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MANAGEMENT CONSULTANTS

ENERGY INDUSTRY UPDATE

THE DISTANCE

Volume 24 - Issue 2

CONTENTS

EXECUTIVE SUMMARY
The Distance

The energy transition remains much discussed in the energy and utilities industry. For some, this transition is not moving at the pace and linearity they would prefer. But some ambitions are meeting the reality of the time and cost of making dramatic changes to an energy system.

The theme of this issue is "The Distance," which reflects time and effort (i) to get new non-emitting energy technologies to commercialization (long-duration storage, next-generation geothermal), (ii) to improve regional transmission planning and get transmission projects under way (FERC orders), (iii) to reconfigure (if feasible) power generation or to preserve resources as long as possible for reliability (EPA greenhouse gas regulations), and (iv) to implement effective programs for affordability (low-income energy affordability).

Below we preview the sections in this edition of the Energy Industry Update.

Some Highlights of This ScottMadden Energy Industry Update	
EPA Greenhouse Gas Emissions Rules for Power Generators	Citing its authority under §111 of the Clean Air Act, the Environmental Protection Agency promulgated new emissions standards for existing fossil steam generators and new gas combustion turbine units. The performance standard—90% carbon capture and storage—is controversial, as many in the industry do not believe the technology is well proven. Continuing litigation will determine whether, how, and when the rules are implemented.
FERC Regulatory Developments	Growing levels of renewable resources, more frequent, widespread extreme weather events, and growing energy demand are generating the need for increasing investment in electric transmission. FERC has prioritized transmission development to address this perceived gap. With the issuance of Orders 1920 and 1977 in spring 2024, FERC hopes that a longer-term view of regional and interregional needs and improvements in siting will bolster transmission buildout.
Long-Duration Energy Storage	Electric energy storage is the “holy grail” of a decarbonized electric system. Many current storage installations have used lithium-ion battery technology that has, on a unit basis, four hours or less of duration. With longer-lived disruptions due to extreme weather and to help “firm up” variable, weather-dependent resources, longer-duration storage solutions are necessary. Many firms are researching new technologies to extend the discharge life of storage solutions from intraday to multiday durations.
Low-Income Energy Affordability	The issue of energy and specifically electricity affordability continues to have currency among both utilities and regulators. Contemporaneously, utility investments in aging infrastructure and in decarbonizing energy systems is leading to increased cost pressures. Low-income affordability is a focus area for policymakers, and states are testing approaches to satisfy policy goals such as electrification without placing undue burden on those customers.

EPA Issues Power Plant Greenhouse Gas Rule

The EPA finalizes a rule with major implications for existing coal-fired generation and new gas-fired units.

KEY TAKEAWAYS

EPA has promulgated a suite of rules, including requiring an effective ~90% reduction in GHG emissions from existing coal-fired generators and new gas-fired combustion turbines.

The rule affects 169 GW of coal generation, which is about 14% of the nation's generating capacity.

EPA did not speak to existing gas-fired generation, although operating gas CTs and CCs total about 418 GW.

Absent increased capacity additions, system operators are sounding the alarm.

The rule is being vigorously challenged; it is unclear whether its validity will be impaired by the Supreme Court's "major questions" doctrine.

EPA Modifies and Finalizes Greenhouse Gas Rule

In May 2023, EPA proposed a greenhouse gas (GHG) rule for fossil-fired power plants.

- Motivating the proposal is the Biden administration's "all-of-government" approach to climate policy.
- The proposed rule covered both new and existing fossil-fired generation: coal, oil, and gas. It set GHG emissions standards with time and levels differentiated by unit fuel type and capacity, new or existing unit, planned retirement date, and duty cycle (capacity factor).
- The proposed rule set a performance standard—based upon a "best system of emissions reduction" (BSER)—to be the equivalent of 90% carbon capture and storage (CCS) or low-GHG hydrogen cofiring of 96% upon full implementation of the rule.

EPA promulgated in April 2024 its new source performance standards. The final rule is narrower than the proposed rule and leaves out the largest generation subsector—existing gas-fired combustion turbines (CTs)—to more "comprehensive" rulemaking in 2025 or later.

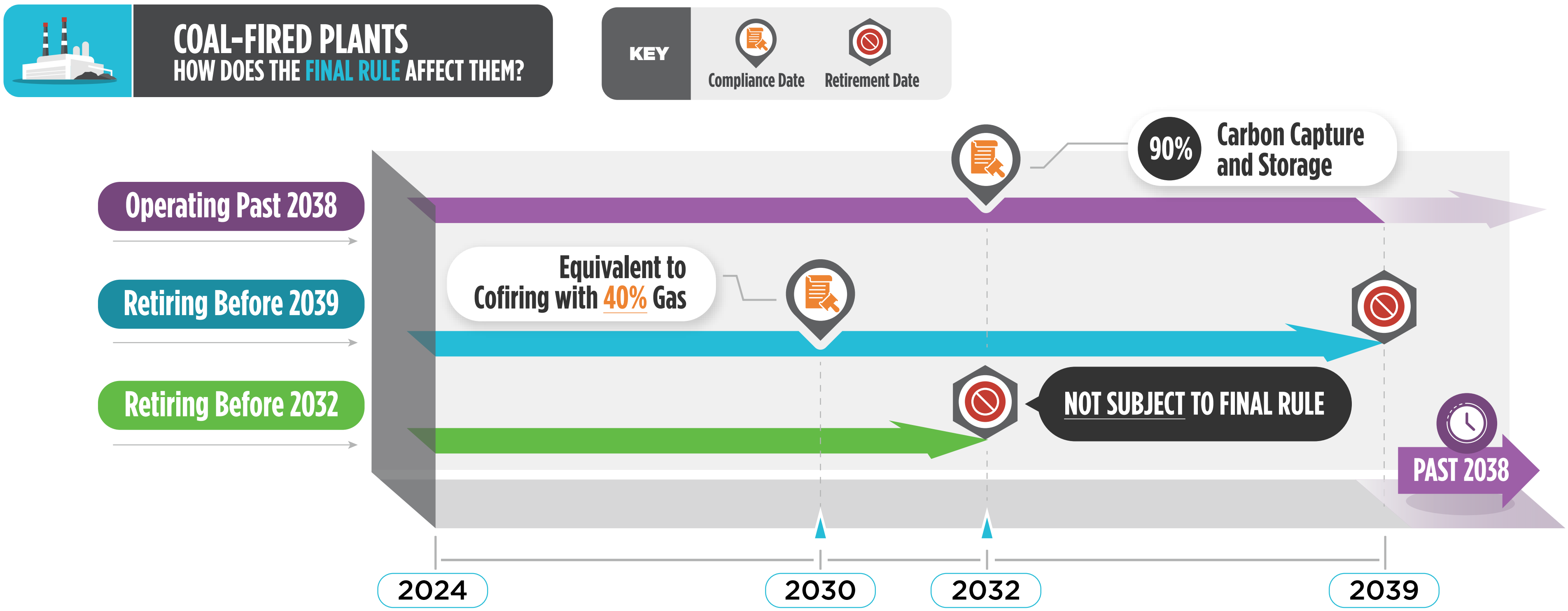
- The rule applies to new or reconstructed fossil-fired CTs, existing fossil-fired steam units, and modified coal-fired steam units (modifications causing >10% in hourly CO_2 emissions).
- EPA has removed low-GHG hydrogen from its BSER, targeting the GHG emissions based upon CCS at a 90% capture rate (equivalent to an 88.4% CO_2 reduction).
- The standard of performance is technology neutral. Although the standards are set by a BSER, sources may comply using other methods—for example, hydrogen cofiring.
- Baseload units have the most onerous emissions standards, and EPA has reduced the threshold operation for a baseload unit at a 40% capacity factor (versus 50% in the proposed rule).

Existing Coal Steam Units: Remaining Life Distinction

The rule takes aim at coal-fired units in particular, mandating compliance by 2032.

- Those coal units deemed long term—i.e., operating past 2031—must meet an emissions threshold by 2023 based upon the 90% capture BSER described earlier.
- Those deemed medium term—i.e., operating past 2031 but committed to retiring before 2039—have an emissions target of the equivalent of cofiring (by heat input) 40% natural gas and a 16% reduction in emissions rate by 2030.
- Those units retiring by 2032 are exempt from the rule.

Figure 1.1: **EPA GHG Emissions Rule: Existing Coal-Fired Steam Units**



Sources: EPA; ScottMadden analysis

Existing Oil- and Gas-Fired Steam Units: Unit Duty Distinction

Existing oil- and gas-fired steam generators can employ “routine methods of operation and maintenance” with no increase in emissions rate as of 2030.

- **Baseload units (oil and gas)—**annual capacity factor >45%—can employ “routine methods” but must be less than 1,400 lbs. CO_2/MWh-gross by 2030.
- **Intermediate load units (oil and gas)—**annual capacity factor ≥8% and ≤45%—have a slightly higher compliance threshold of 1,600 lbs. CO_2/MWh-gross by 2030.
- **Low load units—**annual capacity factor <8%—require only the use of uniform fuels and have emissions limits, based upon heat input, of 130 lbs. CO_2/MMBtu (for gas) and 170 lbs. CO_2/MMBtu (for oil).

EPA determined that CCS as a BSER would capture relatively little CO_2 in comparison to its capital and operating cost. It also noted there are relatively few units (200 gas-fired steam units and 30 oil-fired steam units) that mostly operate as load-following with relatively low capacity factors. Average annual cap factors for gas steam units were less than 15%, and no oil units operated above 8%.

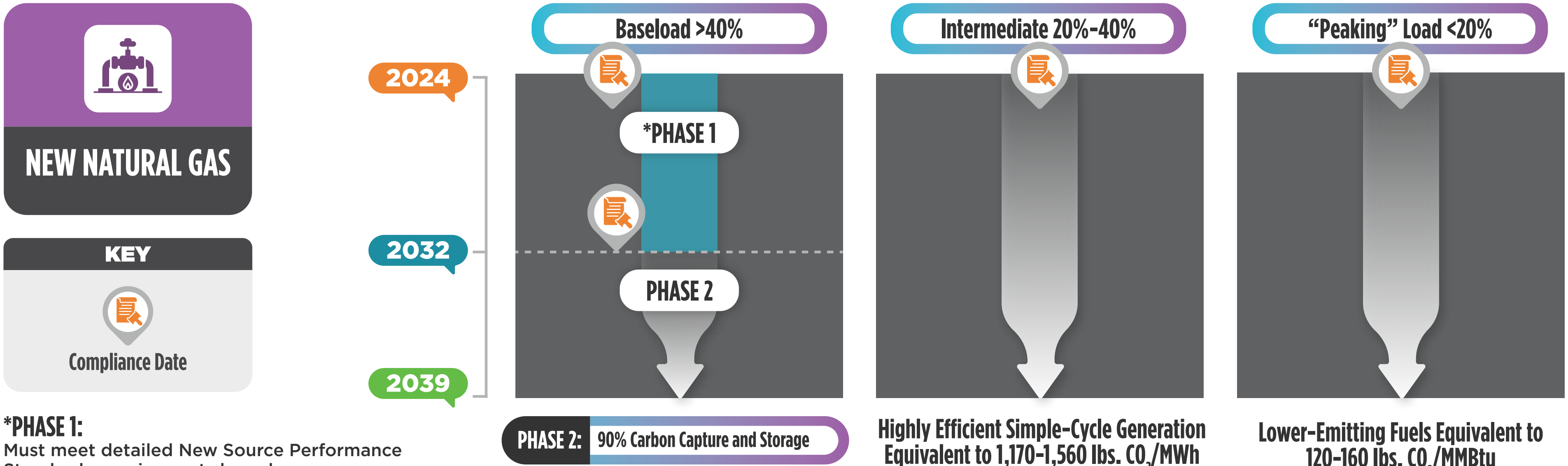
New Combustion Turbines: 90% Carbon Capture BSER for Baseload Units

EPA has established emissions standards for any new CTs operating after May 23, 2023, the date of the proposed rules.

- **Baseload units—**annual capacity factor >40%—must operate at emissions levels equivalent to highly efficient combined-cycle generation (800-900 lbs. CO_2/MWh, depending upon size) until 2032. Thereafter, new CTs must meet a 90% CCS standard effective 2032 or less than 100 lbs. CO_2/MWh.
- **Intermediate load units—**annual capacity factor 20%-40%—must operate at emissions levels equivalent to highly efficient simple-cycle generation (1,170 lbs. CO_2/MWh) upon start-up. There is no future, more stringent Phase II requirement.
- **Low load units—**annual capacity factor <20%—must use lower-emitting fuels and achieve emissions less than 160 lbs. CO_2/MWh upon start-up. There is no future, more stringent Phase II requirement.

For new CTs, EPA's final rule is more stringent than the proposed rule, as EPA lowered the threshold for "baseload" treatment, requiring much lower emissions, to >40% capacity factor from >50% as originally proposed.

Figure 1.2: **EPA GHG Emissions Rule: New Fossil-Fired Combustion Turbines**



***PHASE 1:**
Must meet detailed New Source Performance Standards requirements based on "high-efficiency" combined-cycle combustion technology available immediately upon start-up and then install CCS by January 1, 2032.

Note: Targets referenced in text are for natural gas, which dominates new additions, but the standard noted in the ranges in Fig. 2.1 includes all fossil fuels, including oil.

Sources: EPA; ScottMadden analysis

No Action on Existing Gas-Fired Combustion Turbines

While the new GHG rules cover gas-fired steam units, they do not encompass existing gas-fired combustion turbines. However, EPA stated it is committed to “expeditiously proposing” GHG emission limits for these units. EPA Administrator Regan initiated in March 2024 a non-regulatory docket, with the goal of gathering input for a “stronger, more durable approach to greenhouse gas regulation of the entire fleet of existing gas combustion turbines.”

Timing of Implementation

The final rule changed the compliance timeline from its originally proposed rule in different ways for existing steam units and CTs:

- For new CTs, EPA moved up final compliance from 2035 to 2032 for baseload units.
- By contrast, for existing coal steam units, the compliance deadline was extended to 2032 from 2030.

Under either deadline, it is uncertain whether units can comply with a 90% CCS standard absent significant commercialization of the technology (see Figures 1.3 and 1.4) and deployment of takeaway CO_2 pipeline capacity or nearby sequestration options, which are location specific.

Whither Hydrogen Cofiring?

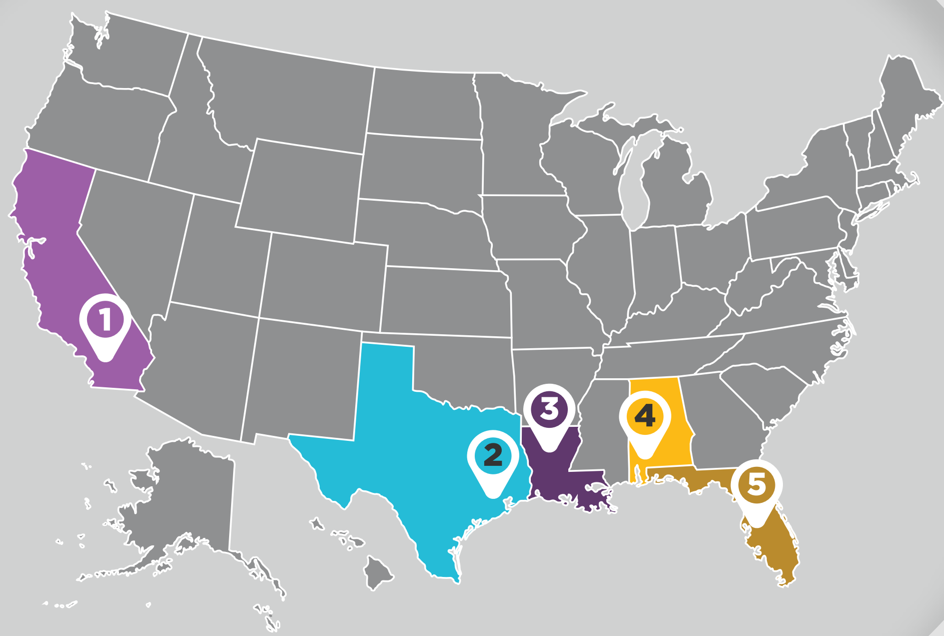
EPA’s proposed 2023 rule proposed an additional BSER pathway for new CTs: low-GHG hydrogen cofiring of 96% (for units with capacity factors of ≥50%) or 30% (for units with capacity factors <50% and ≥20%). EPA eliminated this option in its final rule.

- Many critics of the proposed rule contended that clean hydrogen was not adequately demonstrated and that its cost as a compliance method was underestimated.
- DOE has subsequently studied clean hydrogen “pathways to commercial liftoff” and found that low-emissions hydrogen would be $1.15 per kilogram (equivalent to about $8.50/MMBtu of natural gas), compared to EPA’s assumed $0.50 per kilogram.
- Moreover, the U.S. National Clean Hydrogen Strategy does not envision nearly the volumes required under the proposed rule by the compliance deadline.

This feasibility and cost challenge may be an approach that opponents of the final rule employ.

Figure 1.3: **Selected Operating and Planned U.S. Power Plants with CCS**

There is only **one operational, commercial power generation CCS project** in the United States (Petra Nova), and it captured only **7% of emissions** at the time its operations were suspended in 2020. Approximately 14 other U.S. projects are being evaluated but are in early phases of engineering and design.



1 CalCapture

- **Advanced Development**
- **Expected Operation: 2027**

California Resources Corporation's (CRC) carbon capture project (CalCapture) is planned to capture CO_2 from the 550 MWe natural gas combined-cycle plant located in CA with a total of 1.4 M tons per year captured and stored. EPRI, CRC, and Fluor are working together on a FEED study based on Fluor's amine-based Economize FG Plus process. The captured CO_2 will be either stored or used for enhanced oil recovery in the co-located Elk Hills Oil Field.

