U.S. Hydrogen Infrastructure Action Plan

How Much, How Fast?

Infrastructure Requirements of EPA's Proposed Power Plant Rules

EFI FOUNDATION

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Executive Summary

The U.S. Environmental Protection Agency (EPA) is proposing to use its Clean Air Act authorities to set carbon dioxide limits for new gas-fired generators, existing coal units, and certain existing gas-fired generation facilities. This report, part of a series called U.S. Hydrogen Infrastructure Action Plan, evaluates the systemwide impacts of EPA's proposal, especially in terms of the scale, timing, and feasibility of potential infrastructure requirements.

EPA's proposal reflects the need for aggressive power sector decarbonization

In the United States and many other heavily industrialized countries, the electric grid is the linchpin for economywide decarbonization. Shifting to a zero-carbon electricity system could directly reduce one-quarter of U.S. carbon dioxide (CO_2) emissions today and enable additional reductions through increased end-use electrification in buildings, transportation, and other sectors. This led the Biden administration to set a target of 100% carbon pollution-free electricity by 2035 and is driving utilities that now cover nearly 80% of U.S. customers to set midcentury 100% carbon reduction targets.[1]

In May 2023, EPA proposed new emissions limits for fossil fuel-fired generators to align the sector's decarbonization trajectory more closely with the administration's goals. As part of its Clean Air Act (CAA) authorities, EPA is proposing that all existing coal plants and large natural gas generators adopt new technology-based requirements starting in 2030 and 2032, respectively. All new fossil generation, except for gas "peaking" units that operate relatively infrequently, that is, at less than 20% capacity factor, is also subject to these rules.

EPA's proposal includes highly efficient generation, co-firing clean hydrogen (H_2) with natural gas, and carbon capture and storage (CCS) as the low-carbon technologies for compliance, also called "best system of emission reduction" (BSER).

Generally, the proposal requires larger units—300 megawatts (MW) or larger—that run more frequently—50% capacity factor (CF)[a] or higher—to adopt more stringent standards than other plants. EPA determines what classifies as BSER, reflecting technical and economic realities and any non-air-quality health and environmental impacts and energy requirements.[2] According to EPA's Regulatory Impact Analysis (RIA), this proposal would

[a] The capacity factor measures how often a power plant operates for a given period of time. It is calculated by dividing the actual electricity output by the maximum possible output the plant could produce.

reduce U.S. power sector emissions by more than 40 million metric tons (Mt) per year from 2028 to 2042.[3,b] The power sector emitted roughly 1,500 Mt in 2022.

The Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA) offer a range of financial incentives across the CCS and clean hydrogen value chains. The IRA—the largest investment in clean energy in U.S. history—also directs EPA to consider the IRA's benefits (e.g., technology-specific tax credits) when determining BSER and other aspects of its authority under Section 111 of the CAA. These policies are appropriately driving high expectations for CCS and clean hydrogen.

The U.S. Department of Energy's *U.S. National Clean Hydrogen Strategy and Roadmap* sees strategic annual demand for clean hydrogen reaching 50 Mt by 2050.[4] DOE's *Pathways to Liftoff: Carbon Management* report suggests that meeting the United States' midcentury emissions reduction targets will require capturing and storing 400 Mt to 1,800 Mt of CO_2 annually.[5]

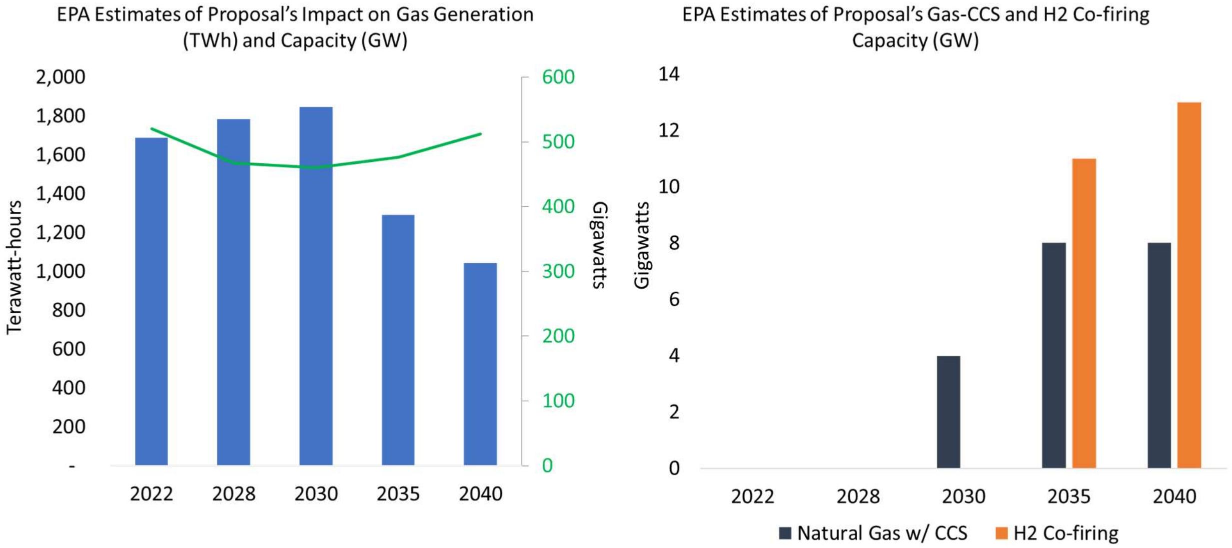
EPA's proposal addresses the scale of the challenge of reaching a carbon-free electric grid before midcentury, but it does not go as far as the Biden administration's goal of 100% carbon-free electricity by 2035. In addition to reflecting the difficult realities of reaching net-zero emissions, the proposal underscores the need for CO_2 removal and negative emissions technologies.

EPA's RIA projects a major shift away from coal in the power sector, including retirement of nearly 200 gigawatts (GW) by 2035, and a long-term strategic role for natural gas as a firming resource. U.S. power sector emissions are down roughly 40% since 2005, led by a shift from coal to natural gas and renewable energy sources.[6] EPA's proposal would accelerate these trends by targeting certain types of unabated fossil fuel-fired generation. EPA projects that its policy will increase gas-fired generation through 2030 (before falling by 2040) and expand gas generation capacity by 2040 (Figure ES 1).[7] EPA also sees modest increases in gas-fired generation with CCS (8 GW by 2040) and co-firing hydrogen with natural gas (13 GW total by 2040).

[b] In July 2023, EPA issued updated modeling results with 9,419 Mt of cumulative emission reduction through 2042 (https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0237). Because the update did not include the full suite of modeling assumptions, the RIA analysis was used for reference in this report.

Figure ES 1.

EPA's estimates of select impacts of proposed power plant rules



Under the proposed power plant rules, EPA estimates natural gas generation will reach a peak in 2030, decreasing from then until 2040. Natural gas capacity is expected to initially fall and then expand in this time frame (left). The capacity of natural gas power plants with CCS and with hydrogen co-firing is expected to increase starting in 2030 (right). Source: See first figure mention in text for sources.

EPA's proposal creates challenging time frames for scaling new clean energy resources

EPA's proposal includes various time and resource requirements for generators depending on their size and how frequently they run during the year. For example, a large coal unit can adopt CCS by 2030 and co-fire with 40% natural gas if it plans to cease operations by 2040, or it can choose to shut down by 2035. A large existing gas generator can co-fire with hydrogen at 30% by volume in 2032, increasing to 96% by 2038, or choose to use CCS at 90% capture by 2035. Facilities can choose from these pathways, leading to facility-by-facility decisions that can impact how much new generation and capacity must be seamlessly backfilled on the system, creating uncertainty in the near term.

