storage capability

- While natural gas is storable, storage is not necessarily near power facilities and may not be available at the volumes needed to run a gas-fired power plant for an extended period, forcing reliance on available gas transportation.

Extreme weather and coincident demand

- During cold weather, power generation and residential end-use demand for gas compete, with residential service taking priority and potentially disadvantaging generation.

Gas shipping priorities and incentives

- Because a generator—especially in competitive markets—may not know whether it will be dispatched, it might not procure firm gas transportation, limiting its flexible operation.

Gas capacity expansion impediments

- Generator reluctance to contract firm capacity also affects expansion of pipeline capacity, since long-term firm contracts are needed to approve capacity expansions.
- Despite increasing electric demand for gas and cold snaps causing spikes in demand for gas pipeline capacity, adding such capacity has become a lengthy, expensive, and uncertain proposition due to siting and other objections.

Fuel assurance concerns

- According to NERC, disruptions to the fuel delivery can result from adverse events that may occur, such as line breaks, well freeze-offs, and/or storage facility outages.
- The pipeline system can be impacted by events that occur on the electric system (e.g., loss of electric motor-driven compressors) that are compounded when multiple plants are connected through the same pipeline or storage facility.

Timing of gas and power days

- Because of gas operations needs (pipeline capacity and pressure), gas nominations (requests to move gas from one location to another) are made at a few discrete times each day.
- Power systems may have day-ahead and real-time bids where generators may not know whether they will dispatch and need gas, and hourly power demand may change significantly, requiring more gas than arranged.

Source: ScottMadden analysis

Agreement, Divergence, and a Proposal for a Gas Reliability Organization

- As mentioned earlier, after a year of deliberation, NAESB released its gas-electric harmonization forum report (the NAESB Report) in July 2023. The forum arrived at 20 recommendations voted on by different segments of NAESB membership.
- There were both strong agreement and divergent opinions between gas and power industries on various recommendations. Key areas of agreement and divergence are summarized at Figure 5.3. In particular, upstream gas players disagreed with recommendations on certain information sharing and for state authorities to provide guidelines for weatherization and cold weather preparation.
- The forum co-chairs expressed disappointment in the lack of consensus across the recommendations. In particular, they cited the failure to synchronize the electric and gas markets has led to "consequences [that] continue to linger in the face of the crises that emerged these past two winters" in the forms of Winter Storm Uri (mentioned earlier) and Winter Storm Elliott, in which generator non-performance (including for fuel issues) led to load shedding in late December 2022.
- The co-chairs also characterized gas industry resistance to standardized contractual provisions that would encourage weatherization actions (by limiting force majeure claims in the "absence of taking preventative measures") as "disappointing and unproductive."
- Gas suppliers disagreed with the co-chairs' characterization, pointing to the 80% of recommendations that they supported and their collaboration on addressing the issue of cold weather fuel availability challenges for gas generators.
- Finally, speaking for themselves, the forum co-chairs proposed a structural change, calling for the creation of a natural gas reliability organization akin to NERC, which is responsible for electric reliability. According to the chairs, "balanced solutions discussed in [the forum's] report would find home at an institutional forum empowered to more timely address these and other related matters on an ongoing basis."

Figure 5.3: **Gas Electric Harmonization Forum: Key Areas of Agreement and Divergence**

High Consensus Areas

- Alignment of timelines between the power day and/or the day-ahead scheduling timelines with the gas day
- Adoption of multiday generation unit commitment processes
- State PUC encouragement of gas and electricity demand response programs
- State PUC encouragement of voluntary conservation public service announcements

Areas of Divergence (High Electric/Lower Gas Consensus)

- Revision of business practice standards for timely reporting of gas pipeline informational website posting data
- Using Argonne National Laboratory's NGInsight tool for situational awareness and communications between owners and operators of gas production and processing facilities and electric system operators
- Encouraging state PUCs and authorities with competitive markets to engage with producers, marketers, and intrastate pipelines to ensure 24/7 readiness for forecasted extreme weather
- Encouraging state authorities to establish information posting requirements for intrastate pipelines similar to that required of interstate pipelines
- Encouraging state authorities to consider development of region-appropriate weatherization guidelines

"We simply cannot keep the lights on or heat our buildings if both electricity networks and natural gas production and delivery systems do not operate synchronously."

- Forward from the Chairs, 2023 NAESB Gas Electric Harmonization Forum Report

Source: 2023 NAESB Gas Electric Harmonization Forum Report

What's Next?

- There is no immediate action anticipated in the wake of the NAESB Report. However, gas-power infrastructure interdependencies remains a key risk being monitored by NERC and FERC.
- In its latest reliability risk priorities report, NERC notes that energy subsector (gas/power) interdependence continues to increase and creates the "potential for common-mode failures that could have widespread reliability impacts" and points to gas system weatherization needs, a pace of pipeline development inconsistent with gas demand, and electricity needs for gas pipeline pressurization.
- On September 21, 2023, the final report of the FERC, NERC, and Regional Entity Joint Inquiry into December 2022's Winter Storm Elliott recommended, among other things, reliability rules for natural gas infrastructure that include:
  - Rules including cold weather preparedness plans, freeze protection measures, and operating measures during extreme cold weather periods
  - Situational awareness by establishing regional gas communications coordinators (similar to reliability coordinators for the power grid)
  - Designation of critical natural gas infrastructure loads for protection from load shed
- FERC is scheduled to hold a reliability technical conference in November 2023. While topic areas are broad, one question FERC has posed for discussion is whether it should pursue any specific recommendations coming from the NAESB Report.

Figure 5.4: **Natural Gas Fuel Issues During Winter Storm Elliott**

Natural Gas Infrastructure Reliability Issues During Extreme Cold Weather Led to Fuel Issues During Winter Storm Elliott

Production Infrastructure

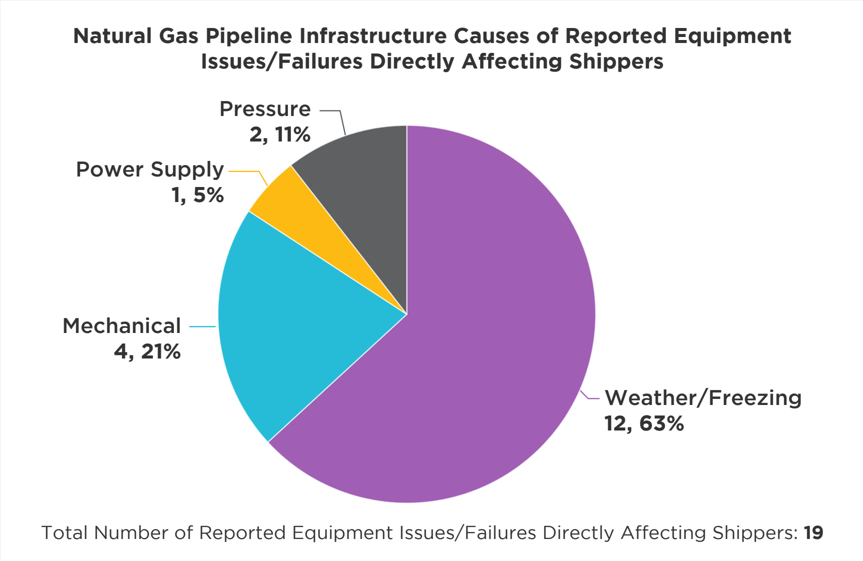
- Wellhead freeze-offs, other equipment freezing
- Poor road conditions due to storm/cold weather, preventing maintenance

Processing Facility Operating Issues

- Reduction in receipt (production) volume
- Producer freeze and pressure issues
- Processing plant disruptions and outages caused by freezing and mechanical issues

Pipeline Infrastructure

- Equipment issues directly affecting shippers (e.g., end-users such as generating units, local gas delivery companies)
  - Weather/freezing issues (majority)
  - Mechanical issues
- Interstate pipelines mitigated other equipment issues to avoid impacts to shippers



There were 63 natural gas-fired unit outages/ derates totaling more than 10 GW due to gas transportation curtailments during WS Elliott.

Source: FERC, NERC, and Regional Entity Joint Staff Inquiry

IMPLICATIONS

With each weather event, especially extreme and extended cold weather, generation and gas infrastructure performance reminds utilities of potential systemic risks to reliability. These issues will grow as more end uses—such as heating and transportation—are electrified. Ironically, the potential reduction of gas heating load (and concomitant increase in power demand) due to electrification could exacerbate gas-power interdependence issues at the wholesale level.