2 Petra Nova

- **Operational**
- **Suspended 2020**
- **Restarted Sept. 2023**

Petra Nova Carbon Capture is the world's largest post-combustion CO_2 capture system. Production Unit 8 of the W.A. Parish power plant near Houston, Texas, was retrofitted with a 1.4 Mtpa post-combustion CO_2 capture facility. The captured CO_2 is transported via pipeline to an oil field near Houston for enhanced oil recovery.

3 Cleco Diamond Vault

- **Advanced Development**
- **Expected Operation: 2028**

Cleco Power has announced funding for a FEED study to retrofit its Madison-3 unit with CCS technology at the Brame Energy Center in LA. Cleco expects construction to begin in 2025 and operations to begin in 2028.

4 Plant Barry

- **Advanced Development**
- **Expected Operation: 2030**

GE Vernova will complete a US DOE-sponsored FEED study for carbon capture of a 25-MW unit of Southern Company subsidiary Alabama Power's James M. Barry Electric Generating Plant. The storage component is still under evaluation. Commercial deployment is planned for 2030.

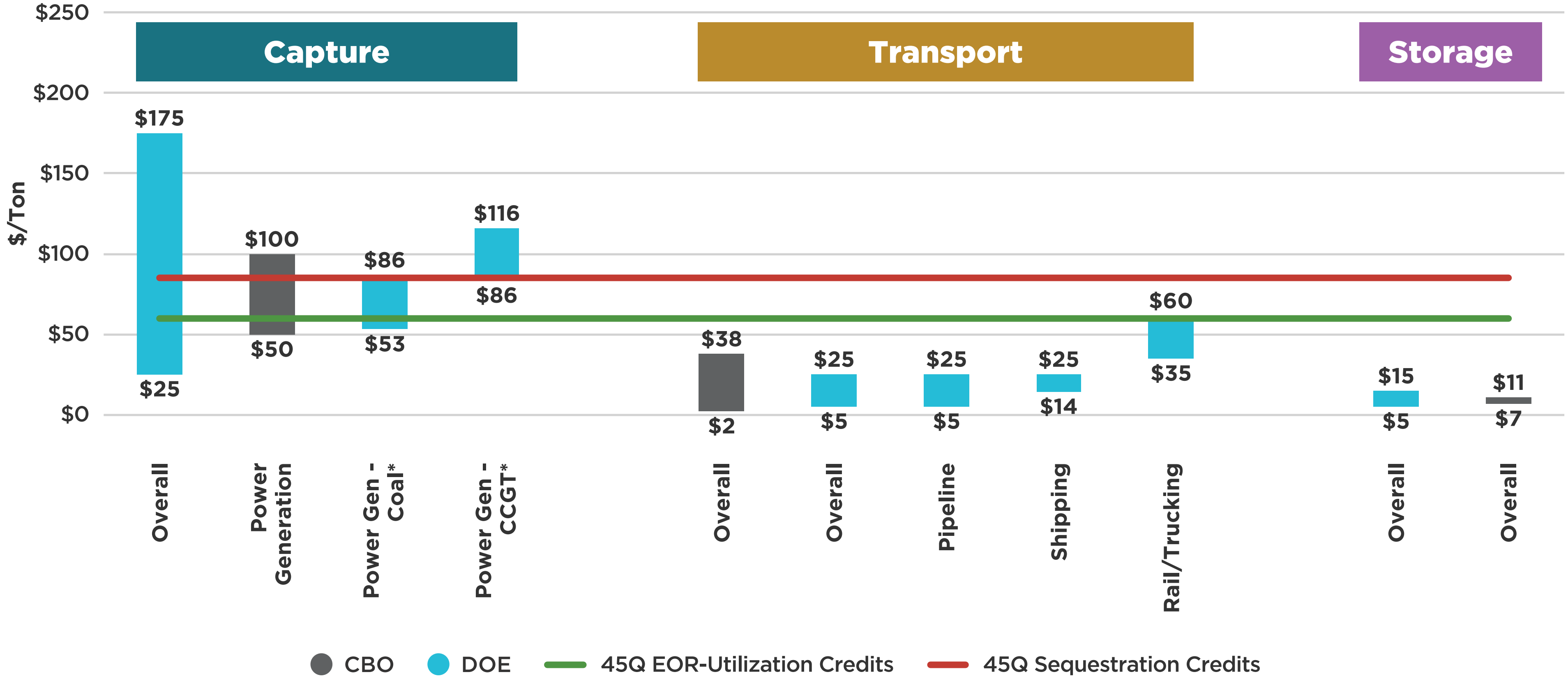
5 ION Polk Power Station

- **Advanced Development**
- **Expected Operation: 2040**

Tampa Electric Company is spearheading a FEED study in partnership with ION Clean Energy Inc. to retrofit post-combustion CO_2 capture technology at the existing Polk Power Station in Florida. The project aims to capture approximately 3.7 M metric tons of CO_2 annually, using ION's innovative solvent (ICE-31), which has demonstrated a minimum of 95% CO_2 capture efficiency in NGCC environments. The project receives funding from DOE and non-DOE sources with a total value of nearly $7M.

Note: FEED means front-end engineering and design.
Sources: Global CCS Institute; *Power* magazine; Partners for Environmental Progress; Yale Climate Connections

Figure 1.4: **Ranges of Carbon Capture and Storage Costs by Activity and IRS 45Q CCS Tax Credit Levels by CO_2 End Use ($/Ton)**



Costs shown do not reflect a 20%+ reduction in net power output for parasitic steam and power loads required for CO_2 capture.

Notes: Values color-coded to show source. *Retrofits. CBO costs represented in 2019$; DOE costs not specified by "as of" year. EOR means enhanced oil recovery.

Sources: Congressional Budget Office; DOE

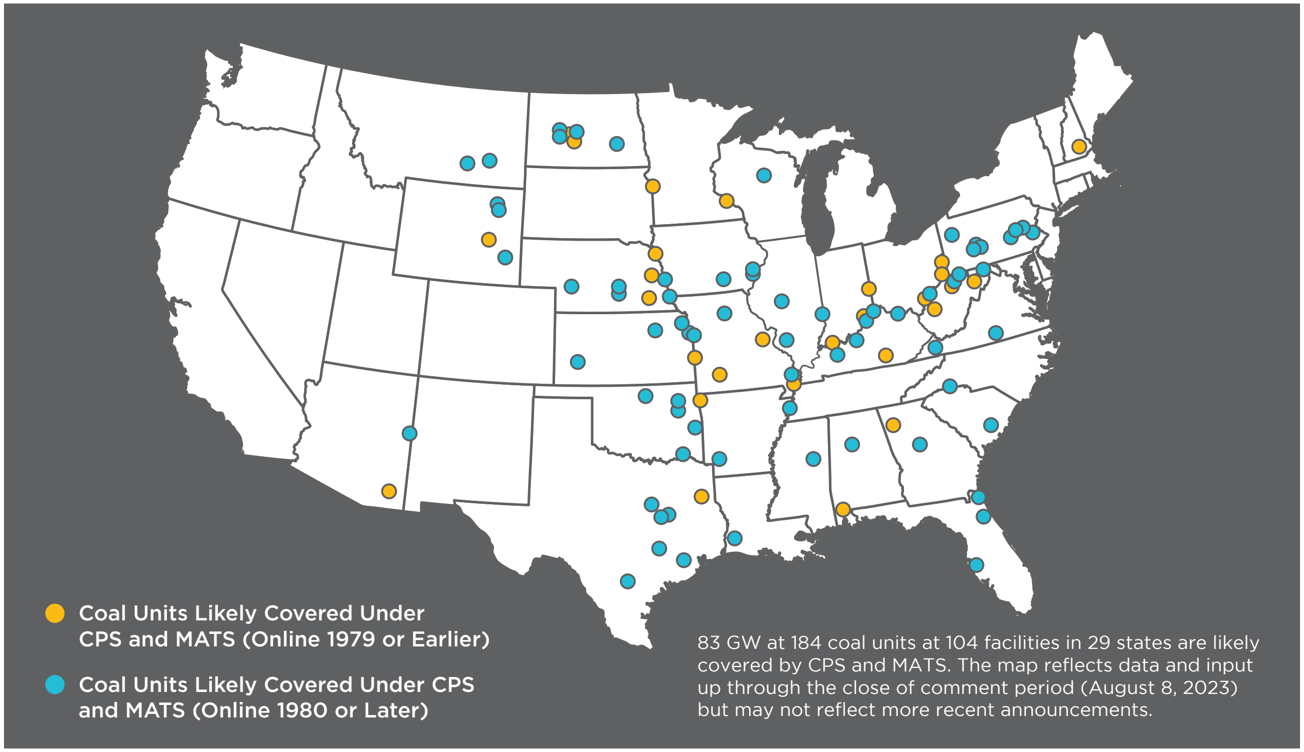
Challenges to the Proposed Rule

Upon release of the rule, 24 state attorneys general and other parties filed an unsuccessful emergency appeal to stay the rule. However, the D.C. Circuit federal appeals court ordered an expedited case with briefs submitted in September and October 2024.

- Opponents argue that CCS is not adequately demonstrated, and EPA did not show that all three elements—capture, transport, and sequestration—can be deployed by 2032 nor is 90% capture "achievable."
- EPA points to several existing and proposed plants that have achieved or are designed to achieve high CO_2 capture rates. It also argues that the rule is within its jurisdiction as the BSER applies only "inside the fence line" (although one might argue that required non-plant CCS infrastructure is not within the purview of the plant operator).

Unlike prior actions like the Clean Power Plan, there is to date no stay of the rule, which may lead to units closing sooner than later or make other irrevocable decisions, including decisions not to construct new gas-fired units. This may be exacerbated by EPA's other, less discussed rulemakings affecting the sector (see Less Discussed section later). On October 16, the Supreme Court declined to stay the rule pending appeal.

Figure 1.5: **EPA's Assumed Coal-Fired Plants (as of 2039) Potentially Covered Under New GHG Emissions Standards (CPS) and Mercury and Air Toxic Standards (MATS) Updates**



As of August 2024, there were 169 GW of conventional coal-fired generation net summer capacity.

When it released the GHG rule, EPA assumed that over the next 15 years, 103 GW of such capacity have announced plans to retire or convert to natural gas. Of the remainder, 36 GW will be more than 60 years old by 2039.

So, while technically "covered" under the rule, much more capacity will be "affected" by the rule.

Notes: Units retiring prior to 2032 are not subject to the CPS rule. The universe is likely smaller, as many plants do not announce retirement plans this far in advance.

Source: EPA

Reliability Concerns

Given the potential impact of the rule on both existing and prospective dispatchable thermal generation, utilities, system operators, and state regulators are concerned about potential reliability impacts of the rule.

EPA points to the two additional years given for coal-fired plant compliance (to 2032) over the proposed rule to provide more time to install CCS. It also points to other flexibilities in the rule:

- **RULOF:** Some allowance to reflect localized circumstances in state plans, taking into account Remaining Useful Life and Other Factors (RULOF), and allowing emissions trading and averaging in some situations.
- **Compliance extension:** Potential compliance extension of up to one year to sources installing control technologies if they experience unanticipated delays outside of the owner or operator's control.
- **Reliability mechanisms:** The rule adds two optional, reliability-related mechanisms related to grid emergencies (short term) and those with retirement dates but a verified reliability need (see Figure 1.6).

Despite these mechanisms, some industry observers point to growing generator retirements (potentially exacerbated by the rule), growing energy demand, and the slow pace of additions (see Figures 1.7 and 1.8) with interconnection backlogs and constraints on materials and labor, despite reliability mechanisms.

Figure 1.6: **EPA's Two Optional Mechanisms to Support Reliability**

	Short-Term Mechanism	Reliability Assurance Mechanism
Covered Units	▪ New or existing units during specified grid emergencies, like extreme weather events, which can include hurricanes, wildfires, and winter storms	▪ Existing units with cease-operations dates
Rule Accommodation	▪ Units responding to emergencies have access to greater compliance flexibility for those time periods ▪ Qualifying emergencies are NERC-defined energy emergency alerts levels 2 and 3	▪ Extensions can be granted where there is a documented reliability need but is insufficient time for a state plan revision
Timing	▪ Short-lasting, mostly occurring over a few hours, and in some rare instances can last for a few days	▪ Units have access to up to a one-year extension but no longer than what is substantiated through documentation ▪ Extensions exceeding one year in duration must be addressed through a state plan revision ▪ EPA will seek FERC input for extensions longer than six months

Source: EPA

Less Discussed: Other EPA Rules Affecting Coal-Fired Generation

EPA's Clean Air Act Section 111 GHG standards were issued at the same time as three other rules as part of a suite affecting all coal plants.

These EPA rules tighten and broaden regulation of non-GHG air emissions as well as water and solid waste pollutants. Those rules include the following:

- A final rule updating the Mercury and Air Toxics Standards for coal-fired power plants, tightening the emissions standard for toxic metals by 67% and finalizing a 70% reduction in the emissions standard for mercury from existing lignite-fired sources. The rule also reduces limits on particulate matter from 0.03 to 0.01 pounds per MMBtu. EPA's analysis suggests that 5 GW of operational capacity will need to comply by 2028.
- A final rule to reduce pollutants discharged through wastewater from coal-fired power plants by more than 660 million pounds per year. The rule sets a zero-discharge standard for flue gas desulfurization wastewater. EPA estimates this will affect about 232 power plants.
- A final rule will require the management of coal ash that is placed in areas that were unregulated at the federal level until now, including at previously used disposal areas that may leak and contaminate groundwater. These rules affect inactive surface impoundments, and EPA does not expect the rule to affect current power plant operations.

Figure 1.7: **Projected Annual Net Summer Capacity Additions of Natural Gas-Fired Combustion Turbine and Combined-Cycle Units by Year and % Completion (MW)**

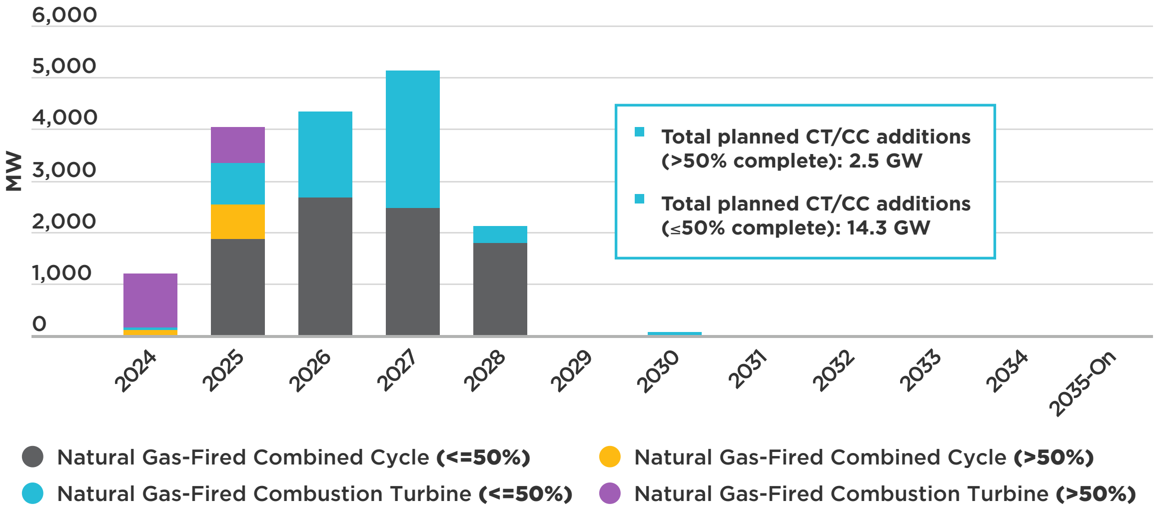
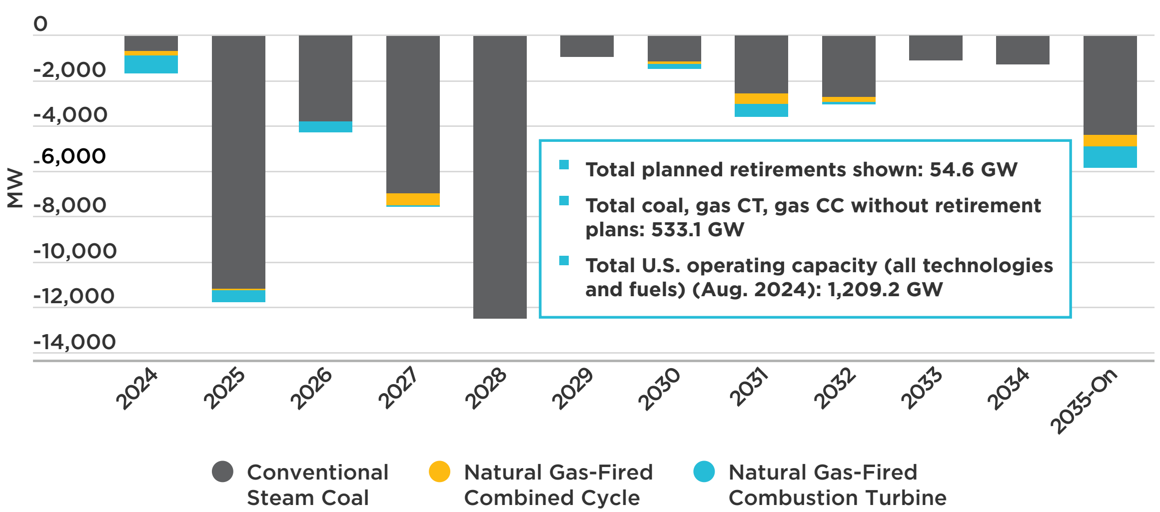


Figure 1.8: **Projected Annual Net Summer Capacity Retirements of Natural Gas-Fired Combustion Turbine, Natural Gas-Fired Combined Cycle, and Coal Units by Year (MW)**



Note: Excludes facilities with a total nameplate capacity <1 MW.
Sources: EIA data (as of Aug. 2024); ScottMadden analysis

IMPLICATIONS

Even before the EPA rule, coal-fired power plants have been retiring due to age and market forces, as well as increasing pressure from environmental regulation and some stakeholder segments seeking more rapid decarbonization.