EFI Foundation analyzed the possible infrastructure requirements of EPA's proposal using the SESAME[c] modeling platform. Given that EPA's proposal will require certain generators to co-fire with hydrogen, adopt CCS, or reduce operations below 50% CF, modeling scenarios were developed representing these potential outcomes: 1) high hydrogen demand ("High H2"), 2) high CO_2 capture deployment ("High CCS"), and 3) high reduced operations ("High RO").

[c] SESAME stands for Sustainable Energy System Analysis Modeling Environment. https://sesame.mit.edu/

The *Reference Case* in the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook 2023* was used as a modeling baseline, and the nine EIA electricity regions were used as geographic areas of analysis.[8]

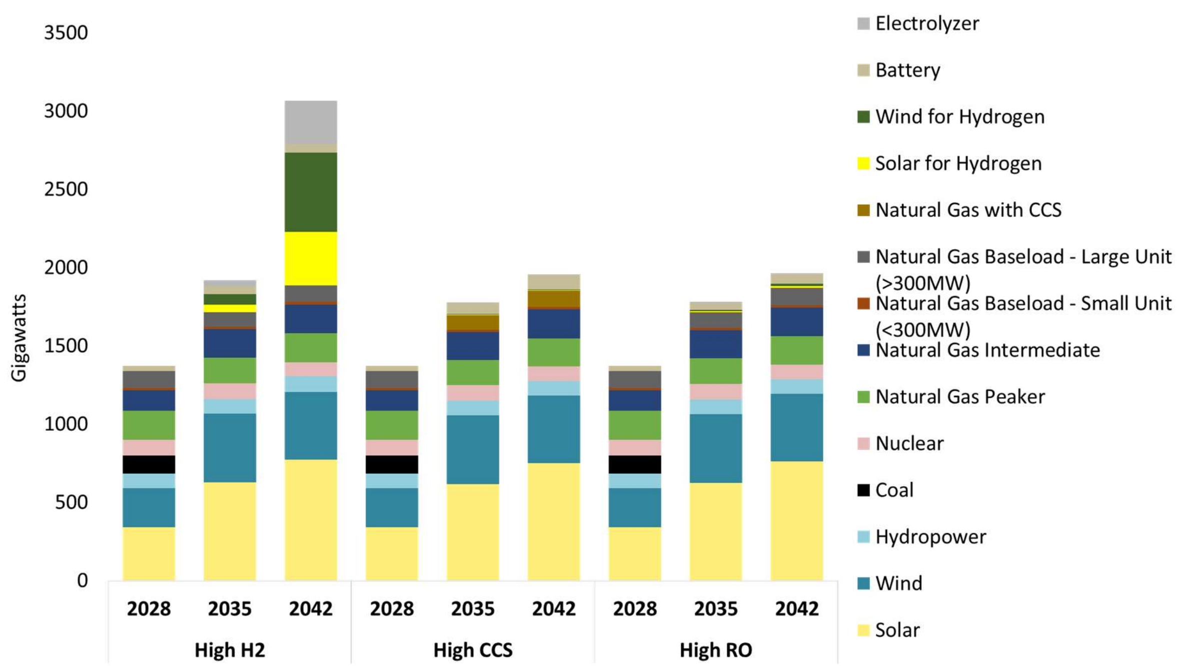
Across all three scenarios, major infrastructure deployments are needed in the next decade that may limit implementation, especially because of the highly decentralized nature of fossil generators and the regional electricity structures (Figure ES 5).

EFI Foundation modeling finds that unabated coal would phase out by 2035, as adopting CCS on existing coal by 2030—per the proposal—faces major financial and permitting headwinds. Roughly a fivefold increase in solar, a threefold increase in wind capacity, and a sixfold increase in battery storage are needed by 2035 compared to today (Figure ES 2).

The modeling also shows important differences between scenarios. For example, in the High H2 scenario, **850 GWs of dedicated renewable energy is needed by 2042 to produce the hydrogen at the life cycle emissions limit proposed by EPA, 0.45 kilograms (kg) CO_2e per kg H_2**. Reaching this scale of renewables deployment for hydrogen takes more than the current rate that renewables are added to the grid: 29 GW of solar and 6 GW of wind were added in 2023.[9] Hydrogen demand is 4 million metric tons per year, or annum (MTPA), in 2035 and 32 MTPA by 2042. There is 105 GW of gas-fired capacity that co-fires 30% hydrogen by volume in 2035 and 307 GW that co-fires 96% hydrogen by 2038. The system needs 37 GW of electrolyzers by 2035 and 275 GW by 2042. The installed gas capacity remains roughly flat through 2042.

Figure ES 2.

EFI Foundation modeling of capacity by technology and year, all scenarios



Technology capacity varies by year depending on the scenario under analysis. Coal is phased out by 2035, while solar and wind increase participation in electricity generation, including to produce clean hydrogen in the High H2 scenario. Natural gas with CCS starts to contribute to capacity by mid-2030 in both the High CCS and High RO scenarios, reaching higher values in the High CCS scenario. Source: EFI Foundation modeling analysis using SESAME tool.

In the High CCS scenario, 94 GW of gas-fired generation adopts CCS by 2035 and 105 GW by 2042, resulting in 150 MTPA of CO_2 captured in 2035 and 170 MTPA by 2042. Roughly 8 GW of dedicated renewables for hydrogen production are needed for the intermediate load units covered by the policy.

In the High RO scenario, around 80 terawatt-hours (TWh) of generation is reduced as large plants lower their CF to 49% (below the 50% threshold). All intermediate units increase generation to 49%, partially covering this gap, and 50 GW of capacity of new smaller gas units come on line.

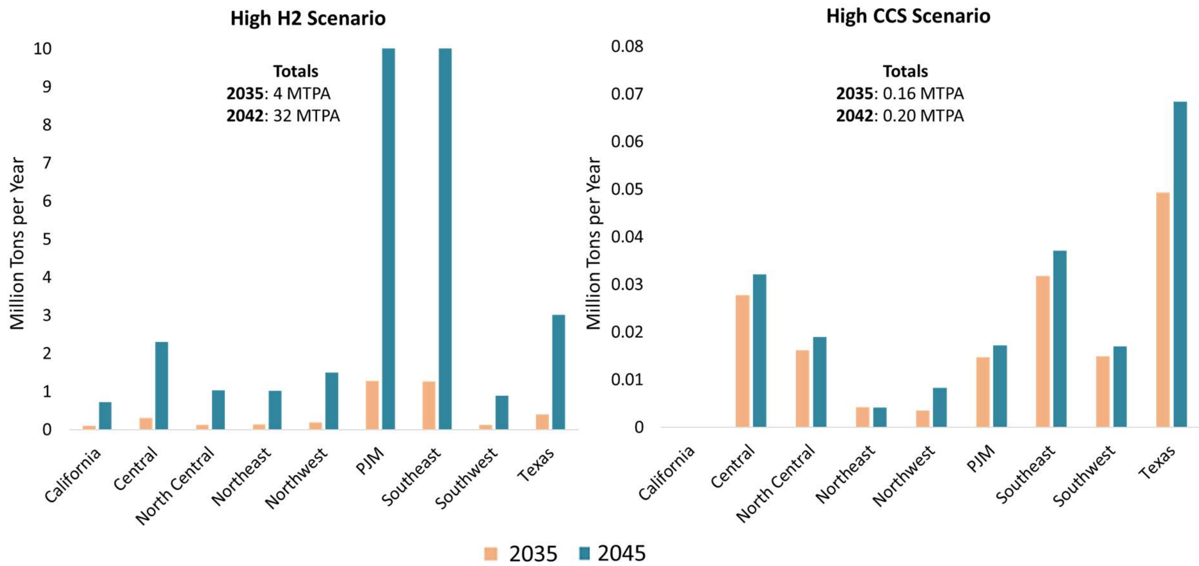
This policy disproportionately impacts regions with existing coal and large gas-fired capacity. Meanwhile, the proposed BSERs are resource dependent and not equally available across the country; some regions have abundant low-cost clean energy resources for hydrogen production and geologic storage potential, while others have neither.