Even without FERC or state action or changes to industry standards, utilities, system operators, and gas industry participants are well served to consider regionally appropriate planning, information sharing, and operational coordination to prepare both power and gas systems for weather events.

Sources:

FERC–NERC–Regional Entity Staff Report, The February 2021 Cold Weather Outages in Texas and the South Central United States (Nov. 2021) (November 2021 Uri Report); NAESB; ICF Resources for U.S. Dept. of Energy, Summary of the North American Energy Standards Board Gas and Electric Interdependency Final Report to the Federal Energy Regulatory Commission in Docket No. RM05-28-000 "NAESB Report on the Efforts of the Gas-Electric Interdependency Committee" (June 22, 2006); NAESB, Gas Electric Harmonization Forum Report (July 28, 2023); FERC Order 698, *Standards for Business Practices for Interstate Natural Gas Pipelines / Standards for Business Practices for Public Utilities* (June 25, 2007); NAESB, Gas-Electric Harmonization Committee Report (Sept. 2012); "FERC Approves Final Rule to Improve Gas-Electric Coordination," FERC Press Release (Apr. 16, 2015); FERC Order 809, *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities* (Apr. 16, 2015); Southwest Power Pool, et al., R23001 Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or Electronic Transaction (May 3, 2023); S&P Global Market Intelligence, "Lack of results from gas-power cooperation forum leaves cochairs frustrated" (Aug. 1, 2023); "NGSA Disappointed in NAESB Gas-Electric Harmonization Forum Report Language," NGSA Press Release (July 31, 2023); NERC, 2023 ERO Reliability Risk Priorities Report (Aug. 17, 2023); FERC, NERC, and Regional Entity Joint Staff Inquiry, December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations (Sept. 21, 2023); FERC Supplemental Notice of Technical Conference, *Reliability Technical Conference*, Docket No. AD23-9-000 (Sept. 22, 2023)

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FERC Homes In on Transmission

The commission issues several new rules—one characterized as a "watershed moment"—with more coming.

FERC Issues Three Significant Orders Addressing Interconnection, Weather Preparedness, and Cybersecurity

- FERC initiated several dockets in 2021 and 2022 to address recurring challenges in the bulk power system.
  - In June 2021, in the wake of Winter Storm Uri—which caused significant adverse effects on the grid in Texas and the surrounding region—FERC held a technical conference to "discuss climate change, extreme weather, and electric system reliability." This was followed in June 2022 with a notice of proposed rulemaking citing seven extreme heat and cold events since 2011 and proposing long-term planning for similar potential events in the future.
  - In April 2022, FERC opened a docket captioned "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection" to address halting progress in transmission development and generator interconnection.
  - Finally, the Infrastructure Investment and Jobs Act of 2021 called out the need for advanced cybersecurity protections for the U.S. power system.

In 2023, the commission has issued four rules related to these inquiries.

Order 2023
Requires all public utilities to adopt generator interconnection procedures that accelerate analysis through a "first-ready, first-served" process and incorporates penalties for developers and providers in certain situations.

Order 896
Directs NERC to develop a new or modified reliability standard to require transmission system planning for extreme heat and cold weather conditions over wide geographical areas.

Order 897
Requires transmission providers to prepare one-time informational reports on their extreme weather planning approaches to understand current and planned policies and practices.

Order 893
Provides incentive-based rate treatment for utilities making certain voluntary cybersecurity investments.

KEY TAKEAWAYS

FERC, as promised, has focused on transmission reform to facilitate modernization of the U.S. grid and enable lower emissions resources to be deployed.

FERC issued three significant rules addressing emerging reliability and resource concerns of generation interconnection backlogs, grid planning for extreme heat and cold, and cybersecurity.

Transmission providers will be busy over the next year working on compliance (or confirming compliance in the case of interconnection) as new rules take effect and planning standards are formed.

A theme across the rules is a focus on state-of-the-art technology, whether for grid modeling, transmission technologies, or advanced cybersecurity capabilities.

Order 2023: Queueing Up

- In late July 2023, FERC issued Order 2023, which reforms the FERC's standard generator interconnection procedures and agreements. The reforms are intended to "address interconnection queue backlogs, improve cost and timing certainty, and prevent undue discrimination for new technologies."
- Motivating the rule was the finding by FERC that interconnection queues were unacceptably long, and the cost and timing of interconnection are increasingly uncertain, especially as some projects under the existing serial first-come, first-served process drop out, requiring restudy.
- FERC Chair Phillips characterized the 1,481-page rule as "a watershed moment for our nation's transmission grid." The key terms of the new rule are summarized in Figures 6.1A-B.

Figure 6.1A: **Key Terms of Order 2023**

First-Ready, First-Served Cluster Process

- All transmission providers must use a single-phase, 150-day cluster study process.
- Process is to be first-ready, first-served—i.e., individual requests submitted during a certain time window are processed together with the same priority.
- Study process follows a 45-day customer request window and a 60-day customer engagement window.

Cost Allocation

- Cluster study costs may be allocated between 10% and 50% on a per-capita basis with remainder (50%-90%) allocated pro rata by MW to cluster members.
- Network upgrade costs are to be allocated based upon "proportional impact" that affects need for the upgrade.
  - One exception: shared substation upgrades, which are to be allocated per capita to all interconnection customers connecting to the substation.
  - Later clusters do not have to fund upgrades in earlier clusters that they might benefit from.

Increased Financial Commitments and Commercial Readiness Requirements

- To prevent speculative interconnection requests, there are increasing financial commitments and readiness requirements through the study process.
- A single deposit is required at the time of request (no multiple deposits) based on MW size of proposed generating facility.
- Ninety percent (90%) site control is required at time of interconnection request, with 100% upon signing of a facilities study agreement.
  - Site control requires demonstration of exclusive rights to develop, construct, operate and maintain a proposed project.
  - "Reasonable evidence of site control" includes documentation of ownership, leasehold interest, an option to purchase or lease a site of "sufficient size" to construct and operate the generator.
  - A deposit ($500K to $2M) in lieu of site control is permissible where regulatory limitations prohibit site control.
- Non-financial readiness demonstrations are not required, only financial deposits at the beginning of each study process: initial cluster study, cluster restudy, and facilities study.
- The required deposit upon execution of a large generator interconnection agreement is 20% of network upgrade costs.

Sources: Order 2023; Troutman Pepper; Foley & Lardner; Bracewell; Midcontinent ISO

Figure 6.1B: **Key Terms of Order 2023**

Transmission Provider Penalties

- Transmission providers who fail to meet study deadlines will be subject to financial penalties; "reasonable efforts" do not mitigate those penalties.
- Penalties amount to $1K to $2.5K per business day, depending upon type of study, up to a cap of 100% of deposits received for all requests in the cluster for studies and restudies.
- Penalties can be avoided if delay is corrected within 10 business days.

Customer Withdrawal Penalties

- Withdrawing interconnection customers may be eligible for refunds of deposits to the extent they exceed study costs incurred.
- However, those amounts are subject to withdrawal penalties that can range from 2X study costs up to 20% of network upgrade costs.
- Withdrawal penalties can only be imposed if it has a "material impact on the cost or timing of any interconnection requests with an equal or lower queue position."

Incentivizing New Technologies

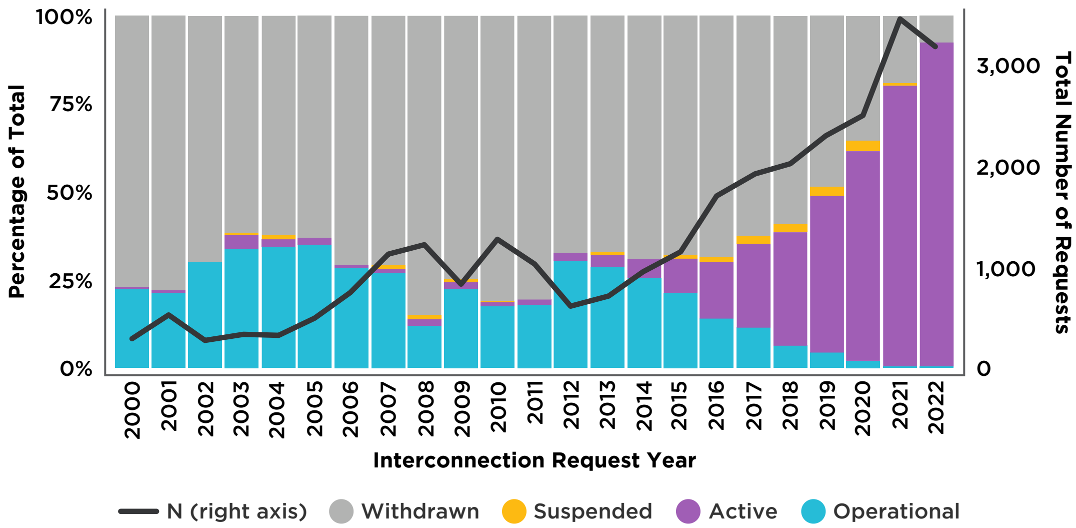
- Providers must allow more than one resource to co-locate on a shared site and share a single interconnection request (e.g., solar + storage).
- Providers must evaluate alternative transmission technologies (from a list of eight technologies designated by FERC).
- Providers must use, upon customer request, operating assumptions that reflect proposed charging behavior for storage resources.