The tightening of emissions standards on new gas-fired units and the hinted but unknown regulatory framework for existing gas units injects some uncertainty, particularly as the industry has been leaning on those units for dispatchability and flexibility.

System planners and operators must continue to prepare for alternative resource mixes over the long term and will need to seek creative solutions—energy storage, demand-side options, unit duty-cycle management (to avoid excursions that run afoul of the capacity factor-based structure)—to manage reliability and minimize operating costs.

Sources:

EPA, Presentation on Final Carbon Pollution Standards to Reduce Greenhouse Gas Emissions from Power Plants (Apr. 25, 2024); EPA News Release, "Biden-Harris Administration Finalized Suite of Standards to Reduce Pollution from Fossil Fuel-Fired Power Plants" (Apr. 25, 2024); EPA Fact Sheet, "Carbon Pollution Standards for Fossil Fuel-Fired Power Plants Final Rule: Support for Reliability" (Apr. 2024); EPA, https://www.epa.gov/stationary-sources-air-pollution/nonregulatory-public-docket-reducing-greenhouse-gas-emissions; EPA Docket ID EPA-HQ-OAR-2024-0135, at https://www.regulations.gov/docket/EPA-HQ-OAR-2024-0135; Center for Strategic and International Studies, "What Happened to Hydrogen in the EPA's Power Plant Rule?" (June 12, 2024); Power magazine, "Federal Court Rejects Stay on EPA's Carbon Pollution Standards in Setback for Power Industry" (July 23, 2024); *Power* magazine, "Supreme Court Showdown: EPA Defends Carbon Capture Amid Power Industry Backlash" (Sept. 4, 2024); *Power* magazine, "Supreme Court Showdown: EPA Defends Carbon Capture Amid Power Industry Backlash" (Sept. 4, 2024); Utility Dive, "EEI Joins AEP, Duke, other utilities in suing EPA over power plant greenhouse gas rule" (May 23 2024); *Power* magazine, "Federal Court Rejects Stay on EPA's Carbon Pollution Standards in Setback for Power Industry" (July 23, 2024); Vinson & Elkins; Davis Polk; Holland & Knight; *Power* magazine, "EPA Unleashes Four-Pronged Assault on Fossil Fuel Power Pollution" (Apr. 25, 2024); Global CCS Institute; Partners for Environmental Progress; Yale Climate Connections; Congressional Budget Office, Carbon Capture and Storage in the United States (Dec. 2023); DOE, Pathways to Commercial Liftoff: Carbon Management (Apr. 2023); EIA data (as of Aug. 2024); SCOTUSBlog, at https://www.scotusblog.com/2024/10/supreme-court-allows-epa-emissions-rule-to-stand-while-litigation-continues/; ScottMadden analysis

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FERC Expands Planning Horizons

New FERC rules seek to revisit Order 1000 approaches and facilitate transmission siting.

KEY TAKEAWAYS

FERC commissioners have been unified in their concern about the pace of transmission development and have been actively pursuing transmission reform for several years. This has led to several important rulemakings in spring 2024.

Order 1920's transmission planning and cost allocation reforms are the first significant rules on this topic since Order 1000, but the potential friction between federal and state domains will likely lead to continued debate over the rule's implementation.

It remains to be seen whether and how FERC's second attempt at backstop siting authority for interstate facilities will be enforced, given the frictions mentioned above and absence of a track record on its use under 2005's Energy Policy Act.

FERC Moves Ahead on Transmission Reform

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. FERC was concerned that even with the Order 1000 requirements and related processes:

- Transmission planning was not sufficiently long term and forward looking to meet needs driven by a changing demand and resource mix.
- The absence of longer-term planning was resulting in piecemeal transmission expansion to serve near-term needs, causing inefficient investments in infrastructure and potentially higher costs for customers.

The FERC docket resulted in the promulgation on May 13, 2024, of Order 1920, which the Commission deemed needed to identify long-term transmission needs, account for "determinants" of those needs, and consider a broader set of benefits in meeting those needs.

Requiring Long-Range Planning

The central requirement of Order 1920 was to mandate regional planning, using best available data, that looks ahead at least 20 years to develop projections of long-term transmission needs.

- This long-term planning must occur at least every five years. Transmission facilities in this process must be selected (if at all) within three years of the beginning of a planning cycle.
- Several RTOs, including the Midcontinent ISO, PJM, and ISO New England, already prepare long-term studies to inform planning needs. This would apply these processes to all FERC-jurisdictional transmission providers.

These long-range plans must be derived from at least three “plausible and diverse long-term scenarios.” FERC defines plausible as “reasonably captur[ing] probable future outcomes.” Diverse means that providers must distinguish distinct facilities or benefits in each scenario.

- To recognize impacts of weather-related reliability issues, each scenario must run at least one sensitivity analysis of high-impact, low-frequency events, such as wide-area generator or transmission outage due to extreme weather.
- Scenarios must incorporate seven categories of factors that may affect transmission needs (see Figure 2.1). Three of these may not be discounted, but four may be weighed (i.e., some discretion in application).

Figure 2.1: **Seven Scenario Factors for Long-Range Transmission Planning**

1. **Laws and regulations affecting the resource mix and demand. These include obligations, incentives (e.g., tax credits), equity and justice laws, and/or restrictions that will affect new or existing generation or demand**
2. **Laws and regulations on decarbonization and electrification**
3. **State-approved integrated resource plans and expected supply obligations for load-serving entities**
4. **Trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies, but not an endorsement of any fuel or technology**
5. **Retirements beyond those that have been publicly announced, with flexibility to account for generation facilities age, projected costs and revenues, emissions profile, and any laws and regulations that may affect continued operation**
6. **Generator interconnection requests and withdrawals, but transmission operators/providers are permitted to determine whether certain interconnection requests are speculative or duplicative and unlikely to affect long-term transmission needs**
7. **Utility and corporate commitments and federal, state, local, and federally recognized tribal policy goals that affect long-term transmission needs**

Not To Be Discounted **May Be Weighed**

Source: Order 1920

Evaluation Process and Transparency

Once scenarios are examined, planners must develop an evaluation process and selection criteria for long-term facilities. This process must include “good faith efforts” to engage state authorities and seek (but not necessarily obtain) support.

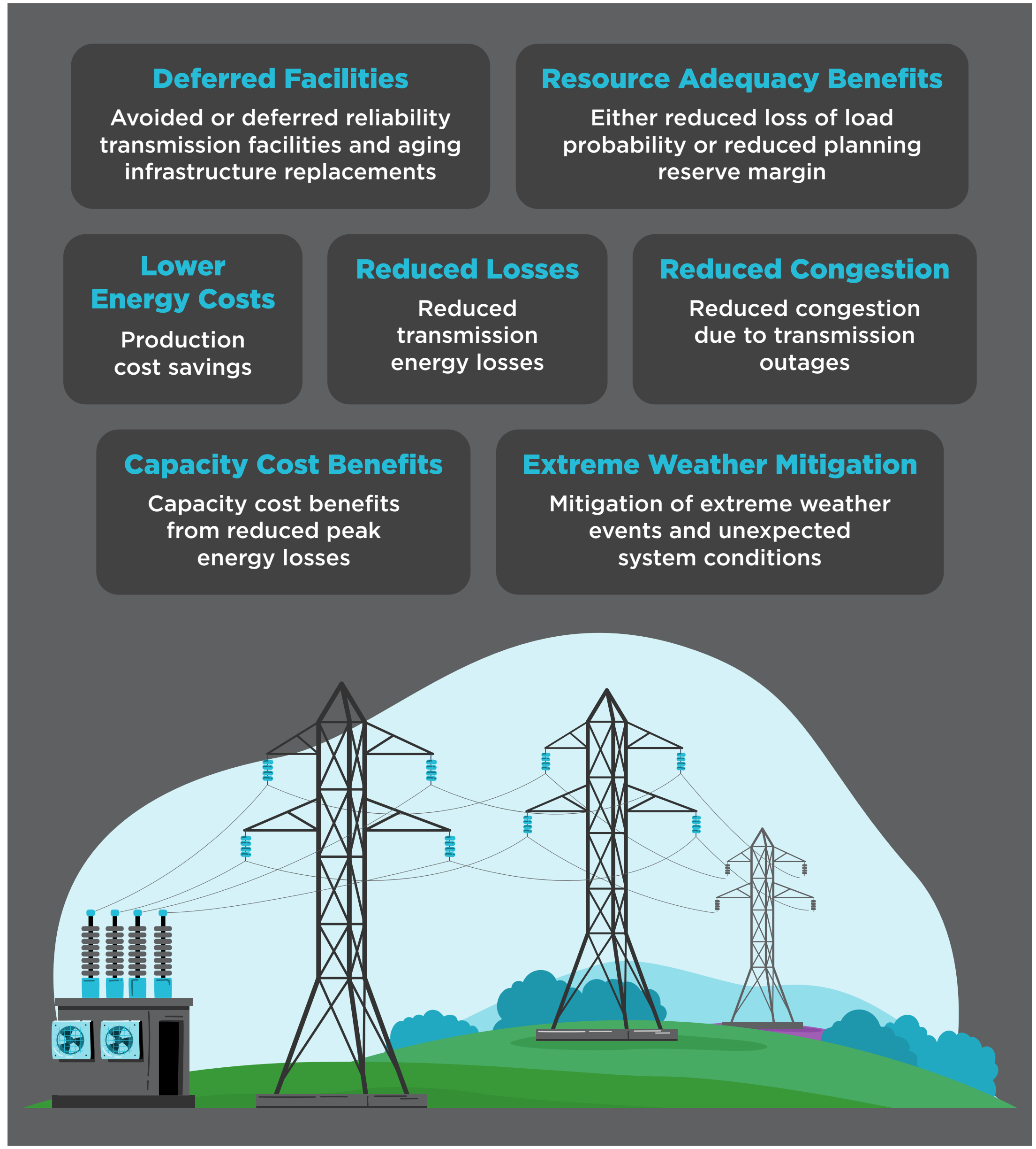
- Evaluation processes must measure at least seven specific economic and reliability benefits (see Figure 2.2).
- Processes must be “transparent, not unduly discriminatory, and seek to maximize benefits accounting for costs over time without overbuilding facilities.”

For transparency, the process must define certain decision-making points in the process and clarify the scorecard.

Specifically, it must:

- Specify when providers will accept facility proposals, including from non-incumbents
- Estimate costs and benefits of proposed facilities
- Designate a point in the evaluation process to determine whether to select identified long-term facilities (note: the process may result in no facility selection)
- Ensure determinations are “sufficiently detailed” for stakeholders to understand why a facility was or was not selected

Figure 2.2: **Long-Term Transmission Facilities Benefits to Be Evaluated Under Order 1920**

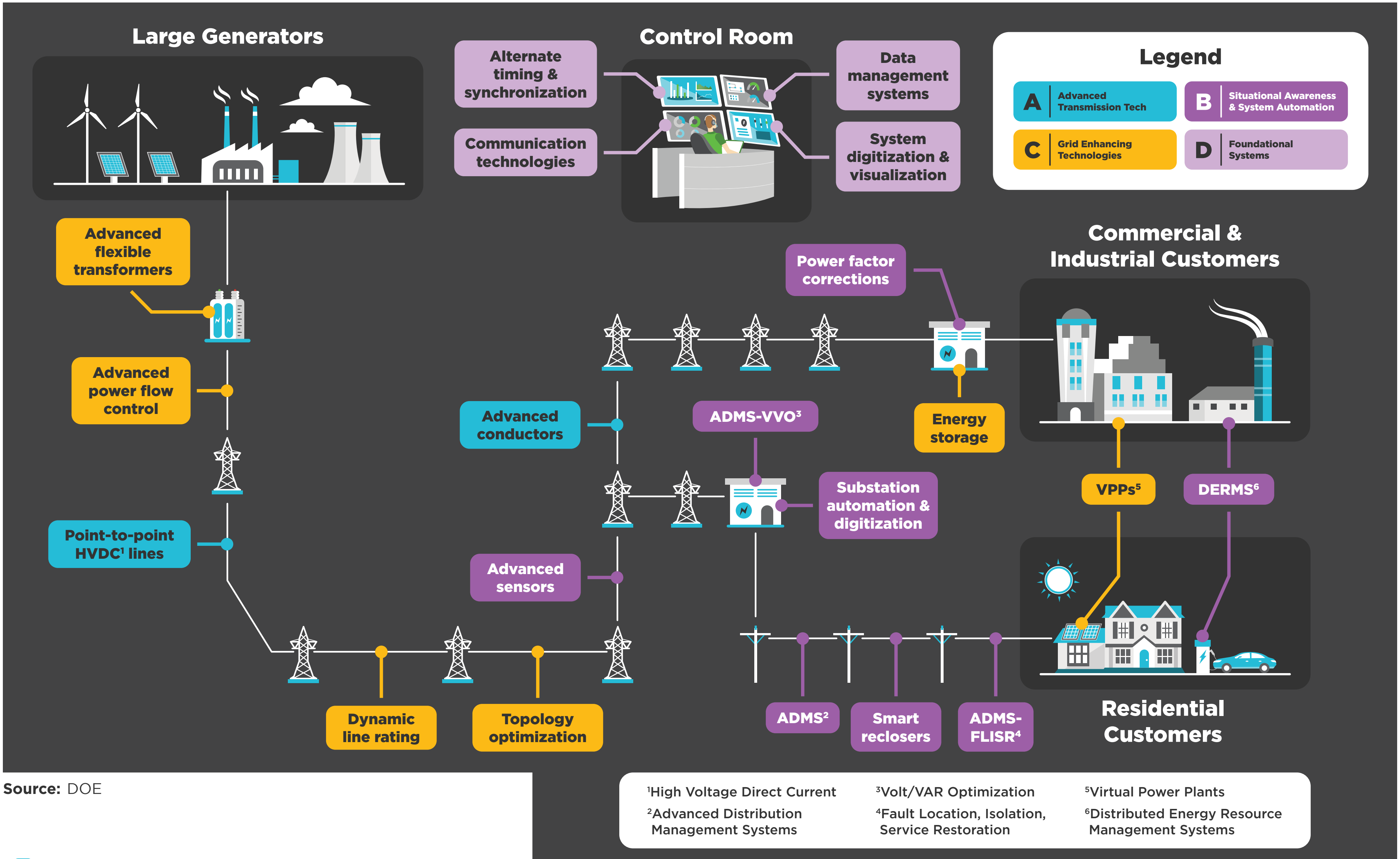


Source: Order 1920

Figure 2.3A: **Illustrative Overview of Advanced Grid Technologies (Including Grid-Enhancing Technologies)**

Order 1920 requires consideration of grid-enhancing technologies (GETs). Some examples are shown below.

Meanwhile, in Q1 2024, states including VA, ME, MN, and NY are assessing GETs, while CT and NH are considering initiating studies of these technologies.



Source: DOE

See technology definitions on next page

Figure 2.3B: **Selected Advanced Grid Solutions Classified as GETs**

Advanced Grid Solution	Definition
Dynamic Line Rating (DLR)	Real-time calculation of a transmission line's thermal capacity (i.e., power carrying capacity) based on local conditions (conductor temperature, ambient weather conditions, line sag); dynamic rating helps increase effective capacity versus more conservative static and ambient adjusted line ratings
Advanced Power Flow Control (PFC)	Change power flow direction through adjusting line reactance. In a meshed network, this can redirect power from overloaded lines to lines with available capacity; advanced PFCs are more compact, faster, and efficient than older PFCs
Topology Optimization	Software that can identify optimal reconfiguration of the system when there is a change in transmission assets to more flexibly and efficiently operate the grid
Energy Storage (as a T&D asset)	Storage solutions sited within the transmission or distribution systems with the use case to defer or offset transmission and distribution capacity expansion, support peak load management, and/or provide other grid services to enhance system resilience and reliability
Advanced Flexible Transformers	Transformers that can alter their voltage or impedance while energized, through integrated electromechanical or power electronic mechanisms, which improves system efficiency and provides power flow control capabilities. Some flexible designs also enable a single transformer to replace multiple transformers within a utility's footprint, lowering overall costs and enhancing resiliency
Virtual Power Plants (VPPs)	Platforms that aggregate distributed energy resources to provide flexible supply and demand resources to the grid

Source: DOE

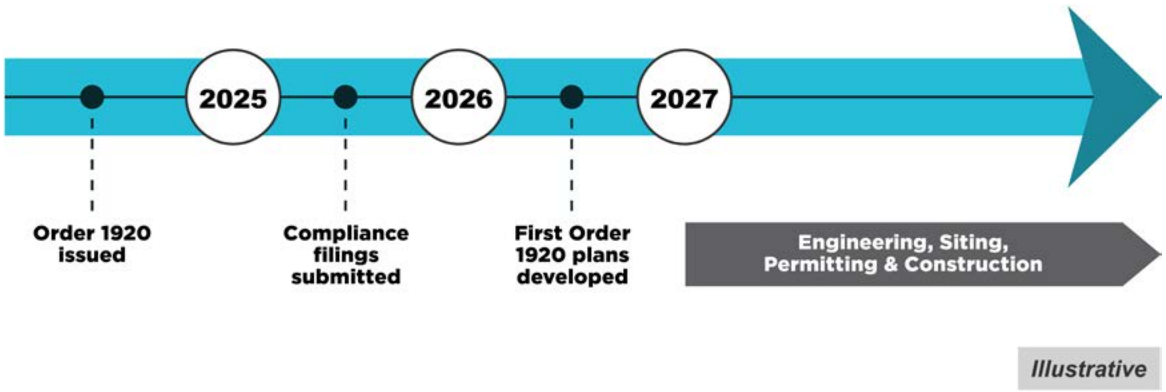
Cost Allocation: State Agreement Encouraged But Not Mandated

Order 1920 does not require state agreement on cost allocation for regional transmission facilities. However, transmission providers must have a one-time, six-month engagement period to serve as a forum for negotiation on a cost-allocation method or state agreement process that allows for meaningful participation by state entities.