This leads to considerable regional variation in terms of associated costs and compliance options. For example, capital expenditures (CAPEX) can be as high as $18 billion per year for some regions (PJM[d] and the Southeast) or as low as $1.5 billion (Northeast) depending on the modeling scenario. Figure ES 3 shows the possible regional demand for hydrogen and the amount of CO_2 capture needed in EFI Foundation's High H2 and High CCS scenarios, respectively, and highlights wide regional variation. The nine EIA zones (a combination of North American Electric Reliability Corporation and independent system operator regions) were used for this analysis.

[d] See Figure 12 for a definition of regions.

Figure ES 3.

Comparing regional hydrogen demand in 2035 and 2045 in High H2 and High CCS scenarios

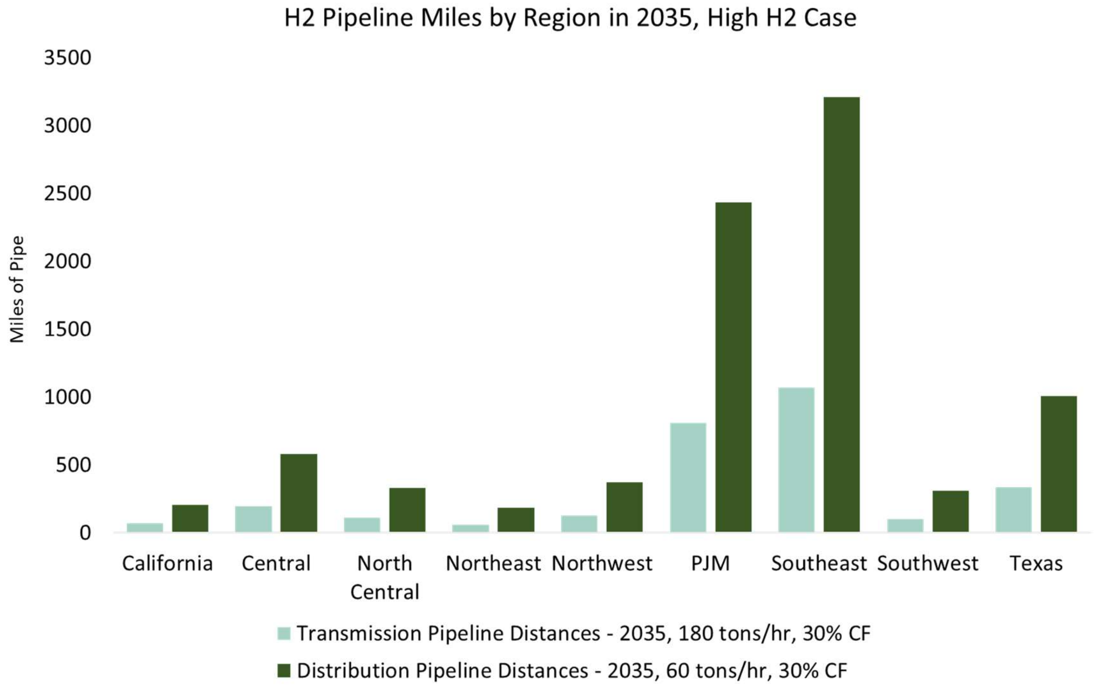


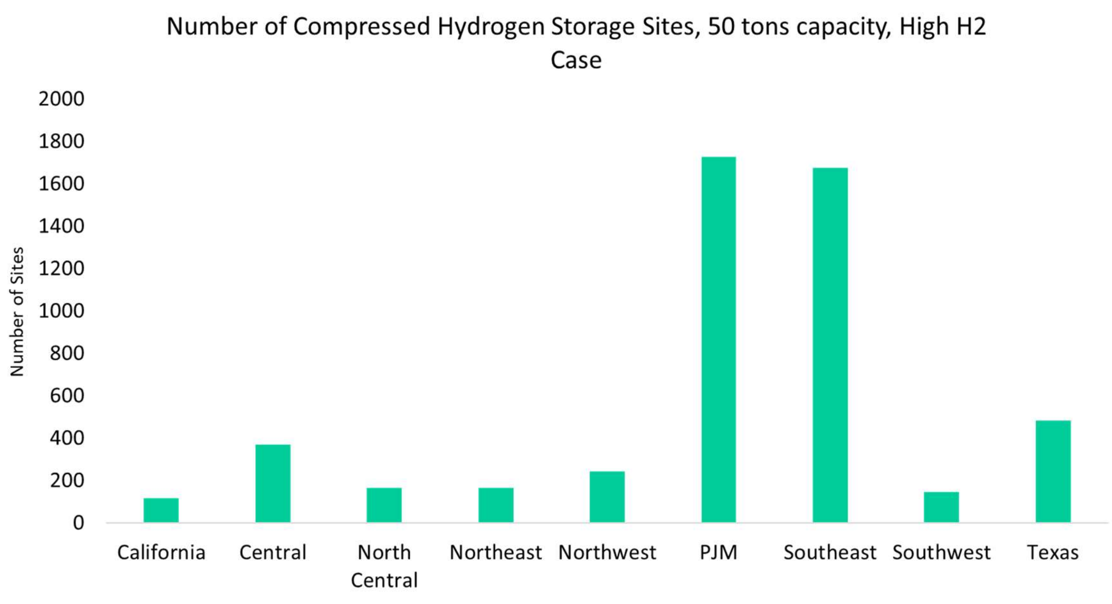
Regional variation is also observed by scenarios. Hydrogen demand is higher in the Southeast, PJM, and Texas, especially by 2042. In the High CCS scenario, hydrogen demand needs still vary by region. Source: EFI Foundation modeling analysis using SESAME tool.

To understand the systemwide impacts of EPA's proposal, EFI Foundation analyzed the infrastructure requirements of each scenario. In the High H2 scenario, for example, **more than 11,000 miles of new hydrogen pipelines (transmission and distribution) and more than 5,000 compressed hydrogen storage sites (50 tons capacity each) will be needed by 2035 (Figure ES 4)**. For context, there are around 1,600 miles of hydrogen pipelines in operation in the United States today. By 2042, nearly 95,000 miles of hydrogen pipeline is needed to accommodate the policy's shift to 96% hydrogen co-firing with natural gas.

Figure ES 4.