Transparency

- Transmission providers must make publicly available a heatmap of available transmission capacity.
- Providers must coordinate with "affected systems," including studies and possible reimbursement for affected system upgrades.

Sources: Order 2023; Troutman Pepper; Foley & Lardner; Bracewell; Midcontinent ISO

Figure 6.2: **Projects Proposed for Transmission Interconnection (2000-2017) and Their Disposition (as % of Total) of Year-End 2022**

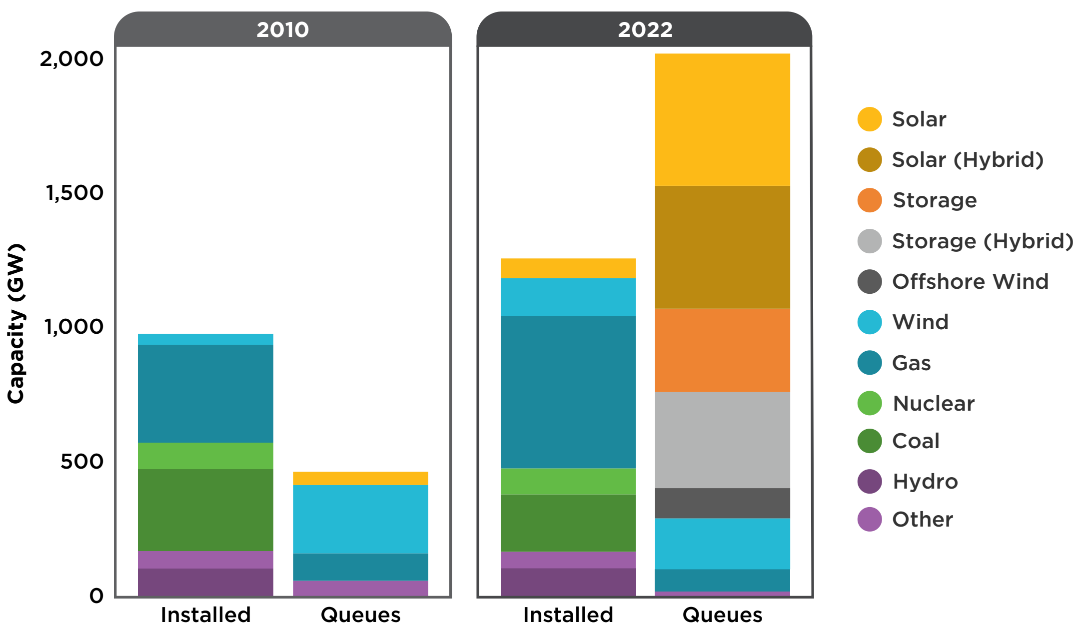


Only 21% of all projects proposed from 2000-2017 had reached commercial operations by the end of 2022—72% had withdrawn from queues.

Note: Limited to data from 7 ISO/RTOs and 26 utilities.

Source: Lawrence Berkeley National Laboratory

Figure 6.3: **U.S. Installed Capacity vs. Capacity in Active Interconnection Queues (Year-End 2010 vs. 2022) (GW)**



- **Active capacity in queues (~2,040 GW) exceeds installed capacity of entire U.S. power plant fleet (~1,250 GW).**
- **Variable resources solar and wind contribute a smaller percentage of their nameplate capacity to resource adequacy compared to dispatchable generation like natural gas.**
- **Decarbonization will thus require higher levels (GW) of solar and wind to achieve same resource adequacy. One can expect that queues will continue to swell with such projects.**

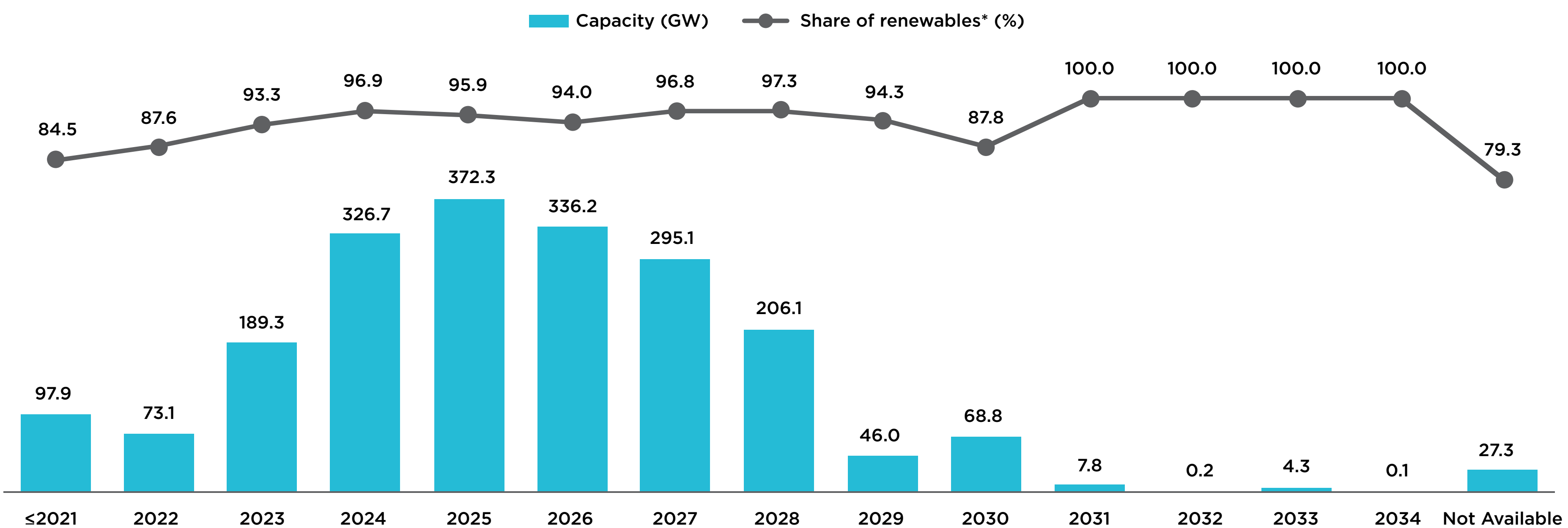
Notes: (a) Hybrid storage in queues is estimated for some projects.
(b) Total installed capacity from EIA-860, December 2022.
(c) RTO installed capacity from FERC Annual State of the Markets Report (https://www.ferc.gov/media/report-2021-state-markets).

Source: Lawrence Berkeley National Laboratory

Order 2023: Comments and Issues

- Cluster studies and some other features of Order 2023 are already being employed in regions such as PJM and the Midcontinent ISO. However, some provisions such as the time marks for study completion will be new and require implementation.
- Some industry players have argued that the elimination of the "reasonable efforts" standard and imposition of penalties for failure to meet deadlines was not supported by the record. Other objections include:
  - The multiprong withdrawal penalty structure for generators is overly complicated.
  - ISOs and RTOs do not have shareholders, so penalties would be passed through to market participants, which would make them indifferent to the penalties.
- Other industries, however, are pleased with the rule. The Solar Energy Industries Association applauded the exclusion of a requirement of having an offtake agreement in place before entering the interconnection queue, which it termed "an impossible standard to meet."
- All transmission utilities must look at their generator interconnection processes considering the new rule and update them as needed and consider a transition approach for existing interconnection requests based upon their position in the study process.