Transmission providers are, however, required to provide one or more long-term regional transmission cost-allocation methods for a single facility, or portfolio of facilities, as an ex-ante (assumed) regional cost-allocation method for long-term transmission facilities proposed through the planning process.

Through these provisions, FERC is managing state involvement and ability to object to allocation. So, while transmission providers are permitted to include a state agreement process for cost allocation, it cannot be the sole cost-allocation method. In the absence or failure of a state agreement process or if the state agreement process is found by FERC to be unreasonable, unjust, or unduly discriminatory or preferential, the ex-ante long-term regional cost-allocation method will serve as a "backstop."

Figure 2.4: **Best Case Order 1920 Implementation Timeline**



Source: DOE

- **FERC denied rehearing of Order 1920; however, substantial litigation of the rule is expected. Many criticisms of Order 1920 made by Commissioner Christie in dissent are likely to be made in litigation over the rule.**
- **Much current debate focuses on whether FERC exceeded its jurisdiction given the reversal of the Chevron doctrine (deferring to agency interpretation of statute) and the major questions doctrine (agencies cannot regulate matters of "vast political or economic significance" without clear authorization from Congress).**
- **Transmission providers are to submit compliance plans by end of May 2025. With three new FERC commissioners, it will bear watching how those plans are received and how Order 1920 is fleshed out in commission decisions.**
- **Even if no lengthy litigation ensues, the earliest beginning of transmission development and construction would not occur until 2027 (see Figure 2.4).**

Cost Allocation: State Agreement Encouraged But Not Mandated (Cont.)

Any proposed ex-ante backstop cost-allocation methods must conform to Order 1000 cost-allocation principles, with some key exceptions:

- Costs may not be allocated according to project type (i.e., reliability vs. economic vs. public policy needs driven), a key change from Order 1000 principles. This raises concerns that individual state policy preferences will be socialized across a region.
- Cost allocations based on state agreement need not meet Order 1000 principles but must be shown to allocate costs in a manner "at least roughly commensurate with estimated benefits," a key Order 1000 principle.

Industry Reactions

The rule is controversial, with Commissioner Christie dissenting, claiming it shifts the interconnection and network upgrade costs of projects driven by public policies or corporate preferences onto ratepayers who may not have agreed to those policies or preferences. He also argues that the order infringes on the authority of states over energy resource mixes.

NARUC expressed disappointment, citing a significantly diminished state role envisioned by the order.

Some positions supporting and critiquing the rule are summarized in Figure 2.5.

Figure 2.5: **Reactions to Order 1920 as Promulgated**

Proponents

- Attempts to push a "recalcitrant" industry to do more, especially in interregional planning
- Will remedy the forward and comprehensive planning that is not occurring, resulting in "inefficient piecemeal transmission expansion to meet only near-term needs while foregoing projects with better net benefits"
- Clarifying consistent benefits categories in planning ultimately improves net benefits to consumers

Critics and Opponents

- Unduly preferential toward certain types of generators (i.e., wind and solar)
- Does not provide a "just and reasonable" replacement rate because it:
  - Serves the profit-making interest of the developers of certain types of generation
  - Shifts interconnection and network upgrade costs of projects driven by public policies or corporate preferences onto ratepayers who may not have agreed to those policies or preferences
- Infringes on the authority of the states over energy resource mixes
- Disappointed by the significantly diminished state role envisioned by the order and hope that there will be future opportunities to ensure that state voices are heard

Sources: Press releases; industry news; Order 1920

Order 1977: Another Crack at Federal Backstop Siting

Siting transmission facilities has been a perennial challenge for transmission, especially long-distance interstate projects. In Order 1977, FERC, supported by terms of the Inflation Reduction Act of 2022 (IRA), issued a rule to reinvigorate FERC's limited transmission siting authority.

Under Order 1977, FERC can issue siting permits for proposed interstate transmission facilities located in DOE-designated national interest electric transmission corridors (NIETCs) (see Figure 2.6) in the following circumstances:

- A state does not have the authority to approve the siting of the facilities or consider the interstate or interregional benefits.
- The applicant is a transmitting utility that does not qualify to apply in a state.
- A state has not decided on an application within one year or has denied an application.
- FERC finds that the facilities are in the public interest, are used for interstate commerce, reduce transmission congestion, are consistent with national energy policy and enhance energy independence, and maximize the transmission capabilities of existing towers or structures.

Figure 2.6: **DOE's Preliminary NIETC Designations (as of August 2024)**

Source: DOE

Order 1977: Another Crack at Federal Backstop Siting (Cont.)

FERC is interested in stakeholder and landowner engagement in the siting and permitting process. Applicants for Order 1977 permits must show stakeholder engagement, a plan for engagement with environmental justice communities and Indian tribes, timely notice to affected landowners, and 14 reports on emissions, air quality, and other impacts of the facilities.

FERC's original backstop siting authority (from the Energy Policy Act of 2005) was never acted upon. The IRA attempts to make clear that FERC jurisdiction takes effect upon state denial of a transmission siting application. So, it is unclear how states will react to developers who proceed with a project pursuant to FERC ruling following state denial of a siting request. The 2005 backstop authority was challenged in the courts, and Order 1977 may face those same legal challenges.

Figure 2.7: **NIETC Designation Process and Status**

Source: DOE

IMPLICATIONS

Several RTO/ISOs have already been conducting studies of long-term trends and scenarios to inform transmission needs and considerations for prioritizing location and types of grid infrastructure. Order 1920 seeks to formalize that with specific requirements and factors that must be considered. Its broad application will require all transmission providers to consider plausible scenarios, planning processes, tools and techniques, stakeholder engagement, and other factors as they consider their respective compliance plans.

While designated transmission infrastructure, even on the most optimistic timeline, will not be identified for years, the planning cycle will come quickly and require adaptation and change management to implement regional compliance plans. Many hope some existing approaches will only require tweaking to satisfy Order 1920. It bears watching how a new panel of FERC commissioners will receive these plans.

Sources:

ScottMadden, Transmission in the United States – What Makes Developing Electric Transmission So Hard? An Update (July 2024); FERC Order 1920; Foley Hoag, “Order No. 1920: A Guide to FERC’s Landmark Transmission Planning Order” (May 16, 2024); Troutman Pepper, “High-Level Summary of FERC Order No. 1920 on Transmission Planning and Cost Allocation” (May 21, 2024); Vinson & Elkins, “FERC Issues Final Rules on Electric Transmission Planning, Cost Allocation, and Backstop Authority Evaluation Procedures” (May 14, 2024); PowerGrid International, “FERC’s ‘watershed’ transmission rules are here. Here’s what to know about Orders 1920 and 1977” (May 13, 2024); R Street Institute, “FERC Hath Spoken Transmission” (May 14, 2024); NARUC Press Release, “NARUC Expresses Disappointment in FERC’s Order on Transmission Planning” (May 14, 2024); *Power*, “The Chevron Deference Is Dead. What Does It Mean for the Power Sector?” (July 2, 2024); Utility Dive, “Supreme Court’s Chevron, Corner Post Decisions Could Delay Energy Investments, Spur Litigation: Analysts” (July 2, 2024); FERC Order 1977; FERC Staff Presentation, “Applications for Permits to Site Interstate Electric Transmission Facilities” (May 13, 2024); Bracewell, “Order No. 1977: FERC Finalizes Backstop Transmission Siting Reforms” (May 22, 2024); Dept. of Energy, Pathways to Commercial Liftoff: Innovative Grid Deployment (Apr. 2024); NC Clean Energy Technology Center, 50 States of Grid Modernization: Q1 2024 Quarterly Report Executive Summary (May 2024)

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Long-Duration Energy Storage

New technologies move closer to market deployment.

KEY TAKEAWAYS

Battery storage added to the electric grid in recent years is primarily lithium-ion batteries with a discharge duration of four hours or less.

Long-duration storage technologies—capable of providing more than 10 hours of discharge—will be needed to integrate higher penetrations of renewables.

Some technologies, such as the iron-air battery system being developed by Form Energy, may eventually provide up to 100 hours of battery storage.

Key milestones to monitor as the industry matures include technology performance improvements, cost declines, regulatory support, and supply chain developments.

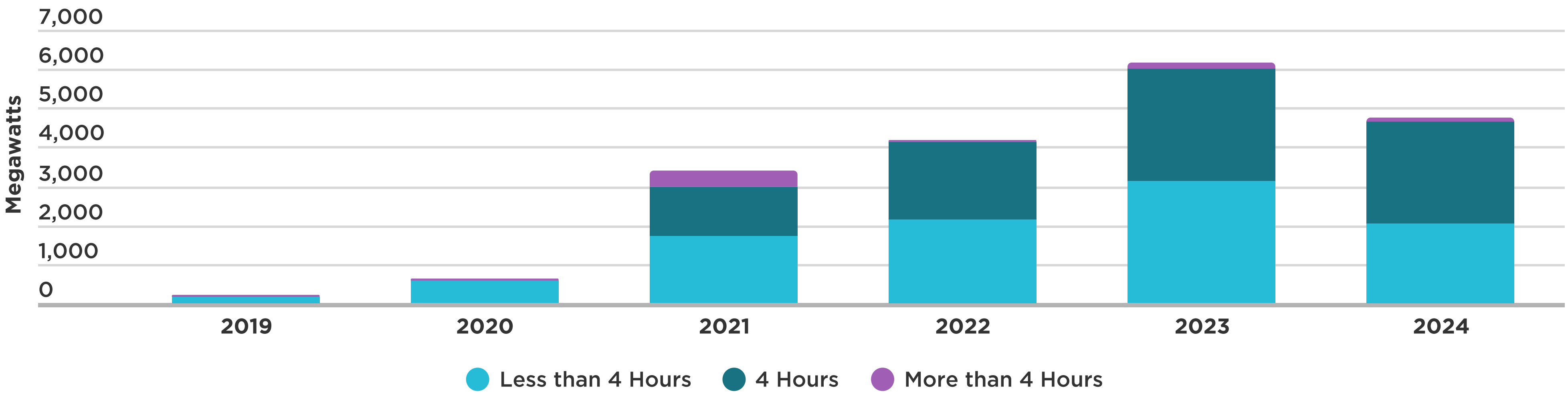
Long-Duration Storage Needed to Integrate High Renewable Penetration

The United States has installed roughly 20 GW of storage capacity since 2019. This new capacity has overwhelmingly been short-duration lithium-ion batteries. As a result, more than 90% of this capacity can provide discharge durations of only four hours or less (see Figure 3.1).

Integrating higher penetrations of renewables will require longer discharge durations. While no standard definition exists, long-duration energy storage can be considered any technology capable of discharging energy for 10 hours or longer. The need for long-duration storage may be significant. California estimates that retiring the state's natural gas generation assets will require 37 GW of long-duration storage by 2045.

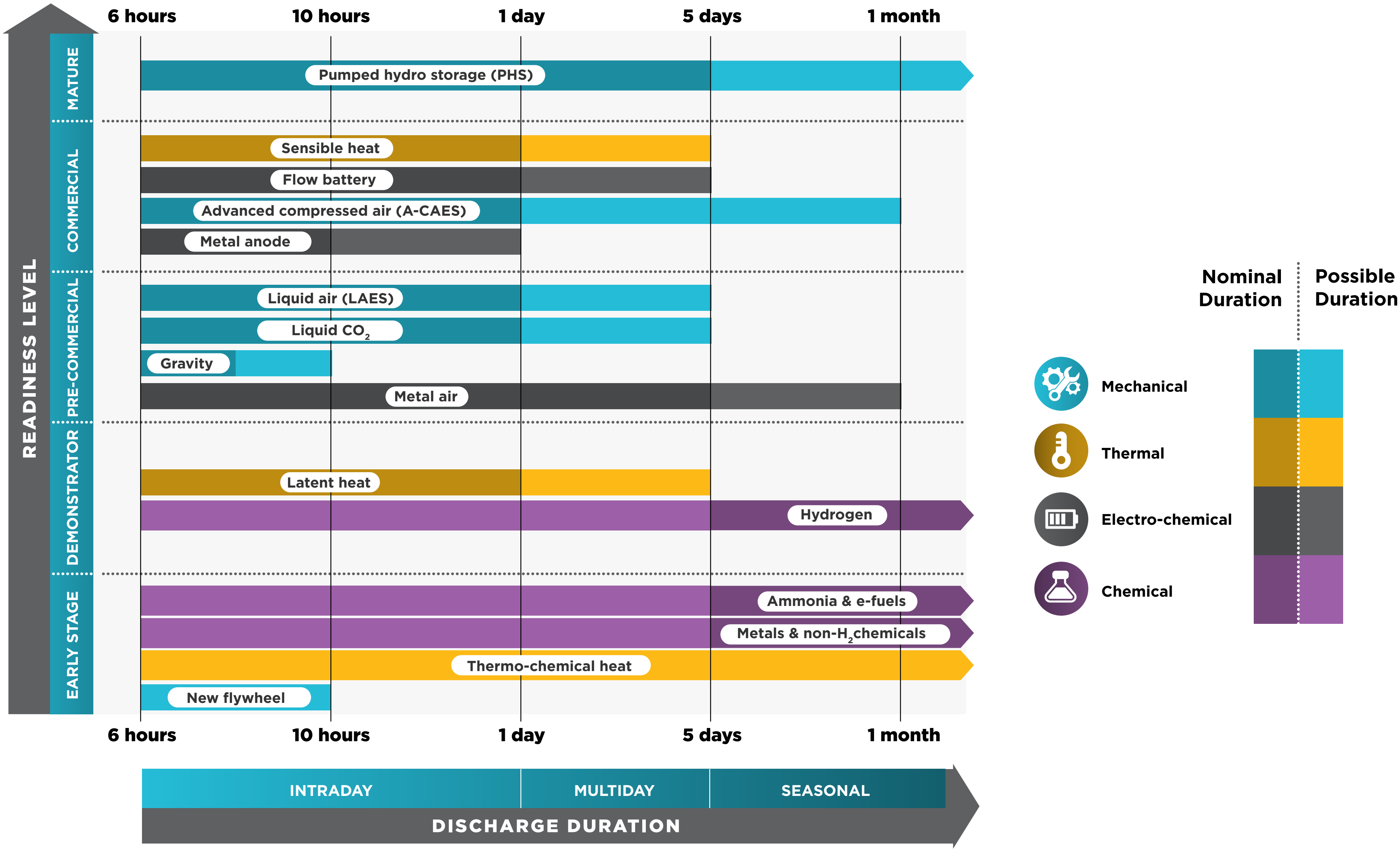
Not surprisingly, a variety of long-duration storage technologies are in various stages of development (see Figure 3.2). Further, the convergence of innovation, investment, and regulatory commitments may result in long-duration storage quickly becoming a common resource for electric utilities.

Figure 3.1: **U.S. Installed Storage Capacity by Year and Duration, 2019 through July 2024**



Sources: EIA; ScottMadden analysis

Figure 3.2: **Long-Duration Storage Technology Readiness Level and Discharge Duration**



Source: Future Cleantech Architects and Long Duration Energy Storage Council

Public Policy and Market Interest Catalysts

In July 2021, the DOE announced the "Long Duration Storage Shot" as part of the broader Energy Earthshot Initiative. Designed to accelerate breakthroughs, the long-duration storage effort establishes a target to reduce the cost of 10+-hour grid-scale energy storage systems by 90% from a 2020 baseline by 2030.

Long-duration energy storage was also bolstered by the passage of the Inflation Reduction Act, which provides tax credits for clean energy manufacturing and allows standalone storage projects to receive the federal investment tax credit.

In addition to policy support, states and electric utilities are beginning to explore long-duration storage technologies and their potential role in the clean energy transition. Numerous studies and projects have been announced in multiple jurisdictions over the last two years (see Figure 3.3).

A growing number of startup companies are developing and providing long-duration storage solutions—including multiday offerings. While Form Energy may be the most visible, there are multiple other companies operating long-duration storage facilities or deploying demonstration projects (see Figure 3.4).

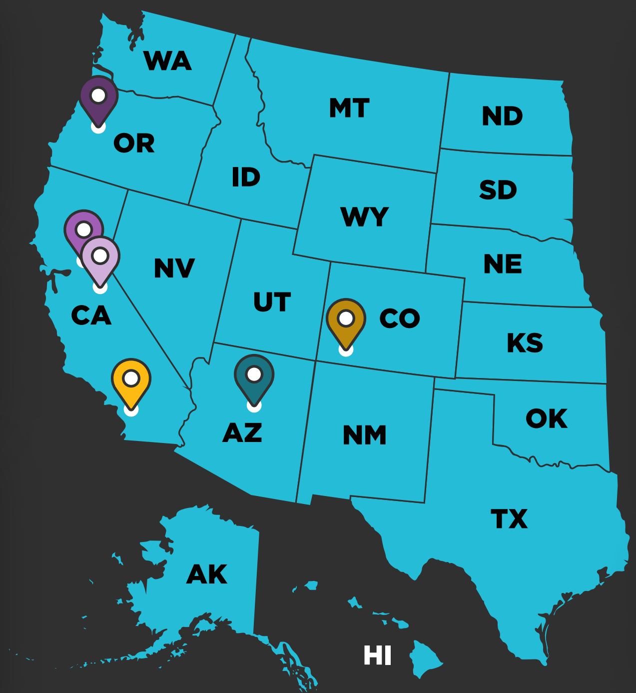
Figure 3.3A: **Recent Long-Duration Storage Activity and Development (Western U.S.)**

Western U.S.