Infrastructure requirements in EFI Foundation's High H2 scenario by 2035





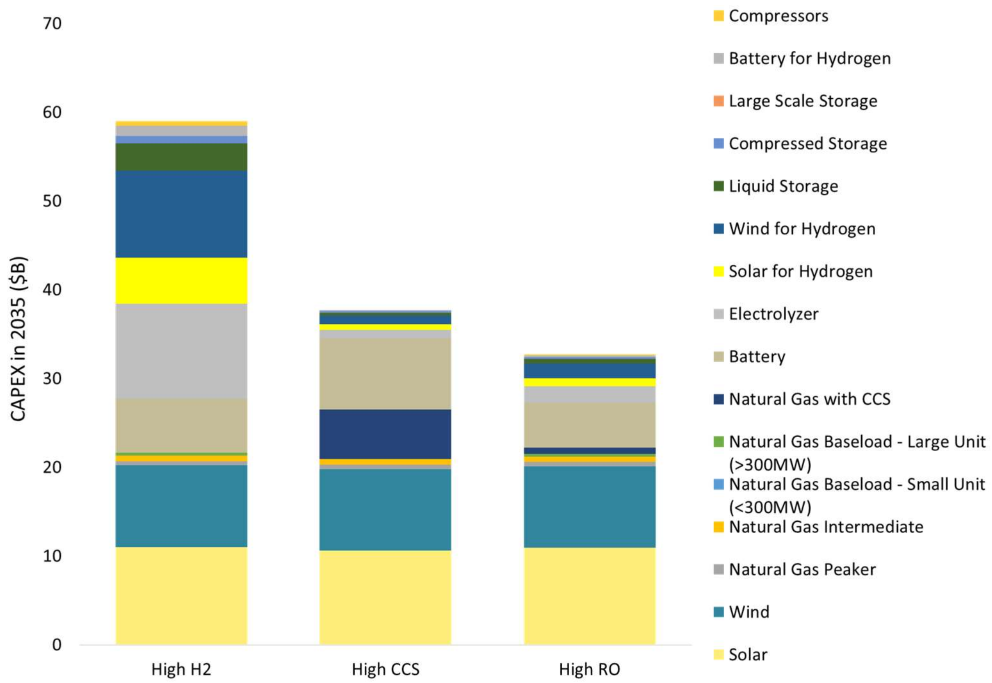
In the High H2 scenario, new infrastructure must be built to accommodate increased hydrogen needs—such as transmission pipelines carrying 180 tons of hydrogen per hour at 30% capacity factor; distribution pipelines carrying 60 tons of hydrogen per hour at 30% capacity factor; and compressed hydrogen storage sites. Infrastructure needs vary widely by region: The Southeast, PJM, and Texas are among the regions with higher infrastructure needs. Source: EFI Foundation modeling analysis using SESAME tool.

Contributing to implementation challenges is the lack of commercial CCS and clean hydrogen projects today. While various aspects of both technologies are commercially available, there are no examples of the full value chains of CCS or clean hydrogen financed, built, and operating in U.S. energy markets. This contributes to first-of-a-kind (FOAK) issues, such as unique engineering challenges and regulatory uncertainty, adding to investment risk for at-scale deployment in the next decade. **EFI Foundation FOAK costs for CCS for gas generators may be up to 40% higher than EPA's estimates, while average U.S. delivered hydrogen costs could be up to 20 times higher.**

According to EFI Foundation modeling, the capital expenditures needed to meet EPA's proposal are intrinsically tied to broader decarbonization deployments. Absent this policy, there will still need to be gigawatt-scale deployments of new wind and solar to reach net-zero emissions. EFI Foundation modeling scenarios show CAPEX requirements between $32 billion and $60 billion per year by 2035, with large regional variation (Figure ES 5).

Figure ES 5.

Capital expenditures in 2035 across EFI Foundation modeling scenarios



Capital expenditures across modeling scenarios depend on the decarbonization pathway. Higher CAPEX is expected in the High H2 case due to increased investment needs in clean hydrogen infrastructure. Costs shown are for 2035 only. Source: EFI Foundation modeling analysis using SESAME tool.

Achieving this level of deployment depends on complementary permitting reform for electricity, hydrogen, and CO_2 systems, enabled by a large workforce and extensive supply chains. While IIJA and IRA incentives offer game-changing support for these technologies, neither policy adequately addresses the permitting reform needed to scale CCS and clean hydrogen infrastructure in the proposal's time frames. The White House and Congress have issued multiple proposals for energy permitting reform since the passage of the IRA to help fill this gap. Due to the cross-jurisdictional nature of electric power, CCS, and hydrogen projects, these reforms will need to greatly improve coordination among firms, sectors, and governments.

Opportunities to advance CCS and clean hydrogen deployment

EPA's current proposal faces major implementation challenges, considering the amount of infrastructure that could be needed in the next decade to support potentially hundreds of new and existing generators throughout the country. While this proposal addresses the scale of the challenge of reaching a carbon-free electric grid before midcentury, it does not go as far as the Biden administration's goal of 100% carbon-free electricity by 2035. The agency should consider ways to add flexibility and more regionality to its approaches to ensure large-scale decarbonization efforts are deployed moving forward.

The following are three examples of how EPA and other relevant federal and state agencies can support CCS and clean hydrogen in electric sector decarbonization:

- **Align new federal policies advancing CCS and clean hydrogen deployment to the IRA**. The IRA directed tens of billions of dollars into new and expanded incentives for CCS and clean hydrogen production and extended the construction window for eligibility of the 45Q tax credit for carbon sequestration to January 1, 2033. EPA's proposal requires coal-fired units that plan to operate beyond 2039 to place carbon capture into service by 2030, two years ahead of the 45Q credit deadline to begin construction. Aligning EPA with the existing 45Q policy requirements could improve investor confidence regarding the timing of developing and permitting CCS projects. These and related CCS financing issues are addressed in the EFI Foundation's *Energy Finance Forum (EF^3)* analysis.[10] EPA could adopt the IRA's definition of clean hydrogen. Cost-effectively reaching very low life cycle emissions is one of the biggest challenges for clean hydrogen projects. This is why the IRA created flexibility for accessing the 45V tax credit for hydrogen production with a life cycle assessment (LCA) of less than 4.0 kg CO_2e/kg H_2. EPA's proposal, however, defines "clean" as an LCA of 0.45 kg CO_2e/kg H_2, significantly impacting the cost, type, scale, and regional diversity of eligible projects. For example, EFI Foundation modeling finds the delivered cost of hydrogen in the Carolinas under EPA's proposal is around \$8/kg in 2035, compared to EPA's estimate of \$0.5/kg.[11] As previously mentioned, in a High H2 scenario, this policy could require 115 GW of new wind and solar projects by 2035 dedicated only to clean hydrogen production.

- **Develop clear compliance metrics, with maximum regional flexibility, for new decarbonization proposals.** EPA's proposed BSER may lack sufficient regional flexibility to reach compliance in the proposed time frames, while managing costs and reliability. Areas of the country without abundant, low-cost renewables, access to low-cost CO_2 storage, or other alternatives (e.g., existing nuclear) may see measurably higher costs when implementing EPA's proposal compared with other regions. The CAA currently supports regional approaches through a state planning process, allowing regional entities to propose optimal systems of emissions reduction for their own jurisdictions that must achieve the necessary environmental performance outlined by EPA's proposal. These State Plans cover only existing generators—Section 111(d) of the CAA—and not new builds—Section 111(b).

  Once the EPA issues its emission standards, including BSER for specific power plant types, EPA is proposing that states have 24 months to submit their own plans to EPA that are at least as stringent in terms of emission reductions as EPA's guidelines. EPA should encourage the use of State Plans, offering robust federal-state collaboration and clear metrics for how each State Plan can reach compliance (e.g., offering guidance on what qualifies as achieving the state equivalent of total emission reductions, aligned to EPA's proposal). EPA should be explicit about how each state can reach compliance. For example, EPA could clarify that emission trading regimes and technology emission performance "averaging" can be used in State Plans. EPA could also explicitly allow legislated state policies (e.g., Regional Greenhouse Gas Initiative[e]) for electricity decarbonization that meet or exceed the performance of EPA's proposal, creating a more synchronous federal and state policy environment. EPA should also consider developing a similar approach to State Plans that cover new generating units. This could help create more system-wide visibility into how each state and region is approaching electric sector decarbonization. Furthermore, EPA's proposal lacks clear community engagement guidelines, beyond best practices. Offering clear guidelines, starting with an approach like DOE's Stakeholder Engagement Plan, and directions for ensuring community involvement with future policies is critical.[12]

[e] The Regional Greenhouse Gas Initiative is a cooperative effort among 12 states: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia – to reduce greenhouse gas emissions. https://www.rggi.org/

- **Create permitting reforms for rapid scaling of electricity, CO_2, and hydrogen infrastructure**. EPA's proposed rules do not fully consider the risks of permitting delays, which can be considerable when deploying FOAK technologies. Improving the permitting of new and refurbished clean energy infrastructure will require a whole-of-government effort and strong state, regional, and local partnerships. EPA should work with the White House and Congress to ensure that its decarbonization proposals reflect current permitting needs and challenges.