Figure 6.4: **U.S. Interconnection Queue Capacity by Proposed Online Year (GW)**



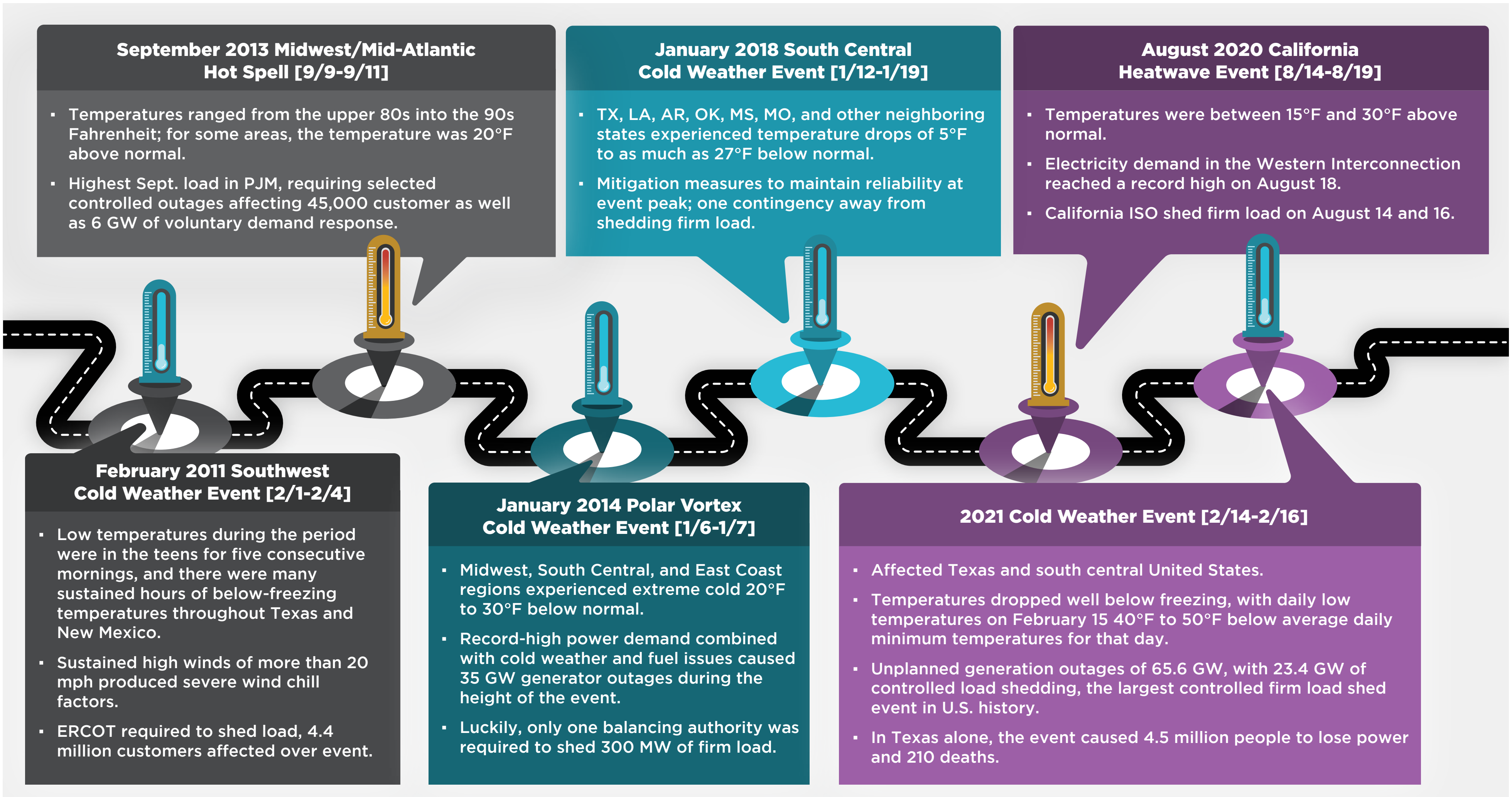
Notes: As of June 28, 2023.
*Selected renewable energy types: battery storage, biofuels, geothermal, solar, wind. Excludes non-specified hybrid. Active queues only. Online years before 2022 may reflect delays sometimes accompanied by adjusted online dates.

Source: S&P Global Market Intelligence (from public company reports)

Preparing the Grid for Extreme Weather: New Standards Mandated

- At the June 2021 extreme weather technical conference mentioned earlier, FERC found that extreme weather events have occurred with greater frequency in recent years (see Figure 6.5) and are projected to occur with even greater frequency in the future. Reliability coordinators have cited extreme weather events as an increasing risk (see Figure 6.6).

Figure 6.5: **Selected Events That Motivated Order 896 Planning Standard Mandate**

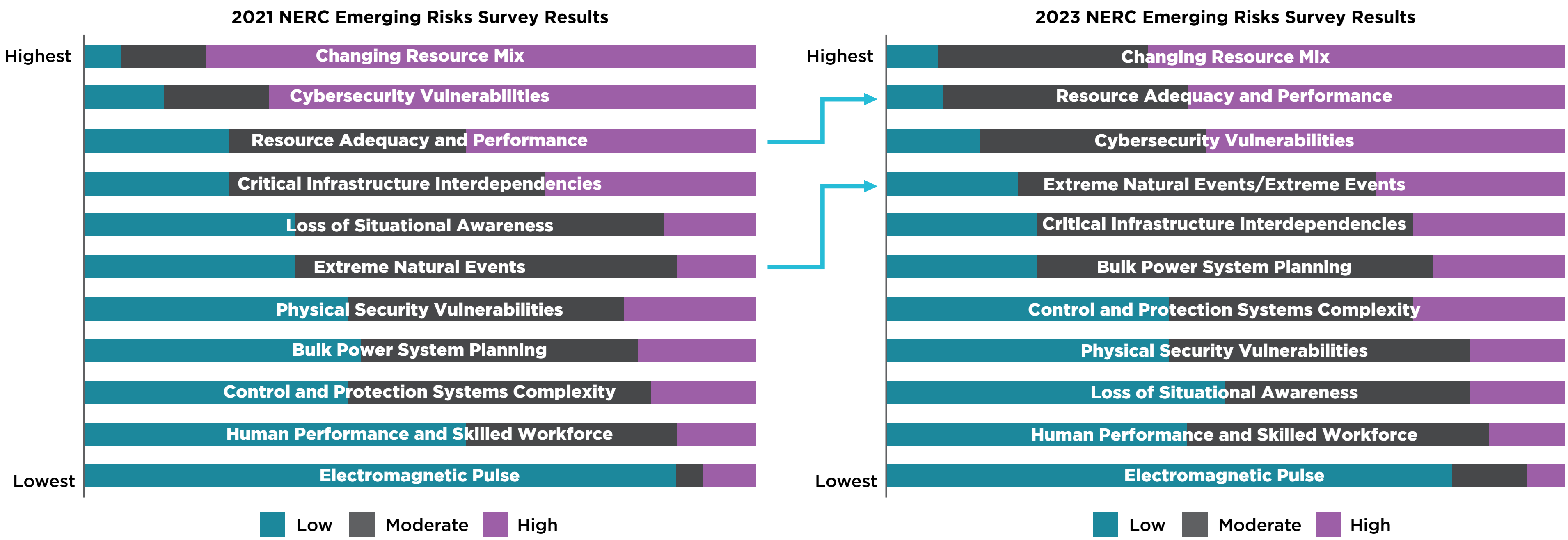


Source: FERC Order 896 Notice of Proposed Rulemaking

Preparing the Grid for Extreme Weather: New Standards Mandated (Cont.)

- FERC also found that planners cannot simply project historical weather patterns forward to effectively forecast the future, since climate change has made those patterns no longer representative of future conditions, and that "transmission planners and planning coordinators must account for this new reality in their planning processes."
- Seeking to improve grid reliability, FERC issued Order 896, which directs NERC to develop a new or modified reliability standard that requires transmission system planning for extreme heat and cold weather conditions over wide geographic areas, including studying impact of concurrent transmission and generation failures. The order also requires corrective action plans when the standard is not met. A summary of key elements of the order is at Figure 6.7.
- This rule builds upon FERC-mandated "Cold Weather Reliability Standards," which require generators to implement cold weather preparedness and freeze protection measures.
- Pursuant to the order, NERC has launched a project to update its current reliability standard, TPL-001-5.1 (transmission system planning performance requirements), which currently does not consider extreme hot/cold weather. Among key activities for drafting a standard will be developing "benchmark events" and planning cases in terms of:
  - Frequency (1-in-50-year event) and probability distribution (95th percentile event)
  - Aligned assumptions between neighboring planning regions
- Order 896 became effective in September 2023, and NERC's compliance filing is due in late December 2024. The updated standard becomes mandatory no more than a year after FERC approves it, although NERC may authorize a phased-in implementation.