Aug. 2024: Oregon PUC approved Idaho Power's intent to explore a 5 MW long-duration storage pilot between 2024 and 2028. Long-duration storage was selected as a resource in every portfolio in the company's 2023 IRP.

Feb. 2024: PG&E and Energy Vault started construction of an 8.5 MW/293 MWh lithium-ion battery plus hydrogen system in Calistoga, CA, to deal with power shutoffs during wildfires.

Aug. 2024: After recent legislation authorized centralized procurement, California announced it will solicit 2 GW of long-duration storage (1 GW of 12+ hour duration and 1 GW of multiday duration). In June 2024, the state awarded $26.7M for long-duration storage projects from Redlfow, RedoxBlox, and Noon Energy.



Mar. 2024: Hydrostor reached key permitting and interconnection milestones for their 500 MW/4,000 MWh advanced compressed air storage system project being deployed in Kern, CA. Previously in January 2023, Central Coast Community Energy signed a PPA for 1,600 MWh of energy storage.

Jan. 2023: Xcel Energy announced it will deploy a 10 MW/1,000 MWh Form Energy storage system at a retiring coal plant in Pueblo, CO. The project was awarded $35M in DOE funding.

June 2024: Salt River Project issued an RFP for two non-lithium storage demonstration projects with a capacity of 5 MW to 50 MW and duration of 10 hours.

Source: ScottMadden research

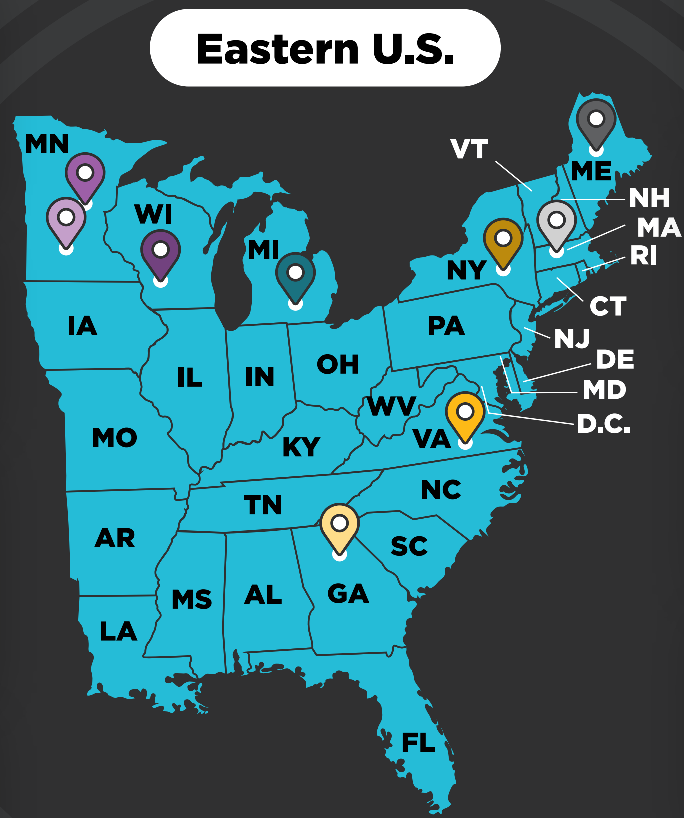
Figure 3.3B: **Recent Long-Duration Storage Activity and Development (Eastern U.S.)**

July 2023: Xcel Energy received approval to build a 10 MW/1,000 MWh Form Energy storage system at a retiring coal site in Becker, MN. The project was awarded $35M in DOE funding and a $20M grant from Breakthrough Energy Catalyst fund.

Aug. 2024: Form Energy broke ground on the company's first commercial facility—a 1.5 MW/150 MWh storage system being built in Cambridge, MN, for Great River Energy.

Aug. 2024: Wisconsin Power & Light, Madison Gas & Electric, and Wisconsin Public Service requested approval from the Wisconsin PSC to construct up to 20 MW carbon dioxide-based energy storage system near Portage, WI. The project was awarded $30M in DOE funding.

Feb. 2024: To comply with recent legislation, the Michigan PSC directed staff to develop a report focused on long-duration and multiday storage. The report is due to the legislature no later than February 27, 2025.



Aug. 2024: DOE awarded $389M to New England states for electric grid upgrades, including the world's largest battery—a 85 MW/8,500 MWh battery system—being deployed by Form Energy in Lincoln, ME.

Dec. 2023: MA Dept. of Energy Resources recommended allocating $50M to fund specific storage use cases, improve energy storage siting, and lower commercialization barriers for medium-duration and long-duration energy storage.

June 2024: NYSERDA announced more than $5M in funding for long-duration storage that can harness and provide stored renewable energy. Previously in August 2023, Form Energy was awarded $12M for a 10 MW/1,000 MWh demonstration project.

May 2024: Dominion Energy received approval to deploy a 4.94 MW/494 MWh Form Energy storage system. Dominion is also partnering with Enervue to install a 1.5 MW/15 MWh metal-hydrogen battery at Virginia State University.

June 2023: Georgia Power announced plans to deploy a 15 MW/1,500 MWh Form Energy storage system. As of July 2024, the utility was still conducting due diligence.

Source: ScottMadden research

Figure 3.4: **Select Long-Duration Storage Startup Companies**

Form Energy	▪ Form Energy is developing an iron-air exchange battery with a discharge duration of up to 100 hours. By relying on abundant materials, the company expects to be able to offer long-duration storage at a price of less than $20/kWh. ▪ In October 2024, the company raised $405M in Series F funding. In addition, the company recently completed construction of a $760M high-volume manufacturing plant in West Virginia. The new factory has started trial battery production and expects to reach an annual output of 500 MW by 2027. ▪ In August 2024, the company broke ground with Great River Energy on their first commercial scale facility (1.5 MW/150 MWh storage system). ▪ In the same month, the company announced plans for the world's largest battery in Maine (85 MW/8,500 MWh). Even more notable, CEO Mateo Jaramillo noted in an interview with Canary Media that "there will be other utility projects that get announced that are the same size or larger."
Hydrostor	▪ Hydrostor is developing an advanced compressed air energy storage technology and pursuing a development pipeline in California, Nevada, Arizona, and New York. Additional projects are being pursued in Canada and Australia. ▪ An advanced-stage project being developed in Kern, California, would be the company's third utility-scale project. The company operates a 1.75 MW/10 MWh demonstration project in Ontario and is developing a 200 MW/1,600 MWh facility in Australia. ▪ In a recent Utility Dive interview, CEO Curtis VanWalleghem noted the Hydrostor technology is bankable, but "not every market is ready for long-duration storage yet."
Noon Energy	▪ In January 2023, Noon Energy raised $28 million in Series A financing to develop a novel carbon-oxygen battery based on technology used on NASA's Mars Perseverance rover. ▪ In June 2024, the company was awarded $9M from the California Energy Commission to demonstrate a 100 kW/10 MWh system to support renewable energy storage, load balancing, and grid services that will directly benefit underserved communities. ▪ Upon future commercialization, Noon Energy is targeting a levelized cost of storage for less than $0.05/kWh.
Energy Dome	▪ Energy Dome is developing a thermodynamic energy storage system. The technology charges by drawing carbon dioxide from a "dome" gasholder, storing it as a compressed liquid, and then dispatching it by evaporating and expanding the gas through a turbine back into the gasholder. ▪ The first commercial project proposed in Wisconsin will be sited at a retiring coal plant and was awarded more than $30M in DOE funding. If approved by regulators, the 18 MW/180 MWh facility is expected to come online in 2027.
Energy Vault	▪ Energy Vault originated as a provider of the "power tower," a gravity energy storage system (GESS) that can provide 4 to 12 hours of energy storage by lifting concrete blocks to charge and lowering them to discharge. More recently, the company has transitioned into a developer offering GESS, lithium-ion batteries, and hydrogen solutions. ▪ The company is currently constructing a hybrid storage system in Calistoga, California, that combines lithium-ion batteries and hydrogen fuel cells. The project will provide 48 hours of continuous energy and a peak instantaneous power output of 8.5 MW during public safety power shutoff events.

Source: ScottMadden research

Improvements in Technology, Cost, Regulatory Support, and Supply Chain Needed

According to the DOE, long-duration storage will need to achieve certain milestones to reach technology "liftoff," defined as the point where the industry is largely self-sustaining and not dependent on significant levels of public capital.

More specifically, long-duration storage will need to meet the following three milestones:

- Demonstrate technology performance and cost curve improvements to attract sustained investment. More specifically, the DOE estimates system costs must decline 45% to 55%, and roundtrip efficiency must improve by 7% to 15% by 2030 to compete with lithium-ion storage and hydrogen.
- Secure resource adequacy compensation in markets or through public utility commission valuation. The DOE estimates the compensation must reach \$50 to \$75 per kW per year by 2030 to attract private financing. Further, realizing this value will require methodology changes in integrated resource planning, resource adequacy planning, and transmission planning.
- Develop a supply chain capable of manufacturing 3 GW annually by 2030 and 10 GW to 15 GW annually by 2035. The timing of the supply chain expansion will be closely linked to renewable penetrations.

Demonstration projects coming online in the next few years will reveal if long-duration energy storage can deliver on promised results and become a critical resource on the electric grid.

IMPLICATIONS

In recent years, energy storage capacity added to the grid has been predominantly lithium-ion batteries. While well-suited for short discharge durations, additional technologies or solutions will be needed to integrate higher penetrations of renewable energy resources.

Public policy and market interest is spurring the growth of long-duration energy storage startup companies and the deployment of pilot projects. These early deployments should provide insight into the companies and technologies best suited to serve the electric grid. At the same time, markets and regulators must begin to consider how to model, plan, and compensate long-duration energy storage when it provides unique value to the grid.

Sources:

DOE, Pathways to Commercial Liftoff: Long Duration Energy Storage (March 2023); Massachusetts Department of Energy Resources, Charging Forward: Energy Storage in a Net Zero Commonwealth (Dec. 2023); California Energy Commission, Assessing the Value of Long-Duration Energy Storage in California (Dec. 2023); Utility Dive, "California targets up to 2 GW of long-duration storage as part of 10.6 GW clean energy procurement" (Aug. 27, 2024); Utility Dive, "California agency awards $26.7M for long-duration energy storage projects" (June 18, 2024); NYSERDA, "Over $5 Million Announced for Long Duration Energy Storage Projects" (June 2024); NREL, Moving Beyond 4-Hour Li-Ion Batteries: Challenges and Opportunities for Long(er) Duration Energy Storage (Sep. 2023); The Maine Governor's Energy Office, Long-Duration Energy Storage: A review of technology options, key considerations, costs, and scenarios for the use of long-duration energy storage in Maine pursuant to Public Law 2023, Chapter 374: An Act Relating to Energy Storage and the State's Energy Goals. (Feb. 2024); Public Utility Commission of Oregon, Docket LC 48 (Idaho Power 2023 Integrated Resource Plan): Order No, 24-285, (Aug. 26, 2024); California Energy Commission, Assessing the Value of Long-Duration Energy Storage in California (Jan. 29, 2024); Hydrostor, "Momentum building for Hydrostor's Willow Rock Energy Storage Center as company reaches key permitting and interconnection milestones" (Mar. 4, 2024); Utility Dive, "Hydrostor, California community choice aggregator enter nearly $1B long-duration energy storage PPA" (Jan. 17, 2023); Utility Dive, "Form Energy's $20/kWh, 100-hour iron-air battery could be a 'substantial breakthrough'" (July 26, 2021); California Energy Commission, Backup Materials for Noon Energy Inc. (June 12, 2024); DOE, "Biden-Harris Administration Announces $325 Million For Long-Duration Energy Storage Projects to Increase Grid Resilience and Protect America's Communities" (Sep. 22, 2023); EIA, Preliminary Monthly Electric Generator Inventory (Form EAI-860M), (July 2024); Future Cleantech Architects and Long Duration Energy Storage Council, "Long duration energy storage for the power system: a diverse field of technologies eager for deployment" (Sept. 13, 2023); Utility Dive, "Alliant Energy utility wants to demonstrate nation's first CO2-based long-duration 'energy dome'" (Aug. 20, 2024); Michigan Public Service Commission, "MPSC kicks off implementation of changes made to Michigan's energy laws in 2023" (Feb. 8, 2024); Canary Media, "Form Energy set to build the world's biggest battery in Maine" (Aug. 15, 2024); Commonwealth of Virginia State Corporation Commission, Final Order in Case No. PUR-2023-00162 (May 6, 2024); Utility Dive, "SRP seeks non-lithium, 10-hour energy storage solutions to meet rising power demand" (June 27, 2024); Utility Dive, "California could need up to 37 GW of long-duration storage by 2045 to retire gas resources: report" (Feb. 6, 2024); company websites

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Low-Income Energy Affordability

States try innovative rate designs and pilots to address energy affordability.

KEY TAKEAWAYS

Home energy burden remains a significant challenge for low-income households who are disproportionally impacted by rate increases.

States are trying a variety of rate designs aimed at ensuring low-income customers have access to essential services.

Rate designs include a tiered discount rate program in Massachusetts, income-graduated fixed charges in California, and an energy affordability guarantee in New York.

Rate designs ensuring affordability for low-income customers must balance tradeoffs which include program precision, administrative feasibility, and consumer protection.

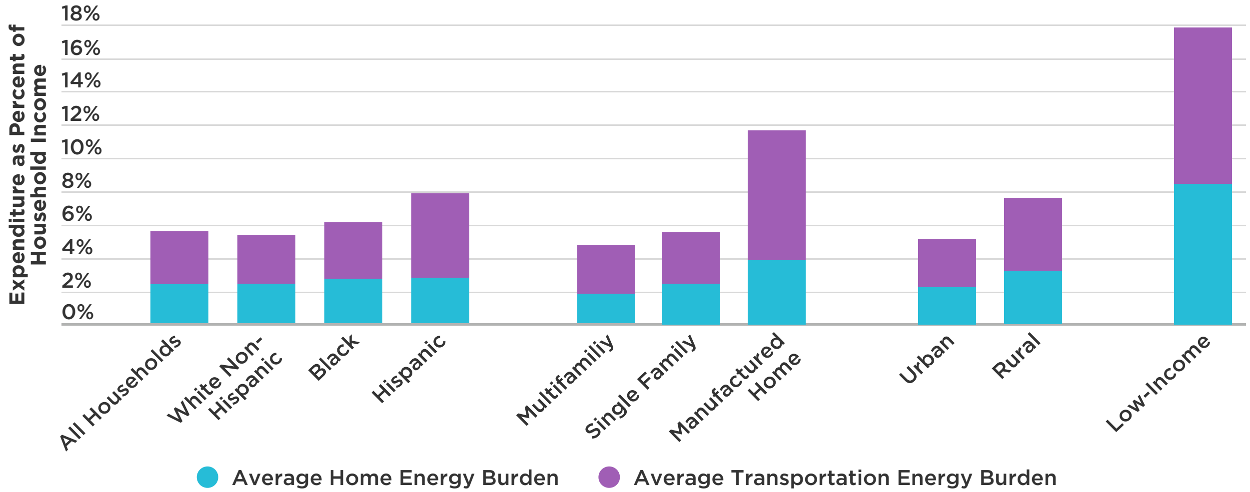
Energy Burden Challenges Low-Income Households

Ensuring affordability for low-income customers remains a top priority for utilities, regulators, and stakeholders. The rising costs associated with maintaining and transforming the grid are of a particular concern as low-income households are disproportionately impacted by rate increases.

Research from the American Council for an Energy-Efficient Economy (ACEEE) finds home energy burdens are "high" when home energy costs exceed 6% of household before-tax annual income and "severe" when the costs exceed 10%. In an analysis that includes transportation energy burden, ACEEE finds the energy burden experienced by low-income customers to be significantly higher than average households (see Figure 4.1).

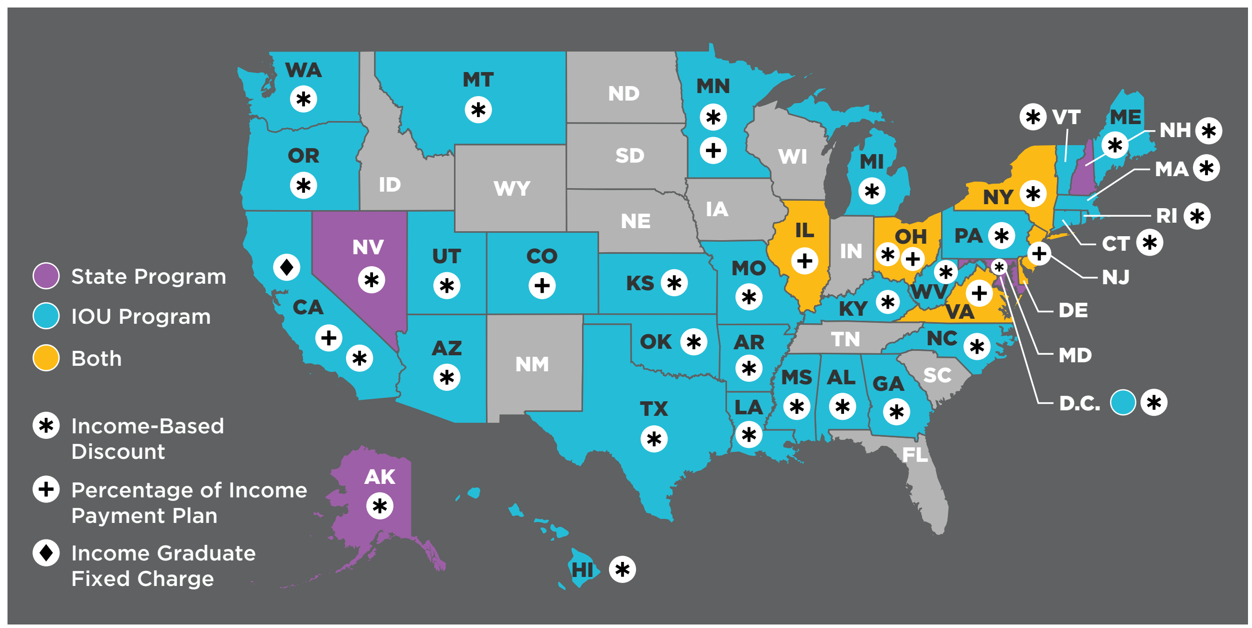
In response to this challenge, states and utilities have embarked on rate design solutions aimed at mitigating the financial burdens of low-income households (see Figure 4.2). Some approaches being implemented include income-based discounts, tailored bill assistance, or income-graduated fixed charges. This section highlights approaches being undertaken in three states—Massachusetts, California, and New York—and identifies key questions that should be considered.