  There are many emerging opportunities to support improved energy permitting. Implementing the DOE Regional Clean Hydrogen Hubs (H2Hubs) program, which will require new hydrogen and CO_2 infrastructure, as well as new electricity generation and transmission, will be a major opportunity for federal and state stakeholders to develop new ways to site and permit multi-jurisdictional and multi-sectoral energy projects. The IIJA created H2Hubs to address multiple challenges facing hydrogen infrastructure development. In October 2023, DOE announced $7 billion for seven regional selectees. Regions with a hub will have an advantage to jump-starting hydrogen market formation. Some regions, such as the Southeast, Central, and Northeast, did not receive hub funding.

  Meanwhile, the scale and pace of EPA's proposal does not match DOE's hubs plan. DOE requires each of the seven regional hubs to produce between 20 kilotons (kt) and 40 kt of hydrogen per year by 2035, while EPA's policy could require as much as 32 Mt, or 700 times more, by 2038.[13] Additionally, EPA could consider hub-like structures in its proposals to limit the sizable infrastructure builds needed for individual plants across many regions of the country.

  The administration should work with Congress to develop a public-private partnership model for CO_2 storage management to avoid costly project uncertainty related to CCS and blue hydrogen,[f] as well as other decarbonization technologies (e.g., direct air capture) that depend on CO_2 sequestration. The EFI Foundation offered a similar proposal in a December 2022 report.[14]
  Also, the Federal Energy Regulatory Commission (FERC) could begin the process of regulating the blending of hydrogen into interstate natural gas pipelines, an important step for hydrogen demonstrations that aligns with FERC authority.

[f] Gray hydrogen is produced from steam methane reformation of natural gas without using carbon capture and storage technology to capture the CO_2 emitted from production. When CO_2 is captured, the resulting hydrogen is called blue. Green hydrogen is produced from electrolysis using renewable electricity (solar and wind). When nuclear electricity is used instead, it is called pink hydrogen.

Introduction and Context

Reaching net-zero targets will require unprecedented investments and innovative solutions to reduce and remove greenhouse gas (GHG) emissions while maintaining vital energy services for homes, factories, and businesses across the country and world. Climate change has increased the frequency and intensity of heat waves, heavy precipitation, and droughts, with parts of the United States experiencing heavy rains and others drought-related wildfires. These trends demonstrate the need for accelerating emissions reductions across the economy and highlight the need for climate change-resilient systems.

Due to the relatively slow pace of technological change, the next decade will likely define U.S. options for reaching net-zero GHG emissions by midcentury. The electric grid can play a crucial role in rapid economywide decarbonization. The power sector is one of the largest contributors of GHGs in the United States, responsible for 25% of the nation's total emissions in 2022.[15] Shifting to a zero-carbon electricity system can directly reduce one-quarter of U.S. carbon dioxide (CO_2) emissions today and enable additional emissions reduction through increased end-use electrification in buildings, transportation, and other sectors.

In May 2023, the U.S. Environmental Protection Agency (EPA) proposed new emissions limits for fossil fuel-fired generators in the United States at a dynamic time for the sector. Electricity emissions have fallen by 40% from 2005 to 2022, with the sector shifting heavily to natural gas and renewable energy sources.[16]

The Biden administration set a target of 100% carbon pollution-free electricity by 2035, and utilities covering nearly 80% of U.S. customers have set 100% carbon reduction targets for midcentury.[17] The administration explicitly mentioned carbon capture retrofits and existing nuclear as key pathways. The Infrastructure Investment and Jobs Act (IIJA), the CHIPS and Science Act, and the Inflation Reduction Act (IRA) offer unprecedented financial incentives for economywide and electric sector decarbonization.

This report, *How Much, How Fast: Infrastructure Requirements of EPA's Proposed Power Plant Rules,* analyzes the infrastructure needs of the proposed EPA rules for fossil-fueled power plant emissions reductions. This analysis is driven by national and regional models of the United States using the SESAME (Sustainable Energy System Analysis Modeling Environment) framework to understand the EPA proposal's cost, emissions reduction potential, energy requirements, and the electricity and energy system infrastructure needs.

This report is part of a series, the *U.S. Hydrogen Infrastructure Action Plan*, which will build on this study to recommend options for accelerating economywide hydrogen uptake.

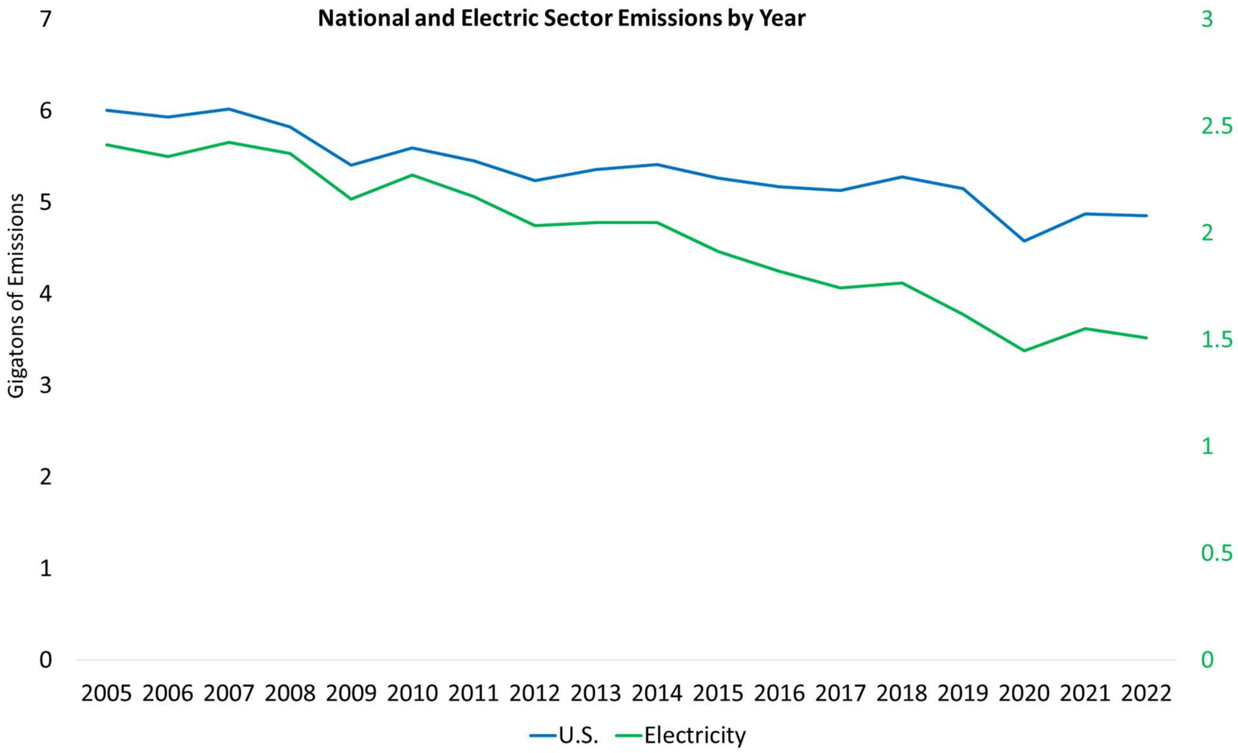
The electric grid continues to be the linchpin of U.S. decarbonization