Figure 6.6: **Extreme Natural Events Rise in Perceived Reliability Risk**



Source: NERC

Figure 6.7: **FERC Requirements for NERC in Developing an Extreme Weather Planning Standard Under Order 896**

Benchmark Planning Cases

- Planning entities must develop extreme heat and cold (EHC) weather “benchmark events” and “benchmark planning cases” based on identified benchmark events and/or meteorological projections.
- Benchmark events include defined prior EHC weather events.
- NERC can consider other criteria for defining a benchmark event, including use of projected frequency or probability distribution.
- Planning regions likely to be impacted by the same EHC events should use consistent benchmark events.
- Benchmark events should reflect regional differences in climate and weather patterns.

Wide-Area Effects

- Transmission planning studies must consider wide-area impacts of EHC events, and NERC will define a set of contingencies to be considered.
- Criteria for EHC events should include a consideration of wide-area conditions affecting neighboring regions and their impact on a planning area’s ability to rely on the resources of another region during the weather event.
- NERC must describe the process that an entity must use to define the wide-area boundaries, which could be a geographical approach and/or electrical approach.

Responsible Entities and Information Sharing

- Reliability coordinators should not be responsible for developing benchmark planning cases or conducting wide-area studies, as their focus is on real-time operations.
- Designated “responsible entities” for planning should have the planning tools, expertise, processes, and procedures to develop benchmark planning cases and analyze EHC events in the long-term planning horizon.
- NERC may designate an existing functional entity or group of entities or may establish a new entity to conduct these tasks.
- Functional entities will be required to share system information with planning entities, and study results must be shared with affected transmission operators, transmission owners, generator owners, and other functional entities with a reliability need for the studies.

System Planning Studies

- Concurrent/correlated generator and transmission outages and derates during EHC events must be studied.
- Responsible entities perform both steady state and transient stability (dynamic) analyses in the EHC weather planning studies.
  - Steady state analysis: Models system components as either in-service or out-of-service and the result is a single point-in-time snapshot of the system in a state of operating equilibrium
  - Transient stability (dynamic) analysis: Examines the system from the start to the end of a disturbance to determine if the system regains a state of operating equilibrium
- NERC will determine whether and how impacts of demand response are modeled.
- Sensitivity analyses will be required to demonstrate the impact of changes to benchmark planning case assumptions.
- Probabilistic analyses will be required, expanding beyond current deterministic approaches.

Corrective Action Plans

- The planning standard will require development of corrective action plans that mitigate specified instances where performance requirements during EHC weather events are not met, as well as processes to facilitate coordination with regulatory authorities or governing bodies responsible for retail electric service.

Sources: Order 896; Akin Gump Strauss Hauer & Feld; ScottMadden analysis

Understanding Current Approaches to Extreme Weather Vulnerability Assessment

- A tandem rule—Order 897—was promulgated, requiring transmission providers to provide one-time reports on how they currently assess the impacts of extreme weather on their transmission assets and operations, if at all. The report is to assist NERC in standards development and provide shared information on best practices. It will also reveal differences between planning approaches and "extreme weather" considerations among regions.
- FERC does not define "extreme weather" for this report but requires transmission providers to explain how they define that concept as they use it for planning. Providers are required to report how they:
  - Establish a scope
  - Develop inputs
  - Identify vulnerabilities and exposure to extreme weather hazards
  - Estimate the costs of impacts
  - Use the results of vulnerability assessments to develop risk mitigation measure
- The information reports were due October 25, 2023. Figure 6.8 lists 21 specific areas for transmission companies to address in their reports.
- In their concurrence, Commissioners Phillips and Clements encouraged transmission providers to specifically report on how they engage with disadvantaged and vulnerable communities and how they estimate costs of extreme weather as well as mitigation measures for those communities.

Figure 6.8: **Areas to Address in Extreme Weather Vulnerability Assessments Under Order 897**

Overarching
▪ Whether the transmission provider conducts extreme weather vulnerability assessments, and if so, how frequently
Scope
▪ The types of extreme weather events for which the provider conducts extreme weather vulnerability assessments, if any and how the provider determined which extreme weather hazards to include in the assessment ▪ Definitions of an extreme weather event for the purposes of its extreme weather vulnerability assessment, including what thresholds it uses relative to historical measurements or probabilities of occurrence, if applicable ▪ How the provider selects the set of assets and operations that will be examined ▪ How the provider determines the geographic or regional scope of the analysis ▪ Whether and to what extent external interdependencies, such as interconnected utilities, other critical infrastructure sectors (e.g., water, telecommunications), and supply chain-related vulnerabilities, are considered ▪ Whether and to what extent the provider coordinates, or plans to coordinate, with neighboring utilities and/or entities in other relevant sectors ▪ Whether and to what extent stakeholders are engaged in the scoping phase of the assessment
Inputs
▪ Methods and processes the transmission provider uses, or plans to use, to determine the meteorological data needed for its assessment. In particular, how the transmission provider determines whether it can rely on existing extreme weather projections, and if so, whether such projections are adequately robust ▪ How the provider determines whether to use scenario analysis, and if so, whether to do so with multiple scenarios ▪ The extent to which it reviews neighboring transmission providers' extreme weather vulnerability assessments, if available, to evaluate consistency of extreme weather projections. For RTOs/ISOs, a description of how it accounts for differences between transmission owner vulnerability assessment assumptions and results ▪ The time frame(s) and discount rate(s) selected for the extreme weather vulnerability assessment ▪ Methods and processes the transmission provider uses to create an inventory of potentially vulnerable assets and operations
Vulnerabilities and Exposure to Extreme Weather Hazards
▪ How the provider identifies the transmission assets or operations vulnerable to the extreme weather events for which it conducts assessments ▪ How the provider uses screening analyses to test for potential vulnerabilities, as well as how the transmission provider examines the sensitivities of the transmission assets and operations being studied to types and magnitudes of extreme weather events
Costs of Impacts
▪ The methodology or process, if any, the provider uses to estimate the potential costs of extreme weather impacts on identified vulnerable assets and operations ▪ The types of direct and indirect costs used in calculating impacts

Figure 6.8: **Areas to Address in Extreme Weather Vulnerability Assessments Under Order 897 (Cont.)**

Risk Mitigation
▪ How the provider uses assessment results to develop measures to mitigate extreme weather risks, including which risks should be mitigated and time horizon for mitigation and analyses to determine the lowest cost or most impactful portfolio of measures ▪ How the transmission provider informs relevant stakeholders of risks and mitigation measures ▪ Whether and how extreme weather risks and mitigation measures are incorporated into local and regional transmission planning processes ▪ How progress and success of mitigation measures are measured

Note: For purposes of these descriptions, present tense includes current or planned practices.

Source: Order 897, Appendix A

Order 893: A "Carrot" Approach to Advanced Cybersecurity

- The electric industry remains concerned about cyberattacks that threaten the grid. NERC has noted that rapid changes from grid transformation as well as a "changing threat landscape and the convergence of information technology and operational technology, business practices, communication networks, and system resources are increasing the grid's attack surface," resulting in increased cyber and physical security risks.
- The Infrastructure Investment and Jobs Act of 2021 (IIJA) cited the need for advanced cybersecurity, providing both funding ($1 billion) through DOE's cybersecurity office and amending the Federal Power Act to direct FERC to provide a framework for incentive-based rate treatments for utilities' investments in advanced cybersecurity technologies and participation in cybersecurity threat information-sharing programs.
- In April 2023, as directed by the IIJA, FERC released Order 893, which provides a "carrot" in the form of incentives for proactive investment in Advanced Cybersecurity Technology (as defined in the order). This order augments FERC's traditional "stick" approach, which focuses on compliance with NERC's Critical Infrastructure Protection (or CIP) standards. The order, which took effect 60 days after its issuance, is summarized at Figure 6.9.
- Commissioner Danly dissented in the rulemaking, contending it did not do enough to promote cybersecurity investment, pointing to the following:
  - The rule limits incentives to entities with cost-based tariffs only and not utilities that sell power at market-based rates.
  - The rule requires that investments "materially improve" cybersecurity which the IIJA has no such requirement.
  - The final rule eliminates a more generous 200-basis-point ROE adder proposed in the original notice of proposed rulemaking.
  - The rule does not address performance-based ratemaking treatments that Commissioner Danly contends are required by the IIJA mandate.
- FERC's case-by-case consideration of applicable investments and incentive awards will be watched by utilities for signals of preferred investments.