Figure 4.1: **Average U.S. Combined Energy Burdens by Group (2022)**



Source: ACEEE

Figure 4.2: **Low-Income Household Electric Rate Discount Programs**



Note: As of June 2024; does not include LIHEAP, medical-based discounts, late fee exemptions, "pay-later" programs, shutoff exemptions, or charitable assistance programs.

Source: NC Clean Energy Technology Center

Massachusetts Approves Five-Tier Discount Rate

In September 2024, the Massachusetts Department of Public Utilities (DPU) approved a five-tier, low-income discount rate structure proposed by National Grid (see Figure 4.3). The tiered discount rate will replace a flat 32% discount currently available to households with incomes at or below 60% of the Massachusetts statewide median income.

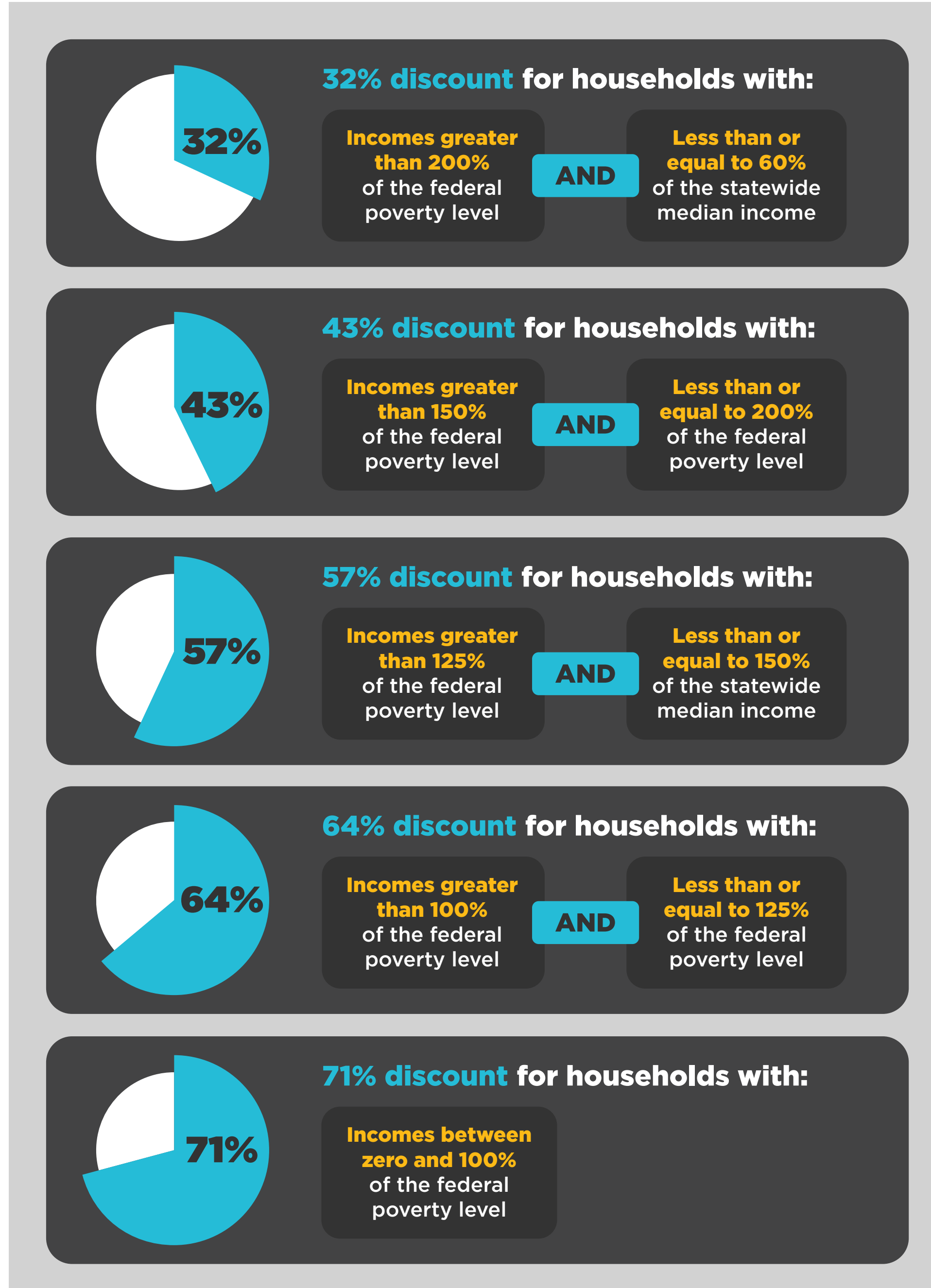
The tiered discount rate responds to a DPU directive, issued in November 2021, that electric distribution companies should explore stratifying low-income discount rates to provide an equitable discount for customers, assist the most vulnerable customers, and mitigate the potential rate shock for customers that transition from low to moderate income.

National Grid acknowledges that the tiered rates are more complex, but the approach is designed to be more equitable while keeping the electric energy burden for eligible low-income customers at approximately 3.1%. The new rate structure must be implemented no later than June 2025.

In addition, the DPU approved a performance incentive mechanism tied to enrollment target of 4,650 new, qualifying, low-income customers each calendar year. National Grid may earn up to $500,000 per year for exceeding the target or incur a penalty up to $500,000 per year for missing the target.

The DPU also plans to further investigate and potentially adjust the tiered discount rate structure in an ongoing proceeding, considering factors such as target electric energy burden, appropriate tiering structures, and the impact of electrification.

Figure 4.3: **Massachusetts Tiered Discount Rates by Household Income Level**



Source: Massachusetts DPU

California Adopts Income-Graduated Fixed Charges

In June 2022, the California Legislature passed Assembly Bill 205 (AB 205) which allows the recovery of fixed costs on residential bills to shift from volumetric rates to a separate, fixed amount. In addition, the law requires that the total costs recovered may not increase, and the fixed charge must be income graduated.

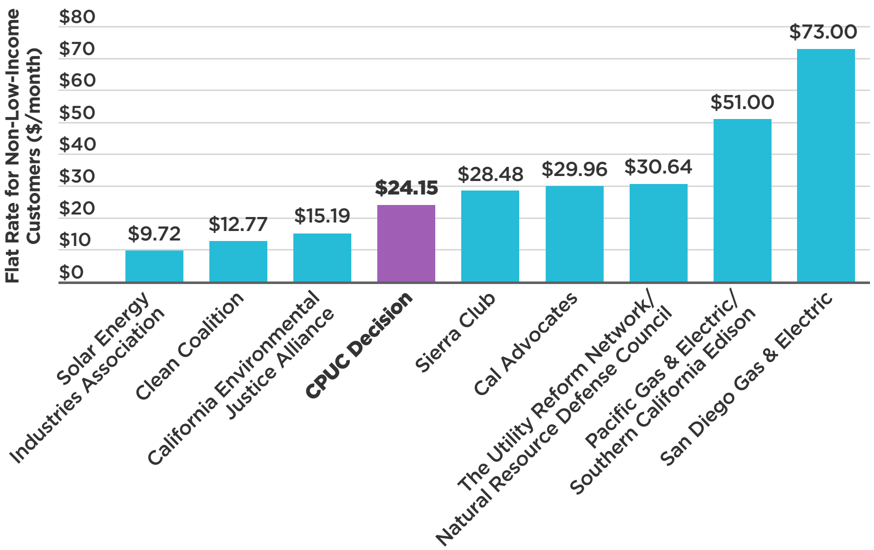
In the ensuing rulemaking, stakeholders considered multiple implementation issues. Notable issues included defining fixed charges subject to income graduation, determining the appropriate number of income tiers (AB 205 required at least three tiers), defining eligible low-income ratepayers, and establishing a process to verify income while ensuring data privacy. Stakeholders also weighed how fixed charges may impact the adoption of energy efficiency and electrification measures.

In May 2024, the California Public Utilities Commission (CPUC) unanimously adopted the following fixed charges:

- **Tier 1:** Customers enrolled in the California Alternate Rates for Energy (CARE) low-income assistance program will pay a discounted flat rate of $6 per month.
- **Tier 2:** Customers enrolled in the Family Electric Rate Assistance Program (FERA), as well as those residing in deed-restricted affordable housing with incomes at or below 80% of the area median income, will qualify for a discounted flat rate of $12 per month. Area median income is defined at the county level by the California Department of Housing and Community Development.
- **Tier 3:** All remaining customers pay $24.15 per month. This rate was on the lower end of proposals submitted by stakeholders to the CPUC (see Figure 4.4).

In addition to fixed charges, the CPUC lowered volumetric rates by 5 to 7 cents per kilowatt-hour. Southern California Edison and San Diego Gas & Electric will implement the new rates in Q4 2025, while Pacific Gas & Electric will begin implementation in Q1 2026. In addition, the CPUC approved an aggregate total of up to $35.6 million for implementation costs.

Figure 4.4: **Comparison of California Flat Electric Rate Proposals**



Source: CPUC

> This new billing structure puts us further on the path toward a decarbonized future, while enhancing affordability for low-income customers and those most impacted from climate change-driven heat events. This billing adjustment makes it cheaper across the board for customers to charge an electric vehicle or run an electric heat pump, which will spur greater uptake of these technologies that are essential to transitioning us away from fossil fuels.
>
> **Alice Reynolds**
> President, CPUC

New York Launches Energy Affordability Pilot Program

In August 2024, the New York State Public Service Commission approved the implementation of the Energy Affordability Guarantee (EAG) pilot. The program will provide approximately 1,000 households with “tailored bill assistance” to reduce electricity costs to no more than 6% of annual household income.

To be eligible for the program, customers must fully electrify their space and water heating through the EmPower+ program which provides no-cost and subsidized energy efficiency and clean energy upgrades for low- to moderate-income households. The EmPower+ program is administered by the New York State Energy Research and Development Authority (NYSERDA).

The EAG pilot program will be funded through a $50 million appropriation in the state budget. In addition, the EmPower+ program is leveraging home electrification and appliance rebates available through the Inflation Reduction Act.

Customers are expected to receive the energy guarantee for 15 years which is the estimated useful life of a heat pump. If a customer moves from a home participating in the program, the new occupant is eligible to apply for participation in the pilot.

Key Considerations in Designing Rate Solutions

As utilities explore rate design strategies to address affordability concerns, some questions to consider include:

- What rate designs will best meet energy affordability objectives (e.g., income-graduated charges, tiered discount rates, etc.)?
- How will rate designs that address energy affordability concerns interact with existing low-income offerings, such as Low-Income Home Energy Assistance Program (LIHEAP) or existing discount rates?
- How will bill discounts that address energy affordability concerns be recovered and from which customer classes?
- How will rate designs that address energy affordability concerns balance other rate design principles, such as fairness, simplicity, economic efficiency, and promotion of energy efficiency and clean technologies?
- What rate designs will help maximize enrollment among eligible customers?

Utilities, regulators, and stakeholders must carefully consider tradeoffs. In the end, ensuring equitable access to essential services while advancing broader energy policy objectives will require balancing program precision, administrative feasibility, and consumer protection.

IMPLICATIONS

Affordability remains a key concern for utilities, regulators, and stakeholders. This concern is particularly potent for low-income households which experience elevated energy burdens. Innovative rate designs can be deployed to ensure these households retain access to essential services. These programs can vary significantly, depending on jurisdiction, but must balance a host of tradeoffs.

Sources:

American Council for an Energy-Efficient Economy, Combined Energy Burdens: Estimating Total Home and Transportation Energy Burdens (May 2024); Massachusetts Department of Public Utilities Docket 23-150, Order issued by Chair Van Nostrand, Commissioner Fraser, and Commissioner Rubin (September 30, 2024); CPUC Fact Sheet, "CPUC Decision Cuts Price of Electricity Under New Billing Structure and Accelerates California's Clean Energy Transition" (May 9, 2024); Utility Dive, "California PUC Oks $24/month fixed charge for IOUs with eye to equity, electrification" (May 10, 2024); NY Governor Press Release, "Governor Hochul Announces Energy Affordability Guarantee Pilot Program for Low-Income Utility Customers" (August 15, 2024); Utility Dive, "New York encourages electrification with new grid planning process, affordability pilot" (August 19, 2024); NC Clean Energy Technology Center, "With Load Growth and Fear of Rising Utility Bills, Are Low-Income Customers Protected?" (July 29, 2024); ScottMadden research

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ARTICLE

Navigating Energy Affordability Through Innovative Rate Design

ARTICLE

Manage Through Industry Disruption with a Proven Utility Business Planning Approach

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Geothermal Energy

A familiar technology garners new interest.

KEY TAKEAWAYS

The term “next-generation geothermal” refers to new approaches that leverage tools and techniques developed in the oil and gas sector to develop enhanced geothermal systems or closed-looped systems.

The emerging industry has shown rapid technical improvements at both government and private sector demonstration sites. Fervo Energy is now building and secured offtakers for a 400 MW utility-scale commercial project.

The DOE estimates that overcoming technology and market challenges could lead to 90 GW of next-generation geothermal being deployed by 2050—a more than 20-fold increase over the 3.7 GW of conventional geothermal operating today.

New Technologies and Techniques Spur Interest and Possible Growth of Geothermal Generation

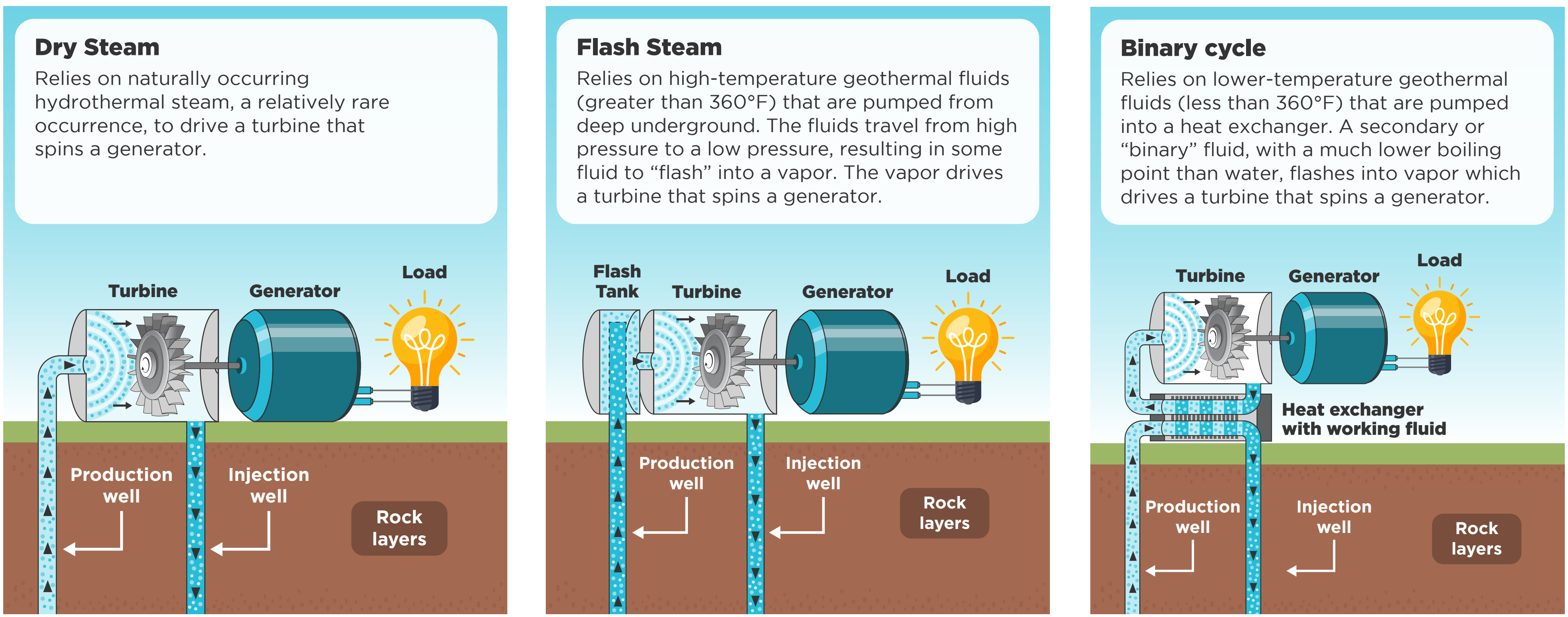
Conventional geothermal power—also known as hydrothermal—extracts thermal energy from the Earth's crust to generate electricity. This renewable resource is dependent on specific subsurface conditions. Current technologies require both sufficiently hot rocks and natural occurring fractures that allow fluid to flow through at relatively high rates (see Figure 5.1).

A key advantage of geothermal is stable output, allowing the renewable resource to provide baseload energy. However, naturally occurring geothermal resources exist in niche locations and are difficult to identify in the absence of certain geological features on surface (e.g., geyser or hot spring).

The reliance on these naturally occurring geological features constrains the development of geothermal power. There are 93 geothermal power plants—totaling 3.7 GW of capacity—located in seven states: California, Nevada, Oregon, Idaho, Utah, New Mexico, and Hawaii.