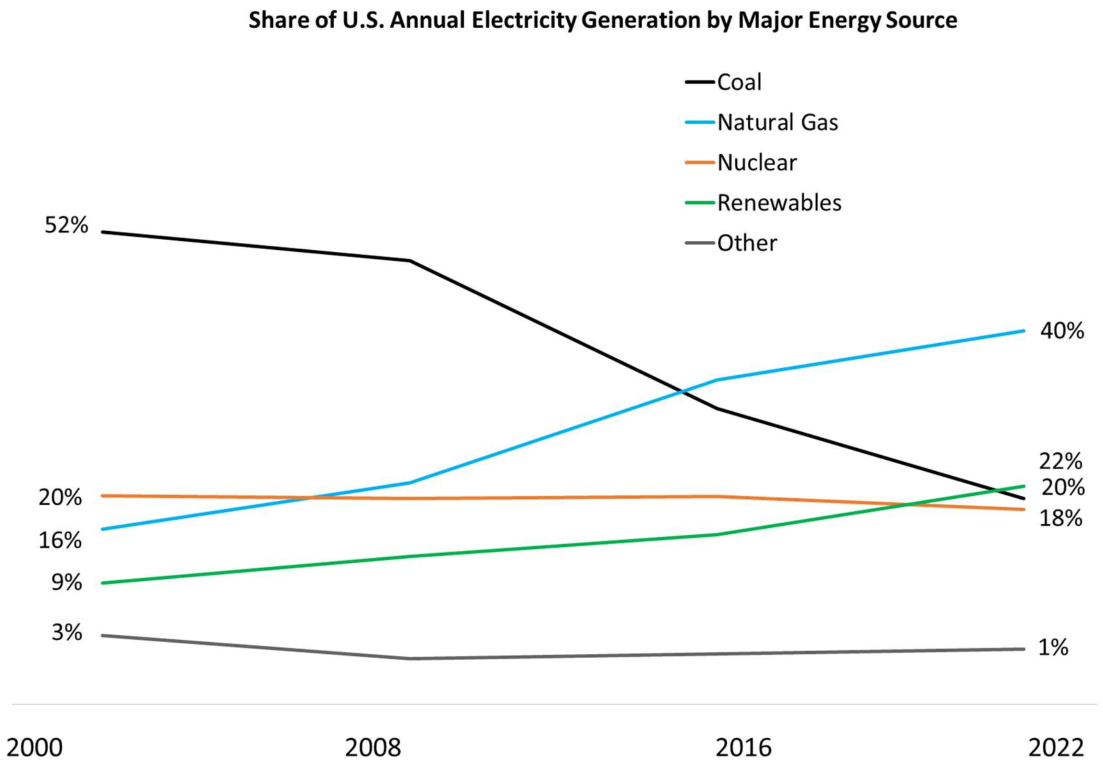
The electric grid has been the primary driver of U.S. emissions reduction in the last few decades. Electric sector GHG emissions were down 40% from 2005 to 2022, due mostly to the sector's shift from a coal-dominated system to one that relies on natural gas and renewables for 62% of total U.S. generation (Figure 1).[18]

Since 2000, gas generation has increased from 601 gigawatt-hours (GWh) to 1,689 GWh. Shifting to a zero-carbon grid can reduce roughly one-quarter of U.S. emissions, or roughly 1.5 gigatons in 2022, and enable additional emissions reductions through increased end-use electrification in buildings, transportation, and other sectors.

Figure 1.

Trends in the U.S. electricity sector





The use of natural gas and renewables in electricity generation has steadily increased since 2000, replacing coal and contributing to the electric sector emissions decreasing 40% from 2005 to 2022. Data from: See first figure mention in text for sources.

Many studies show that achieving 100% clean electricity will require a mix of resources, policies, and innovation for overcoming technical and economic barriers.[19] While grid decarbonization will require hundreds of gigawatts (GW) of new wind and solar generation, it also will depend on clean, dispatchable ("firm") power[g] and large-scale deployment of enabling infrastructure.

According to the National Renewable Energy Laboratory, electric grid decarbonization requires a massive acceleration in deployment rates and substantial development of infrastructure, including fuel storage, transportation and pipeline networks, and additional generation capacity needed to produce clean fuels.[20]

EPA's Regulatory Impact Analysis (RIA) finds that natural gas plants are expected to play an important role in the future energy mix—especially those paired with more efficient generation and emissions reductions pathways, including carbon capture and storage (CCS) and clean hydrogen blending. EFI Foundation modeling shows gas capacity will stay roughly flat through 2042 in the High H2 and High CCS scenarios but will increase measurably in

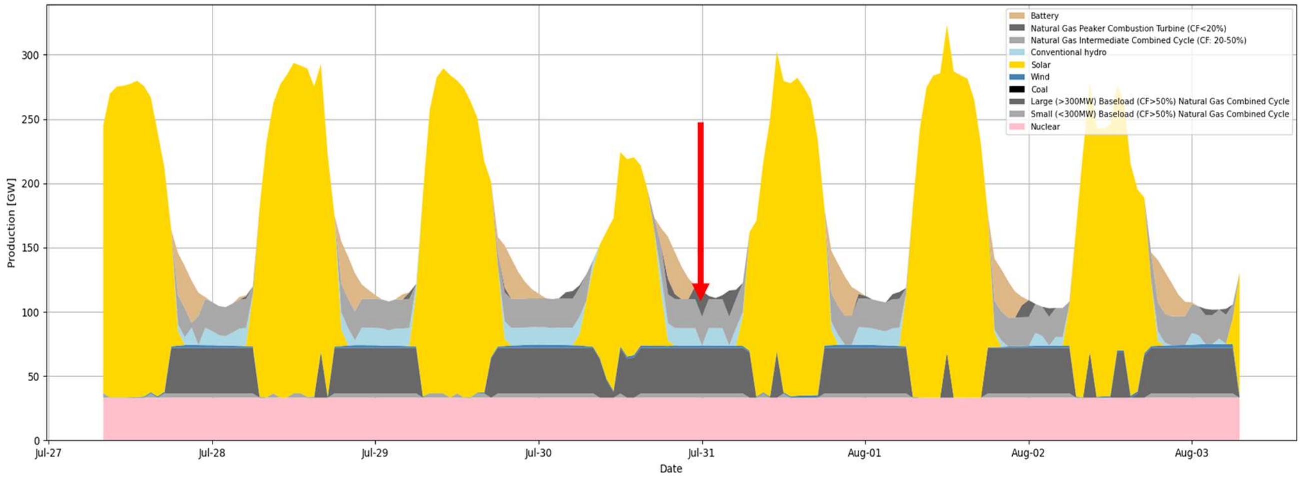
[g] Firm power is power or producing capacity designed to be available at all times.

the High RO scenario as additional small gas units come online to backfill lost generation from large units that ramp down.

Figure 2 shows the importance of gas for maintaining reliability for one region, the solar-rich Southeast, in 2042. The modeling shows natural gas (shown in gray scale) backfilling the system during daily periods of low solar output. Gas plays a major role in managing system reliability, in addition to battery storage, nuclear, and renewables.

Figure 2.