Figure 6.9: **Key Provisions of Order 893**

Eligible Utilities
▪ Both public and non-public utilities and ▪ Have or will have a cost-of-service FERC-approved rate
Eligible Investment Types
▪ "Materially improve" cybersecurity through investment in an Advanced Cybersecurity Technology (defined) or participation in a cybersecurity threat information-sharing program, such as E-ISAC's* Cybersecurity Risk Information Sharing Program (CRISP) and ▪ Are voluntary, that is: - Not mandated by CIP reliability standards or local, state, or federal law - Not the result of action taken in response to a federal or state agency merger condition or consent decree - Not pursuant to a settlement agreement between a utility and a private or public party
Advanced Cybersecurity Technology (Defined)
▪ "Any technology, operational capability, or service, including computer hardware, software, or a related asset, that enhances the security posture of public utilities through improvements in the ability to protect against, detect, respond to, or recover from a cybersecurity threat (as defined in section 102 of the Cybersecurity Act of 2015)" (Order 893, p. 135)
Determination of Specific Eligible Investments
▪ Investments from FERC list (that may be updated) of prequalified (or PQ) expenditures have a rebuttable presumption of eligibility (note: FERC's initial PQ list includes expenditures under CRISP and investments associated with internal network security monitoring) ▪ Investments "tailored to [utilities'] specific situations" subject to FERC approval on a case-by-case basis ▪ Investments to achieve early compliance with a NERC CIP mandatory reliability standard but are not yet enforceable (note: eligibility ends when standards become enforceable)
Incentive Offered: Regulatory Asset Treatment
▪ Eligible expenses include O&M expenses, labor costs, implementation costs, network monitoring, training costs, and SaaS expenses ▪ In lieu of expensing eligible cybersecurity investments as incurred, treatment of expenses as a regulatory asset ▪ Deferred cost recovery of investment, allowing costs into rate base with allowed return on unamortized portion ▪ Amortization of regulatory asset over period up to five years
Reporting
▪ Utilities seeking the Cybersecurity Regulatory Asset Incentive must make a Federal Power Act Section 205 filing, with attestation of the nature of the investment ▪ Generally, upon grant of an incentive, utilities must file an annual information report by June 1 for the duration of the incentive

Note: *E-ISAC is Electricity Information Sharing and Analysis Center operated by NERC.

Sources: Order 893; Morgan Lewis; Davis Wright Tremaine; Akin Gump Strauss Hauer & Feld; ScottMadden analysis

IMPLICATIONS

For some RTOs and utilities, the impacts of Order 2023 may confirm existing practices such as cluster studies. However, the broad approach to timelines and penalties proposed by FERC will require greater specificity and clarity as they are converted to processes and policies.

For extreme hot and cold weather planning, developing scenarios, moving from deterministic to probabilistic approaches, and identifying effects on and from adjacent regions and infrastructure (e.g., gas, water) could require significant changes in analytical approaches and existing models.

Finally, successful system planners, information and operational technology cybersecurity groups, and regulatory departments will need to collaborate to identify advanced cyber technology opportunities and whether identified technologies will benefit from FERC's incentives under Order 893.

FERC is not done yet. It is considering longstanding issues of long-term (20 years) transmission planning and cost allocation (Docket No. RM21-17), which portends additional significant transmission policy changes ahead. After physical attacks on grid infrastructure in NC, WA, and OR, FERC is also considering updating physical security requirements established in Order 802 (issued circa 2014).

The elephant in the room remains permitting reform for infrastructure siting, and Congress has several bills under consideration. But movement on those proposals is halting.

Sources:

FERC Order 2023, *Improvements to Generator Interconnection Procedures and Agreements*, Docket No. RM22-14-000 (July 28, 2023); FERC Order 896, *Transmission System Planning Performance Requirements for Extreme Weather*, Docket RM22-10-000 (June 15, 2023); FERC Order 897, *One-Time Informational Reports on Extreme Weather Vulnerability Assessments Climate Change, Extreme Weather, and Electric System Reliability*, Docket Nos. RM22-16-000, AD21-13-000 (June 15, 2023); FERC Order 893, *Incentives for Advanced Cybersecurity Investment*, Docket No. RM22-19-000 (Apr. 21, 2023); FERC Notice of Proposed Rulemaking, *Transmission System Planning Performance Requirements for Extreme Weather*, Docket No. RM22-10-000 (June 16, 2022); Docket No. AD21-13-000, at https://www.ferc.gov/news-events/events/technical-conference-discuss-climate-change-extreme-weather-electric-system; https://ferc.gov/explainer-transmission-notice-proposed-rulemaking; FERC Staff Presentation, Improvements to Generator Interconnection Procedures and Agreements (July 27, 2023); FERC New Release, "FERC Transmission Reform Paves Way for Adding New Energy Resources to Grid," at https://www.ferc.gov/news-events/news/ferc-transmission-reform-paves-way-adding-new-energy-resources-grid; Foley & Lardner, "FERC's Generation Interconnection Reform Order No. 2023" (Aug. 25, 2023); "Industry Groups Tussle over Penalties, Seek Changes to Interconnection Rule," *Megawatt Daily* (Aug. 31, 2023); "NYISO Seeks Rehearing, Clarification on Parts of FERC Order 2023," *Megawatt Daily* (Sept. 1, 2023); "FERC Approves 'Historic' Rule to Clear Backlog of US Generation Projects," *Megawatt Daily* (July 27, 2023); Akin Gump, "FERC Acts to Bolster Electric Grid Reliability During Extreme Weather Events" (Aug. 14, 2023); NERC, Standard Authorization Request – Transmission System Planning Performance Requirements for Extreme Weather (July 5, 2023); FERC Staff Presentation, One-Time Reports on Extreme Weather Vulnerability Assessments (June 15, 2023); NERC, Cyber-Informed Transmission Planning (May 2023); DOE Office of Cybersecurity, Energy Security, and Emergency Response; Morgan Lewis, "Bipartisan Infrastructure Bill Could Revolutionize the Energy Industry" (Nov. 15, 2021); Lawrence Berkeley National Laboratory; S&P Global Market Intelligence; ScottMadden research

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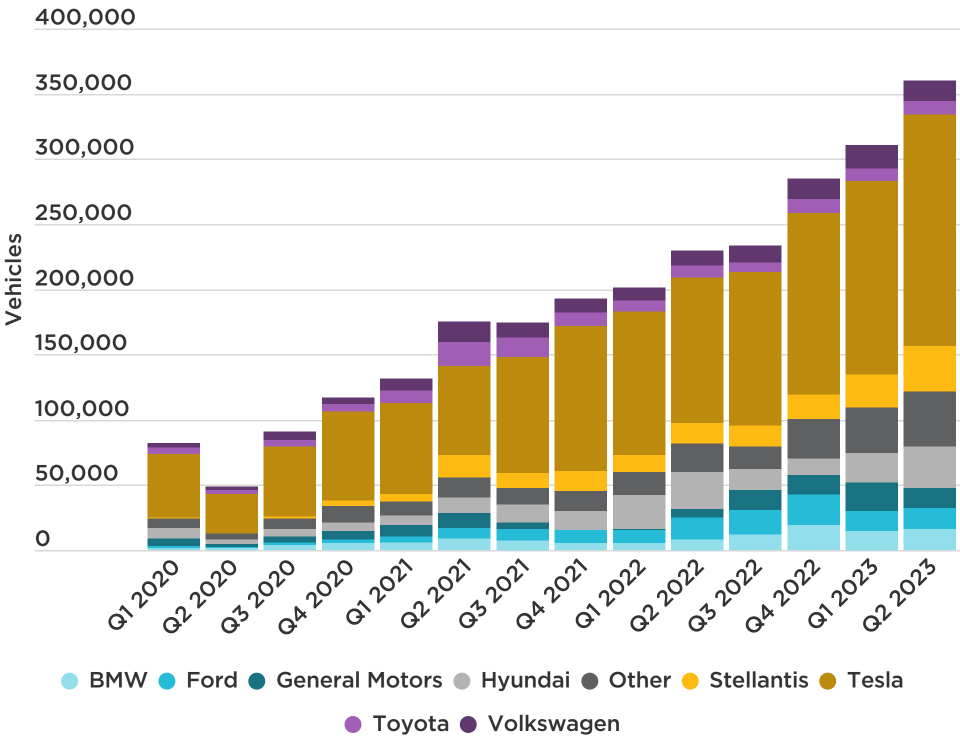
THE ENERGY INDUSTRY
IN CHARTS