However, new technologies and techniques are spurring the development of "next-generation geothermal." If successful, next-generation geothermal could expand the available geothermal resource and add an important clean, firm renewable resource to the ongoing energy transition.

Figure 5.1: **Three Types of Geothermal Power Plant Technologies**



Source: DOE

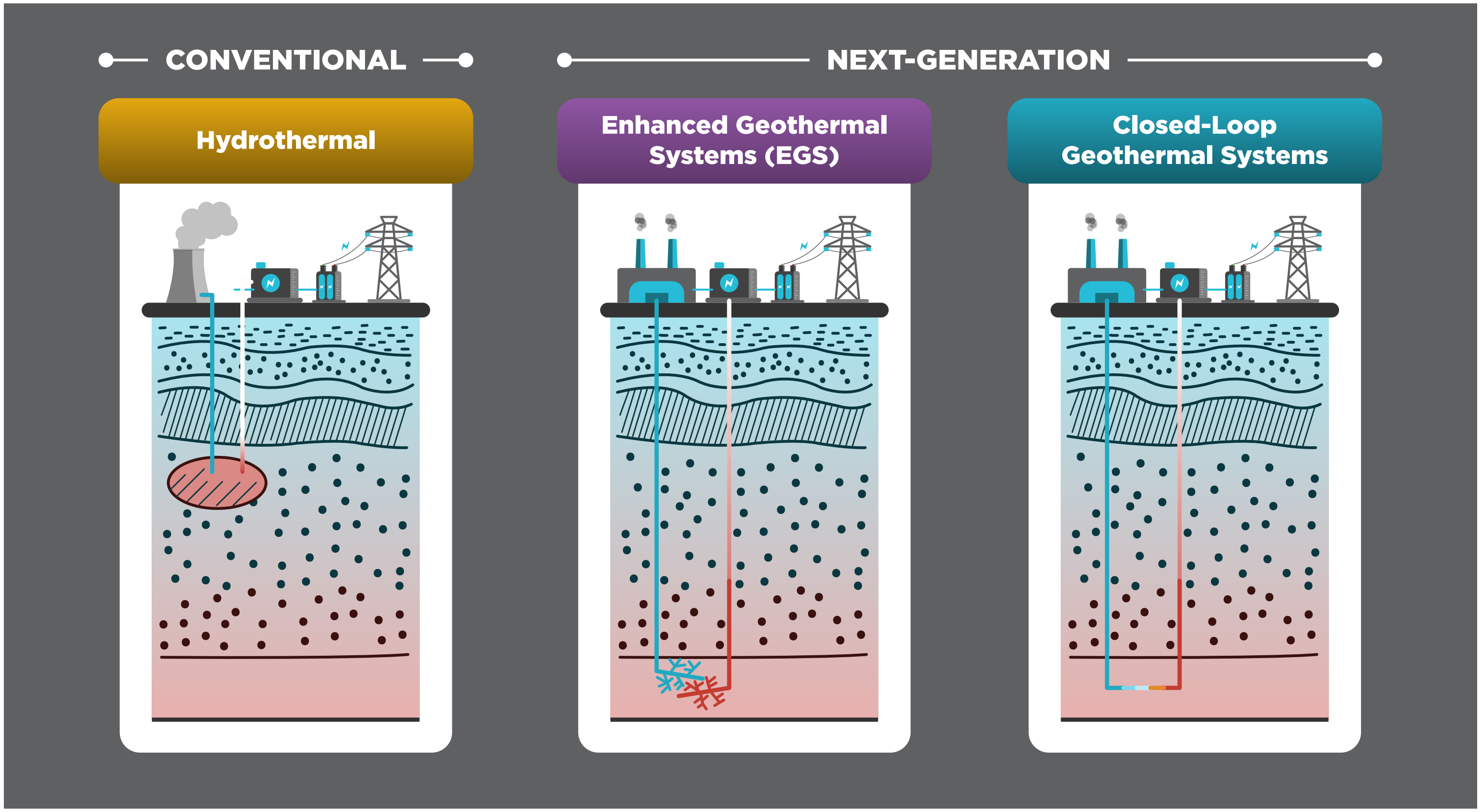
Next-Generation Geothermal Expands Resource Availability

In simple terms, next-generation geothermal uses modern technologies to create a fluid reservoir in ubiquitous hot rocks. Once heated, the fluids drive turbines to generate electricity or, in some cases, provide district heating (i.e., distributing heat through a series of insulated pipes to multiple residential or commercial buildings).

Two types of next-generation geothermal technologies are under development: **enhanced geothermal systems (EGS)** and **closed-loop systems** (see Figure 5.2).

- EGS use commercial bidirectional drilling and hydraulic fracturing to pump fluids through an artificial reservoir.
- Closed-loop systems or "advanced geothermal systems" consist of large, artificial, closed-loop circuits in which a working fluid is circulated and heated by subsurface rocks through conductive heat transfer.

Figure 5.2: **Comparison of Conventional and Next-Generation Geothermal Technologies**



Source: DOE

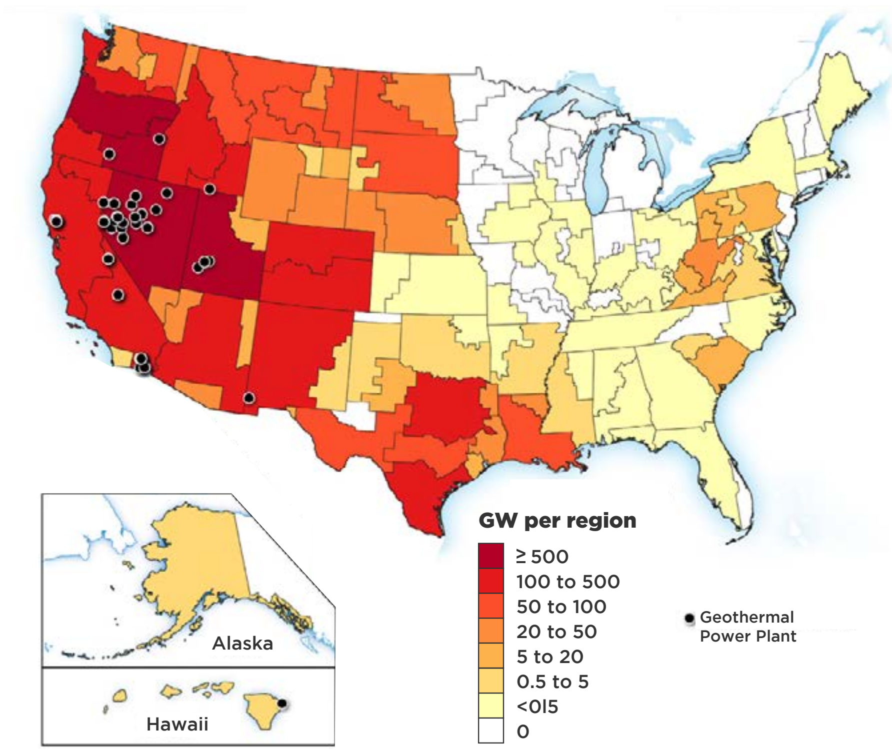
Next-Generation Geothermal Expands Resource Availability (Cont.)

Based on DOE estimates, next-generation geothermal technologies expand the technical resource potential in the United States from 40 GW to 5,000 GW (see Figure 5.3). Technical resource potential considers system performance, topographic, environmental, and land-use constraints but does not consider economics.

With greater resource availability, the DOE estimates 90 GW of next-generation geothermal could be deployed by 2050. Under certain market conditions, such as limited land available for other renewables, deployments could reach 300 GW.

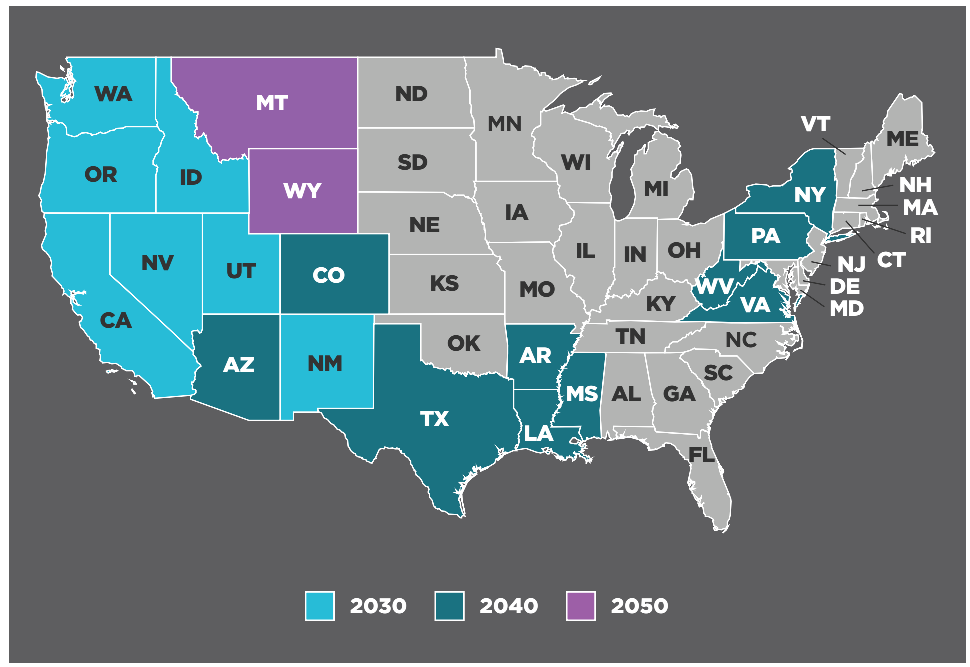
While much of the resource would remain concentrated in western states due to underlying geography, there could be deployment opportunities in midwestern and eastern U.S. states over time (see Figure 5.4).

Figure 5.3: **Next-Generation Geothermal Resource Estimates**



Source: DOE

Figure 5.4: **Potential Geographic Extent of Next-Generation Geothermal Deployment Over Time**



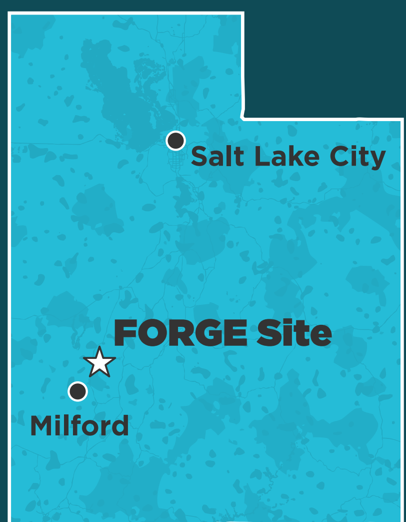
Source: DOE

DOE Investments Have Been Critical in Fostering Technology Development

Beginning in 2014, the DOE began researching how oil and gas techniques could be used for next-generation geothermal. The effort resulted in the establishment of the Utah Frontier Observatory for Research in Geothermal Energy (FORGE) in 2018.

Utah FORGE functions as a field laboratory to demonstrate the viability of next-generation geothermal technologies. In particular, it allows tools and techniques to be developed and tested at higher working temperatures than what is typically found in oil and gas operations.

The research conducted at Utah FORGE has spanned innovative drilling techniques, reservoir stimulation technologies (i.e., enhancing a reservoir to increase its energy productivity), and well connectivity and flow testing.



Fervo Energy Building Commercial Facility

With a focus on EGS technologies, Fervo Energy may be the most prominent geothermal start-up company. Notable accomplishments include a successful pilot project and the start of drilling at a utility-scale commercial project.

In 2021, Fervo Energy signed an agreement with Google to develop next-generation geothermal. In 2023, the company began supplying power to Google data centers from the 3.5 MW Project Red facility in Nevada.

The company has since moved to drilling wells at the 400 MW Cape Station in Utah. As of July 2024, the company had contracted 320 MW of power to Southern California Edison and 53 MW of power to California community choice aggregators.

Beyond Fervo Energy, multiple geothermal start-up companies have recently raised funding to deploy demonstration projects, including closed-loop projects (see Figure 5.5).

Figure 5.5: **Selected Start-up Companies Developing Next-Generation Geothermal**

Key Players	Description and Recent Developments
Eavor Technologies	▪ Developing a closed-loop geothermal technology capable of generating electricity and providing district heating ▪ Projects include a pilot loop completed in Alberta, Canda, a deep-drilling demonstration in New Mexico, and a large-scale demonstration (8 MW) under development in Germany ▪ Raised C$182 million (~U.S.$132 million) in Series B funding in October 2023. Funding includes C$90 million (~U.S.$65 million) from the Canada Growth Fund, a federal program supporting low-carbon initiatives
Zanskar	▪ Developing AI software to improve geothermal discovery and development process ▪ Claims their field data collection program collects more early-stage field data every three months than all data collected by industry and academia over the previous 10 years ▪ Raised $30 million in Series B funding in May 2024. Plans to accelerate technology development and advance its portfolio of greenfield power projects. Also acquired operating geothermal power plant in New Mexico
Quasie Energy	▪ Developing a novel technique to vaporize rock with high-power microwaves, thereby allowing the company to drill deeper than traditional approaches ▪ Raised $21 million in Series A funding in March 2024. Plans to use funds to expand field operations and strengthen supply chain
Sage Geosystems	▪ Developing technology to store energy for short and long durations using pressurized water stored underground ▪ Pilot project in Texas demonstrated the ability to produce 200 kW for more than 18 hours (long-duration storage) and 1 MW for 30 minutes (load-following generation) ▪ Raised $17 million Series A funding in February 2024. The funding will go toward building a 3 MW commercial geo-pressurized geothermal system
XGS Energy	▪ Developing a proprietary material to pump into rocks that is 50 times more thermally conducive than native rock ▪ Raised $9.7 million in Series A funding in January 2024. The funding will go toward building a prototype to demonstrate the commercial readiness of their technology

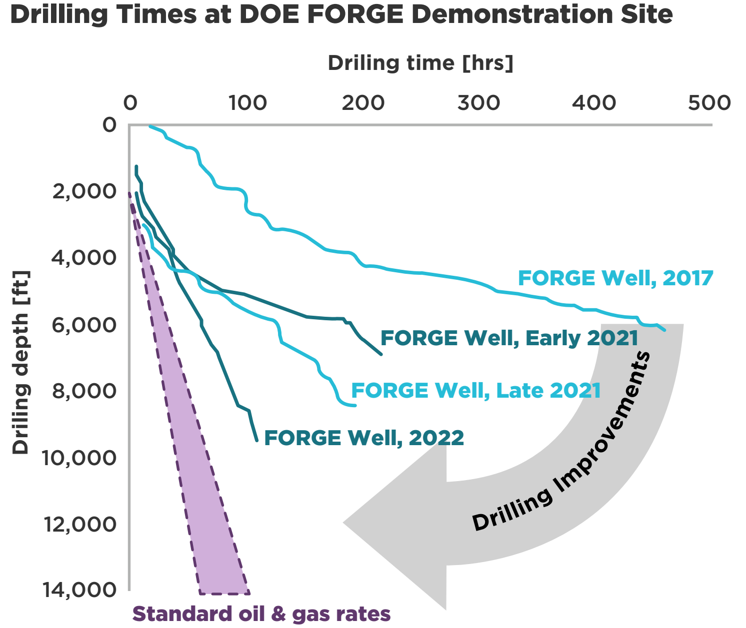
Sources: Industry news and company websites

Technology Advancements, But Challenges Remain

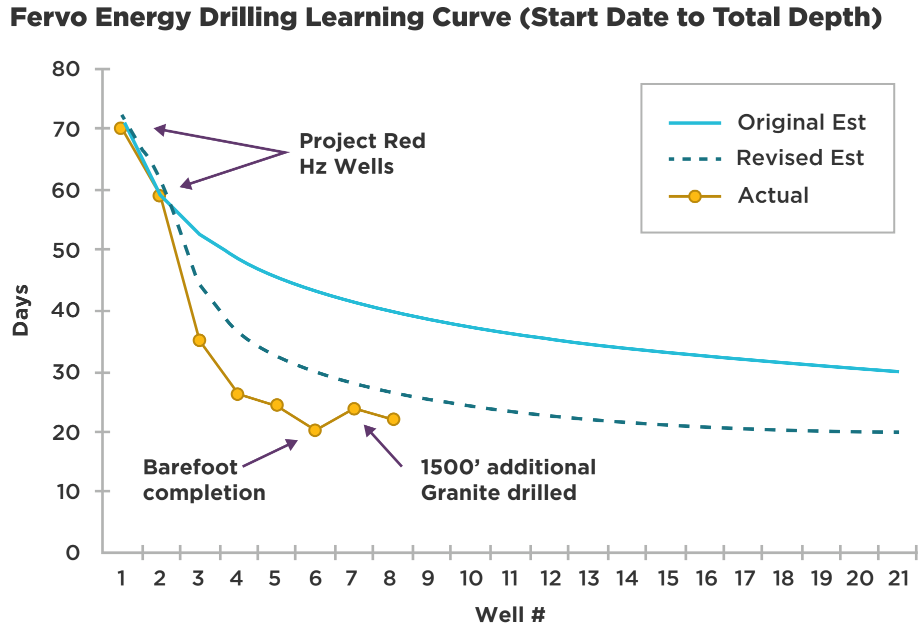
Data from public and private sector demonstrations show significant improvements in drilling times and costs (see Figure 5.6):

- Utah FORGE improved drilling speeds by more than 500% in three years, resulting in well development costs decreasing from $12 million to under $5 million per well.
- Fervo Energy demonstrated a 300% increase in drilling rate, which lowered drilling costs from $9.5 million to $4.8 million over six wells in six months.
- The DOE estimates overnight capital costs have recently declined nearly 50%—dropping from $27,800 per kW in 2021 to ~$14,700 per kW in 2023.