Modeling reliability in the Southeast shows important role for gas plants in 2042



Although solar energy is an abundant resource in the Southeast, natural gas peaker plants still need to be deployed to provide grid reliability when solar energy is not available. Source: EFI Foundation modeling analysis using SESAME tool.

As even more coal power plants retire throughout the country—another 50 GW of coal-fired capacity is scheduled to retire by the end of 2029[21]—and more renewables come on line, the operating profiles of existing and new gas units may change, moving down the dispatch order but remaining on-call for regular reliability support.

EPA is proposing more aggressive power sector decarbonization

On May 11, 2023, EPA proposed updating emissions reduction standards for new and existing fossil power plants using its authority under Section 111 of the Clean Air Act (CAA). The agency's Section 111 authority, which covers nearly all U.S. power sector emissions, requires EPA to create a framework for establishing national emissions standards for existing and new power plants.[22]

EPA's proposed rules address the scale of the challenge of reaching a carbon-free electric grid before midcentury though do not go as far as the Biden administration's goal of 100% carbon-free electricity by 2035.

According to EPA, its proposal would result in climate and health economic benefits of up to $85 billion and lead to cumulative emissions reductions of up to 617 million metric tons (Mt) by 2042. EPA finds that the majority (roughly 60%) of emissions reduction benefits would come from shutting down coal generation and the net reduction of building new natural gas-fired power plants with "best system of emission reduction" (BSER) emission controls. BSER encompasses highly efficient generating practices, co-firing clean hydrogen with natural gas, and CCS. The remaining benefits (roughly 40%) would come from retrofitting existing natural gas units with BSER technologies.[23] Figure 3 shows EPA's assessment of how the proposal would change the grid's energy generation and capacity mix through 2040.

Figure 3.

EPA's projected U.S. energy and capacity by fuel type from proposed rules

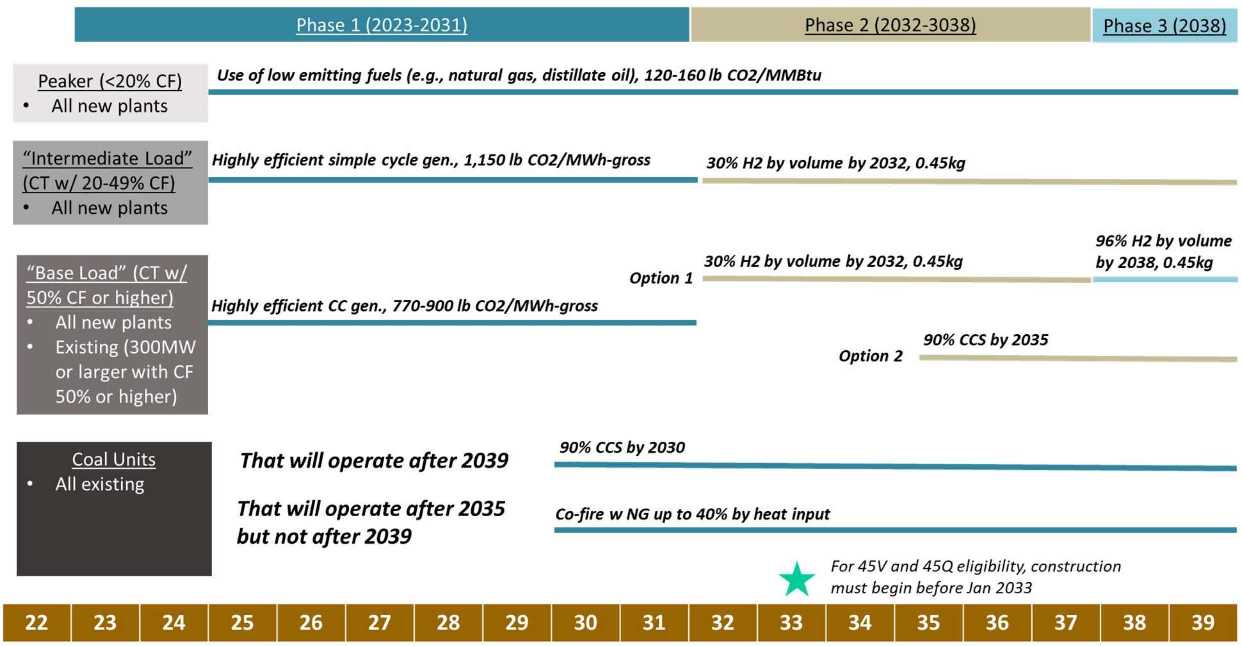
	Generation, TWh					*Capacity, GW*				
EPA proposal	***2022***	***2028***	***2030***	***2035***	***2040***	***2022***	***2028***	***2030***	***2035***	***2040***
Coal	*828*	*472*	*80*	*0*	*0*	*201*	*99*	*46*	*0*	*0*
Coal w/CCS	*0*	*0*	*85*	*85*	*65*	*0*	*0*	*12*	*12*	*9*
Natural gas	*1,689*	*1,783*	*1,846*	*1,290*	*1,044*	*520*	*467*	*460*	*476*	*512*
Natural gas w/ CCS	*0*	*0*	*31*	*66*	*54*	*0*	*0*	*4*	*8*	*8*
H_2 co-firing	*0*	*0*	*2*	*70*	*75*	*0*	*0*	*0*	*11*	*13*
Nuclear	*772*	*765*	*734*	*660*	*616*	*95*	*96*	*92*	*84*	*79*
Hydro	*262*	*294*	*303*	*328*	*346*	*100*	*102*	*104*	*108*	*110*
Renewables	*672*	*966*	*1,278*	*2,186*	*2,818*	*228*	*316*	*405*	*670*	*867*
Others (oil, etc.)	*11*	*60*	*79*	*47*	*31*	*39*	*70*	*76*	*74*	*74*
Totals	***4,234***	***4,340***	***4,438***	***4,732***	***5,049***	***1,183***	***1,150***	***1,199***	***1,443***	***1,672***
Note: 2022 data is from EIA, reporting actuals; data for 2028-2040 is from EPA RIA										

EPA's proposal requires more CO_2 emissions controls at natural gas- and coal-fired power plants that "operate more frequently and for more years and would phase in increasingly stringent CO_2 reduction requirements over time" (Figure 4).[24] The proposed requirements vary by:

- the type of unit (new or existing, combustion turbine or utility boiler, coal-fired or natural gas-fired).
- how frequently it operates (base load, intermediate load, or low load [peaking]).
- its operating horizon (i.e., planned operation after certain future dates).

Figure 4.

Timeline of EPA's proposed fossil generator rules



EPA's proposed rules for fossil fuel generators span 2023 to 2038 and encompass four categories: new peaker plants, which do not frequently operate (capacity factor, or CF, lower than 20%); new intermediate load plants (combustion turbines—CT—with CF between 20% and 49%); base load plants (CT with CF of 50% or higher), either new or existing (for the latter, capacity of 300 MW or larger); and all existing coal power plants. Each category has one or more pathways to decarbonize, depending on the time frame. Peaker plants will decarbonize using low-emitting fuels such as natural gas and distillate oil. Intermediate load plants need to increase efficiency of operating their simple cycle generation combustion turbines—measured in pounds (lb) of CO_2 per MWh-gross (which does not discount the electricity used to operate the power plant), until 2031 starting in 2032, clean hydrogen (with life cycle GHG emissions lower than 0.45 kg CO_2e/kg of H_2 produced) must be blended with the fuel used (natural gas) at a 30% rate. Base load plants also have to make their combined cycle (CC) generation combustion turbines more efficient until 2031; starting in 2032, however, they have two options to decarbonize: blending clean hydrogen with natural gas at a 30% by volume rate and then increasing that rate to 96% by 2038, or using CCS at a 90% capture rate by 2035. Coal units that will operate past 2039 need to deploy CCS at a 90% capture rate by 2030. On the other hand, coal units that will not operate past 2039 but will operate between 2035 and 2039 need to co-fire with natural gas (NG) up to 40% on a heat input basis. To be eligible for the hydrogen production tax credit (45V) or the carbon sequestration tax credit (45Q), projects need to begin construction before January 2033. Adapted from: See first figure mention in text for sources.