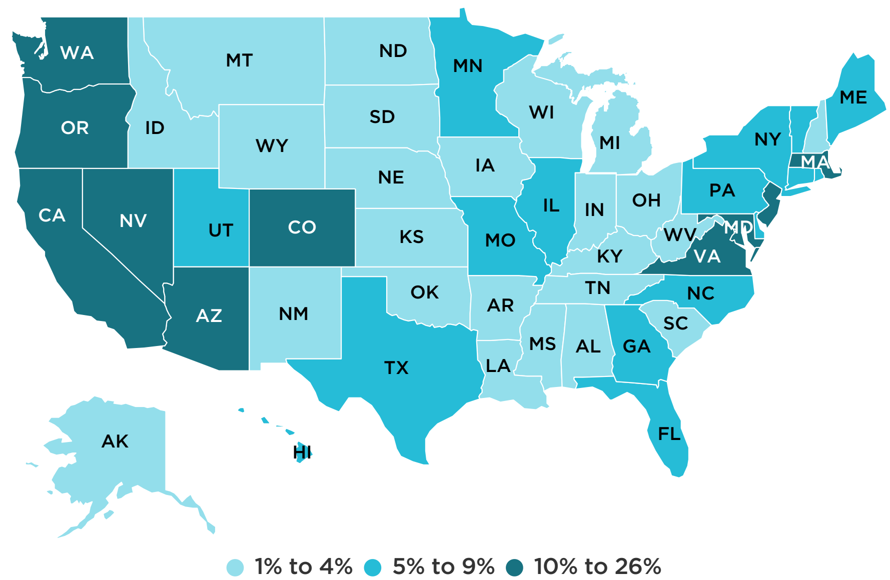
Figure 7.1: **U.S. Quarterly EV Sales by Parent Company (Q1 2020 - Q2 2023)**



Source: Altas EV Hub, Automakers Dashboard

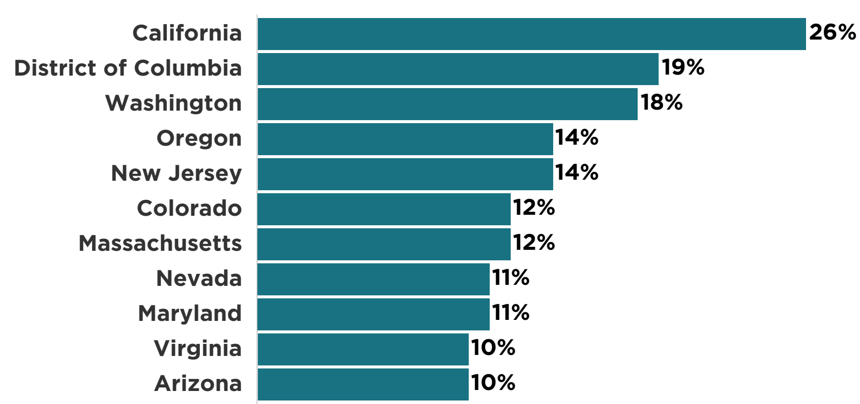
- **With EV sales continuing to grow, the United States is expected to sell more than one million EVs in 2023.**
- **Tesla remains the dominant brand, accounting for nealry half of all EVs sold through 1H 2023.**
- **However, EV adopation varies dramatically by geography.**

Figure 7.2A: **EV Market Share of New Vehicle Sales by State (Q2 2023)**



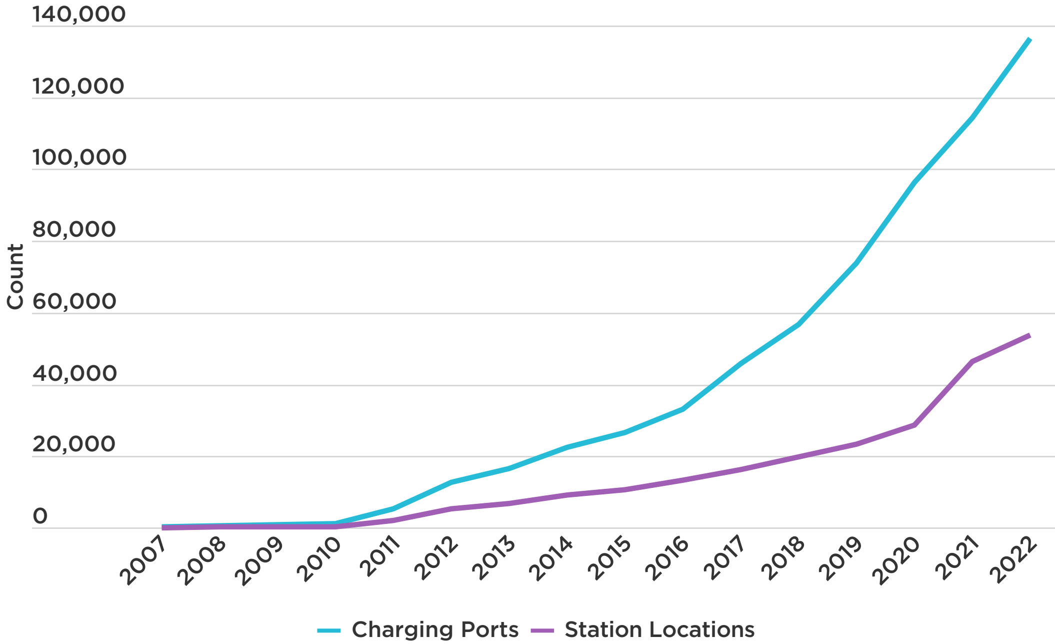
Source: Altas EV Hub, Automakers Dashboard

Figure 7.2B: **States Over 10% EV Market Share of New Vehicle Sales (Q2 2023)**



Source: Altas EV Hub, Automakers Dashboard

Figure 7.3: **U.S. Public Electric Vehicle Charging Infrastructure (No. of Chargiing Ports and Station Locations)**

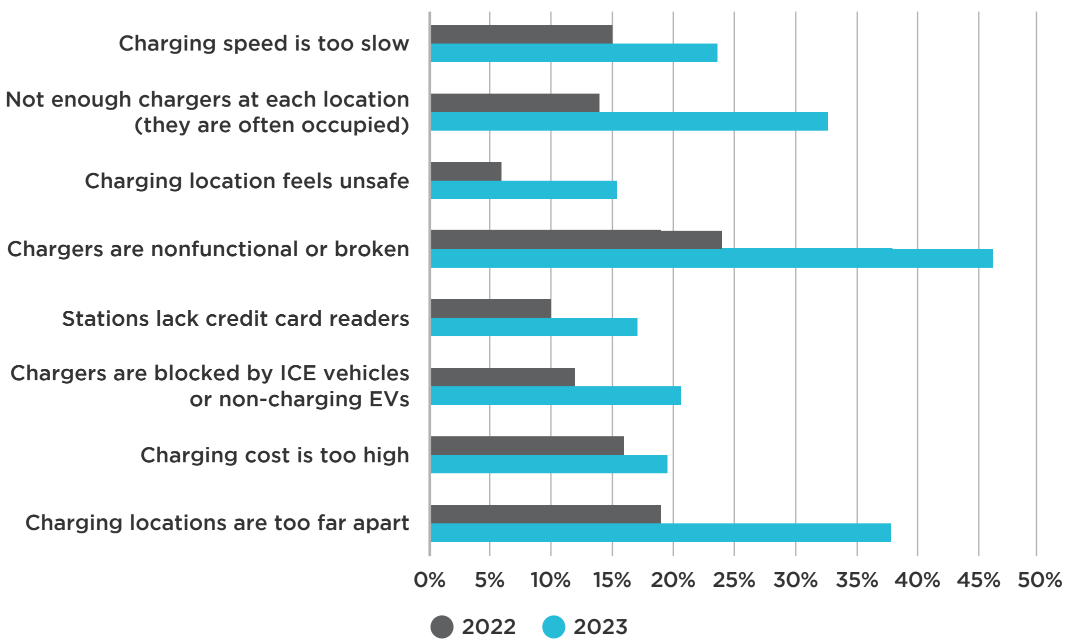


Notes: Data snapshots were taken each year in December, as close to the end of the year as possible.