Figure 5.6: **Next-Generation Geothermal Learning Curves**



Source: DOE



Source: Fervo Energy

Technology Advancements, But Challenges Remain (Cont.)

Despite these advancements, next-generation geothermal must overcome multiple challenges before achieving wider deployment. In particular, the DOE highlights five distinct challenges facing the technology:

- High up-front costs
- Perceived and actual operability risks for deployment
- Long and unpredictable development life cycles
- Existing business models
- Community opposition

Addressing these challenges will require multiple solutions, which may range from power purchase agreements that value clean, firm power to enhanced business models that provide heat to offtakers (see Figure 5.7).

The solutions outlined by the DOE align with the "Enhanced Geothermal Shot," an effort to reduce the cost of EGS by 90% to $45/MWh by 2035.

Figure 5.7: **Technology Challenges and Potential Solutions**

Challenges	Potential Solutions
High up-front costs and risks constraining development capital and limiting geographic reach	▪ About $5 billion in capital to finance the validation suite of first-of-a-kind developments in varied geologies ▪ Market signals, such as high-valued power purchase agreements, to motivate investment in initial deployments ▪ In-field testing and innovation at active geothermal developments through R&D spending ▪ New financial products to reduce drilling costs such as public/private cost-share agreements and drilling insurance programs
Perceived and actual operability risk for deployments	▪ Strategic demonstration siting and data dissemination from more than 10 early deployments to show sustained power production
Long and unpredictable development life cycles driven by permitting and interconnection	▪ Allowing for combining and streamlining of specific steps in permitting process, where authorized ▪ Technology changes that allow certain steps to occur in tandem ▪ Centralization of geothermal-specific permitting expertise, where authorized
Existing business models undervaluing the potential of next-generation geothermal	▪ Planning policies that incentivize higher-cost, higher-value power ▪ Leveraging flexible geothermal operations to capture highest-value power ▪ New offtake models (e.g., subsurface developers providing heat for multiple purposes)
Community opposition in some instances	▪ Adherence to long-established, induced seismicity and environmental monitoring best practices ▪ Early, frequent, and transparent communication

Source: DOE

IMPLICATIONS

Conventional geothermal power is constrained to naturally occurring geological features. Next-generation geothermal technologies could vastly expand the availability of geothermal for power generation in the United States.

A major appeal of next-generation geothermal power is the ability to provide clean, firm renewable energy. Government-funded R&D and start-up companies are showing early successes, but many hurdles remain before the technology can scale more broadly. Over the long term, next-generation geothermal could play an important role in the energy transition.

Sources:

U.S. Department of Energy, Pathways to Commercial Liftoff: Next-Generation Geothermal Power (March 2024); U.S. Department of Energy, Enhanced Geothermal Shot (August 2023); Congressional Research Service, Enhanced Geothermal Systems: Frequently Asked Questions (June 2024); International Renewable Energy Agency, Global Geothermal Market and Technology Assessment (2023); National Renewable Energy Laboratory, Enhanced Geothermal Shot Analysis for the Geothermal Technologies Office (January 2023); Latitude Media, "Geothermal startups are suddenly raising a lot of money" (May 2024); Utility Dive, "Sage Geosystems raises $17M to build first-of-its-kind geothermal energy storage system in Texas" (February 2024); Kareem El-Sadie et al., "Review of Drilling Performance: In A Horizontal EGS Development," Proceedings of the 49th Workshop on Geothermal Reservoir Engineering (February 2024); *Power* Magazine, "Delving Deeper: New Optimism for Enhanced Geothermal Systems" (April 2024)

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THE ENERGY INDUSTRY
IN CHARTS

Looking at Clean Energy Investment and Federal Demonstration Project Funding

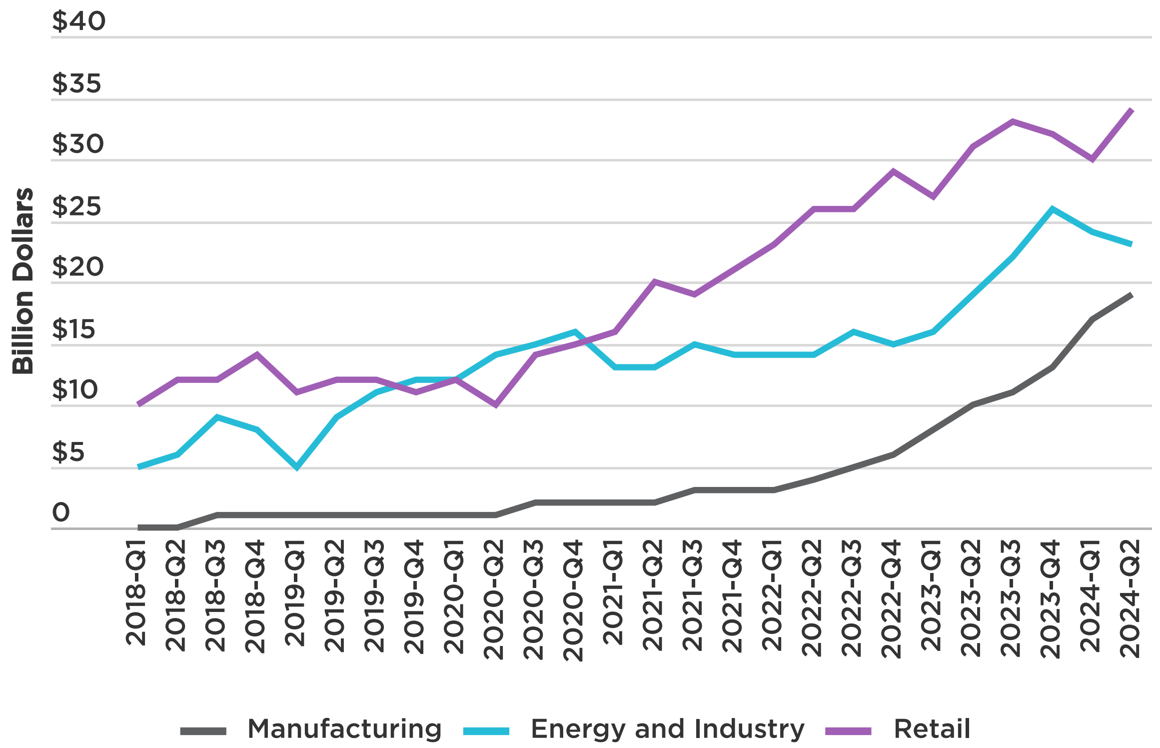
In the two years following the passage of the Inflation Reduction Act, businesses and consumers invested $493 billion in clean energy technologies and infrastructure—a 71% increase from the two-year period preceding passage of the law.

Clean energy investments can be organized into the following categories:

- **Manufacturing:** Investment in the construction or expansion of factories that manufacture clean energy, clean vehicle, building electrification, or carbon management technology.
- **Energy and Industry:** Investment in new or existing facilities to produce clean energy, capture carbon dioxide emissions, or decarbonize industrial activity.
- **Retail:** Investment by individual households and businesses purchasing or installing clean electricity generation and storage, clean vehicles, or building electrification technology.

Clean energy investments in all three categories have increased significantly since the passage of the Infrastructure Investment and Jobs Act (November 2021) and Inflation Reduction Act (August 2022).

Figure 6.1: **Quarterly U.S. Clean Energy Investment ($ Billions)**



Source: Rhodium Group and MIT Center for Energy and Environmental Policy Research (CEEPR)

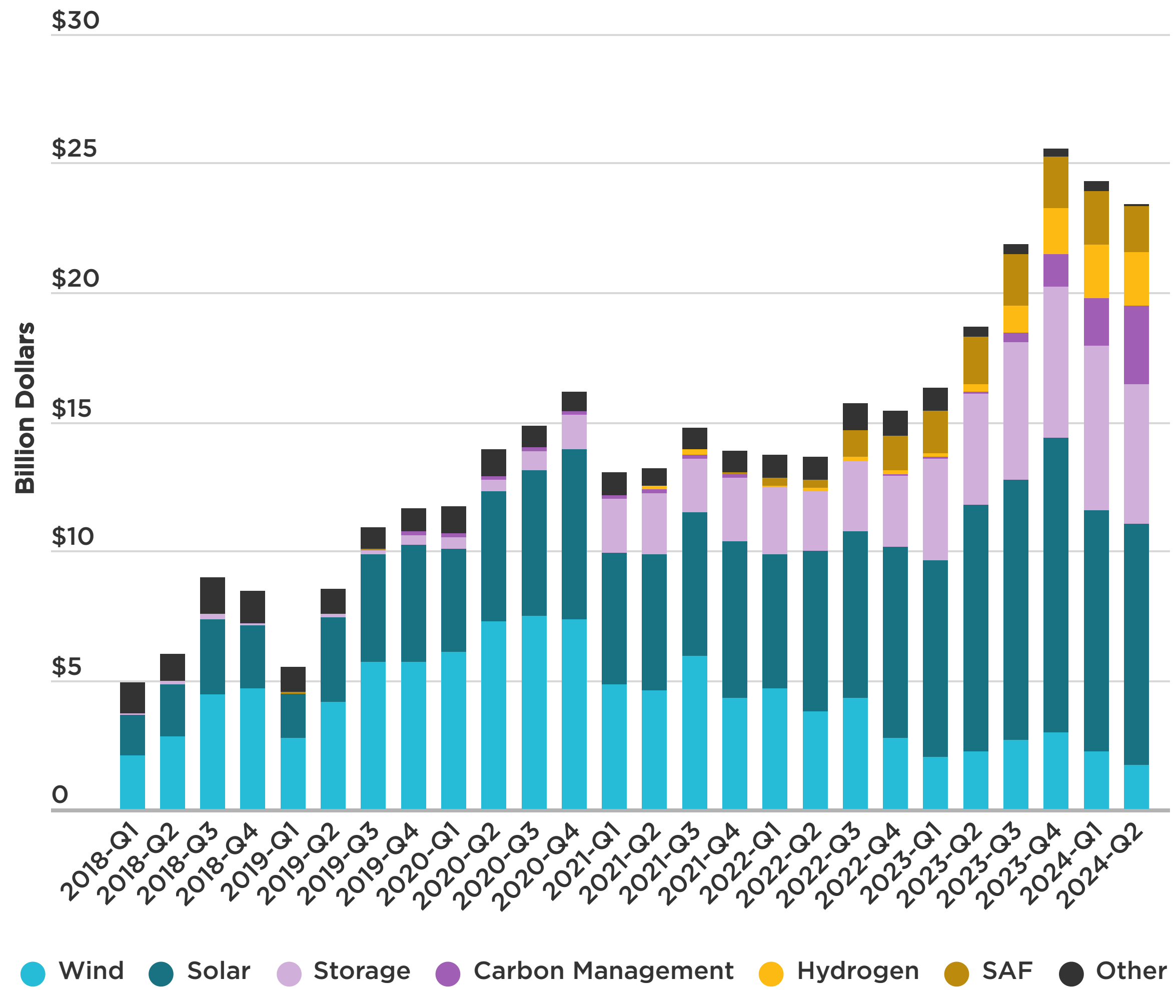
Over the last full year of data (Q3 2023 to Q2 2024), energy and industry investment exceeded $20 billion per quarter.

During the same period, the top 10 states for investment included:

- **Texas ($31 billion)**
- **California ($15.1 billion)**
- **Arizona ($5.5 billion)**
- **Louisiana ($3.9 billion)**
- **Florida ($2.9 billion)**
- **Indiana ($2.5 billion)**
- **Illinois ($2.1 billion)**
- **Nevada ($2.1 billion)**
- **Ohio ($2.1 billion)**
- **New Mexico ($1.9 billion)**

Emerging technologies receiving investments include sustainable aviation fuel (SAF), hydrogen, and carbon management.

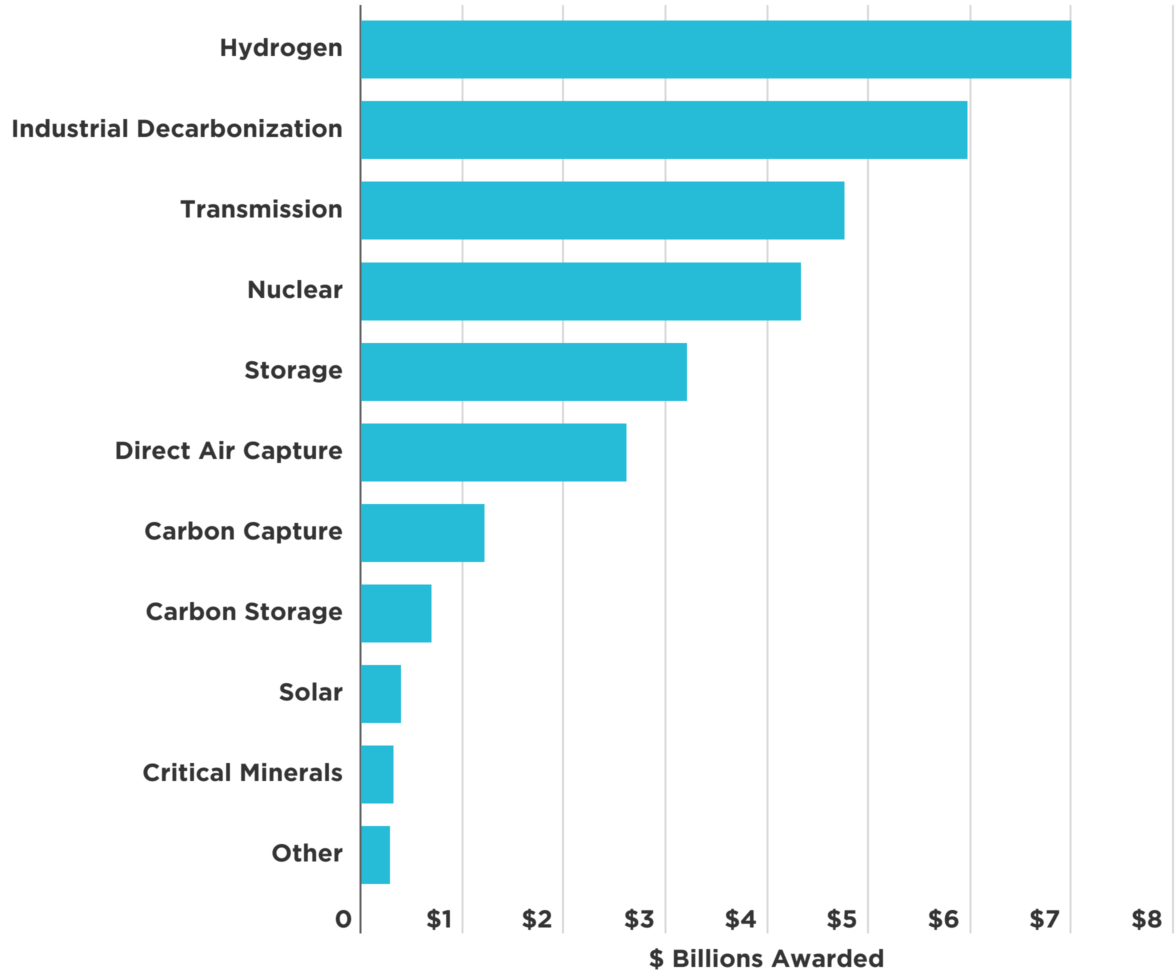
Figure 6.2: **Quarterly U.S. Energy and Industry Investment by Technology ($ Billions)**



Source: Rhodium Group and MIT Center for Energy and Environmental Policy Research (CEEPR)

- As of September 2024, the Department of Energy (DOE) has awarded $30.8 billion—or roughly half—of the $63 billion appropriated by the Energy Act of 2020 and Infrastructure Investment and Jobs Act to support competitive demonstration programs.
- Nearly three-quarters of the funding ($22.1 billion) has been directed to four technologies: hydrogen, industrial decarbonization, transmission, and nuclear.
- The largest individual programs are regional clean hydrogen hubs ($7 billion awarded), advanced nuclear reactor demonstration program ($3.2 billion awarded), and battery manufacturing and recycling grant program ($2.8 billion awarded).

Figure 6.3: **DOE Funding for Demonstration Projects ($ Billions)**



Sources: ClearPath Infrastructure Tracker; ScottMadden analysis

GLOSSARY

Ass'n
Association

B
billion

BSER
best system of emissions reduction

C$
Canadian dollars

CAGR
compound annual growth rate

capex
capital expenditure(s)

CBO
U.S. Congressional Budget Office

CC
combined cycle

CCS
carbon capture and storage

CO_2
carbon dioxide

Comm'n
Commission

CPS
New EPA GHG Emissions Standards (or Carbon Pollution Standards)

CPUC
California Public Utilities Commission

CT
combustion turbine

DOE
U.S. Department of Energy

DPU
Massachusetts Department of Public Utilities

EEI
Edison Electric Institute

EIA
U.S. Energy Information Administration

EOR
enhanced oil recovery

EPA
U.S. Environmental Protection Agency

EV
electric vehicle

F
Fahrenheit

FEED
front-end engineering and design

FERC
Federal Energy Regulatory Commission

GETs
grid-enhancing technologies

GHG
greenhouse gas

GW
gigawatt

GWh
gigawatt-hour

IIJA
Infrastructure Investment and Jobs Act

IOU
investor-owned utility

IRA
Inflation Reduction Act of 2022

IRP
integrated resource plan

ISO
independent system operator

kW
kilowatt

kWh
kilowatt-hour

lbs.
pounds

M or mil.
million

MATS
Mercury and Air Toxics Standards

MMBtu
million British thermal units

MW
megawatt

MWh
megawatt-hour

NARUC
National Ass'n of Regulatory Utility Commissioners

NERC
North American Electric Reliability Corporation

NGCC
natural gas combined cycle

NIETC
national interest electric transmission corridor

PPA
power purchase agreement

PSC
public service commission

PUC
public utility commission

RTO
regional transmission organization

RULOF
remaining useful life and other factors

ENERGY PRACTICE
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