Between 2007 and 2013, the electric vehicle charging station counts are an estimate of the number of geographic locations (i.e., station locations) based on the number of charging ports, because station counts were not captured in these years. Charging port counts include available legacy, Level 1, Level 2, and DC-fast charging ports through 2021. Beginning in 2022, charging port counts include both available and temporarily unavailable legacy, Level 1, Level 2, and DC fast-charging ports.

Source: Alternative Fuels Data Center

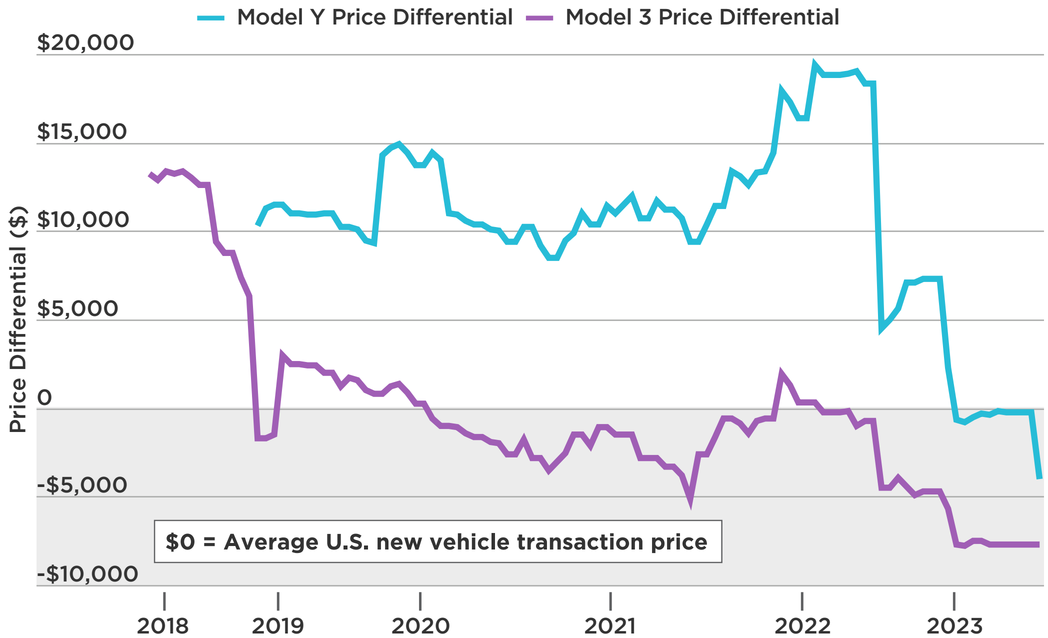
Figure 7.4: **Non-Tesla Public DC Fast-Charging Networks Change in Satisfaction**



Source: Plug In America

- **Drivers have access to a growing number of public charging ports and station locations across the United States.**
- **However, customers report myriad challenges when attempting to use non-Telsa DCFC charging stations.**
- **In 2023, nonfunctional or broken chargers was the most cited customer complaint, followed by charging locations being too far apart.**

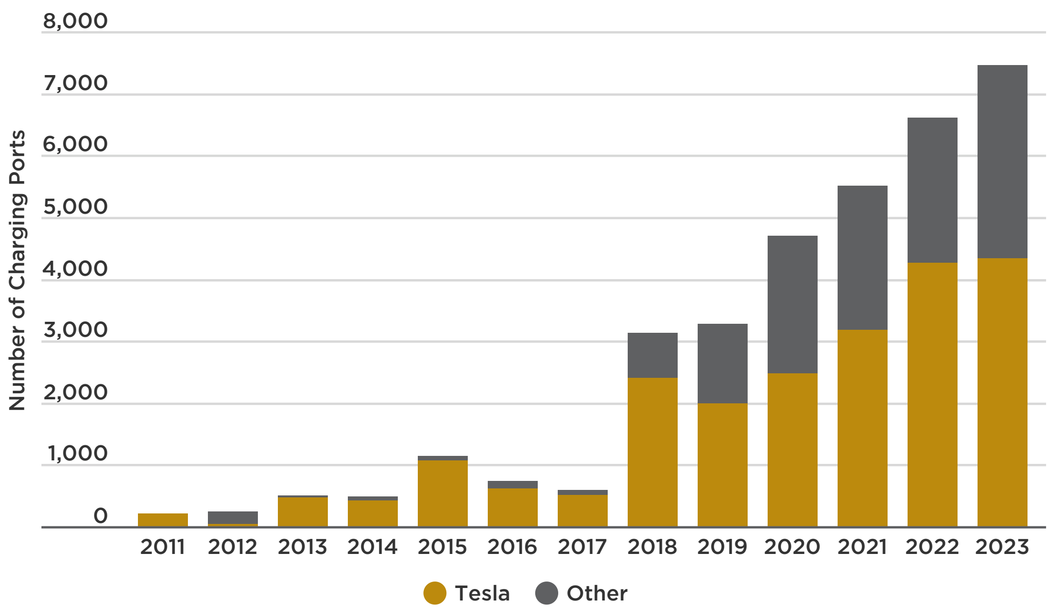
Figure 7.5: **Tesla Model Y and Model 3 Price Differential vs. U.S. Benchmark Transaction Price (in $)**



Note: Differential shows the price of each Tesla base model minus the average transaction price for a new vehicle in the United States for the prior month.

Sources: Bloomberg Green; Tesla; Edmunds

Figure 7.6: **DC Fast Charger Additions by Year (2011-2023)**



Source: Alternative Fuels Data Center

- **Tesla is currently offering the Model Y and Model 3 at prices (before tax credits) less than the average price of a new vehicle.**
- **According to Cox Automotive, the Model Y is the top-selling SUV and the Model 3 is the second best-selling passenger vehicle year-to-date through Q3.**
- **Tesla also accounts for more than 60% of the DC fast-charging ports installed in the United States.**

GLOSSARY

ACE Rule
Affordable Clean Energy Rule

Ass'n
Association

B
billion

BkWh
billion kilowatt-hours

BPU
New Jersey Board of Public Utilities

BSER
best system of emissions reduction

CAA
Clean Air Act

CAISO
California ISO

CCS
carbon capture and sequestration

CO_2
carbon dioxide

Comm'n
Commission

CPP
Clean Power Plan

CT
combustion turbine

DER
distributed energy resources

DKK
Danish krone

DOE
U.S. Department of Energy

EEI
Edison Electric Institute

EHC
extreme hot and cold

EIA
U.S. Energy Information Administration

EPA
U.S. Environmental Protection Agency

ERCOT
Electric Reliability Council of Texas

EV
electric vehicle

FERC
Federal Energy Regulatory Commission

GHG
greenhouse gas

GW
gigawatt

GWh
gigawatt-hour

IIJA
Infrastructure Investment and Jobs Act

IOU
investor-owned utility

IRA
Inflation Reduction Act of 2022

ISO
independent system operator

ISO-NE
ISO New England

IT
information technology

K
thousand

kg
kilogram

kWh
kilowatt-hour

lb.
pound(s)

LDC
local gas distribution company

M or mil.
million

MISO
Midcontinent Independent System Operator

MMBtu
million British thermal units

MW
megawatt

MWh
megawatt-hour

NAESB
North American Energy Standards Board

NERC
North American Electric Reliability Corporation

NYISO
New York ISO

O&M
operating and maintenance expense

PJM
PJM Interconnection LLC

PSC
public service commission

PtX
Power-to-X

PUC
public utility commission

PV
photovoltaic

RNG
renewable natural gas

ROE
return on equity

RTO
regional transmission organization

SEPA
Smart Electric Power Alliance

SNG
synthetic natural gas

SPP
Southwest Power Pool

T&D
transmission and distribution

TBTU
trillion British thermal units

therm
a unit of heat equal to 100,000 British thermal units

TWh
terawatt-hours

USD
U.S. dollars

VPP
virtual power plant

ENERGY PRACTICE
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