Overview of Section 111

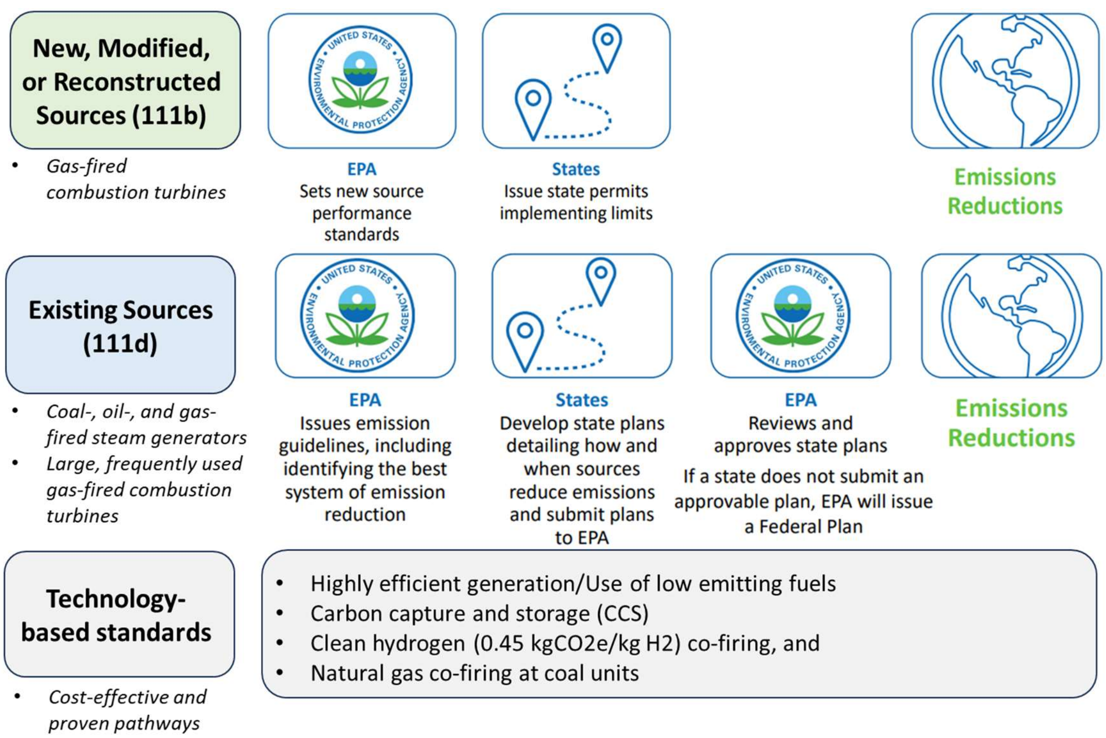
EPA is charged with developing separate emissions-reduction frameworks for new and existing power plants under CAA Sections 111(b) and 111(d), respectively (Figure 5).[25] Under Section 111, EPA can identify the types of facilities that should be regulated, distinguishing among classes, types, and sizes. The agency has considerable discretion in determining the appropriate level of emissions reduction for the standard.

For new facilities, setting emissions standards must reflect what EPA determines to be achievable through the application of the BSER, which factors in cost, non-air-quality health and environmental impacts, energy requirements, and control measures that have been adequately demonstrated.[26] Emissions standards for new plants must be reviewed at least every eight years and revised, if appropriate.

For existing facilities, EPA also uses BSER standards. Recognizing that existing sources do not have as much flexibility as new sources to build emissions controls into their design, Congress established a dynamic process for federal-state engagement on meeting the Section 111 requirements (referred to as “State Plans”). The requirements for a State Plan to be successful are, however, not clearly defined by EPA.

Figure 5.

Summary of EPA’s proposed Section 111 rules



New or existing power plants follow different guidelines to decarbonize according to EPA’s proposed Section 111 rules. New, modified, or reconstructed power plants are expected to be natural gas-fired combustion turbines. For such power plants, EPA will set emissions reduction standards and states will implement them. For existing fossil fuel power plants, *EPA and states will interact more to develop an emissions reduction strategy. The technologies that power plants will use to decarbonize are a mix of cleaner fuels (e.g., clean hydrogen, natural gas at coal units, or other low-emitting fuels), highly efficient generation, and CCS. Adapted from: See first figure mention in text for sources.*

New Gas Generators, 111(b)

EPA is proposing to update and establish more protective emissions standards for new and reconstructed fossil fuel-fired turbines, nearly all of which are expected to be natural gas-fired. EPA's proposal recognizes the growing importance of new gas-fired generators for the electric grid, especially as an enabler of increasing levels of renewable energy resources, aiming to achieve significant pollution reductions beginning in 2035.

In EPA's updated baseline scenario, factoring in systemwide benefits of IRA funding, the share of overall generation from natural gas combined cycle units increases from 36% to 40%.[27] EPA's proposal varies by different types of new gas-fired turbines, based on their level of use. The proposal includes three general subcategories:

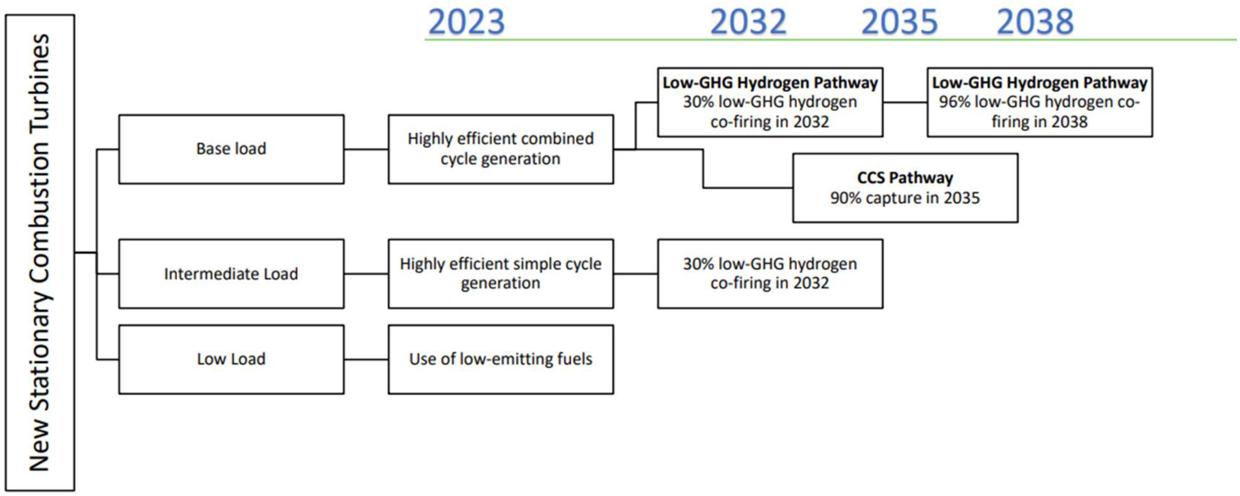
- Low load "peaking" turbines (19% or lower capacity factor [CF])
- Intermediate load turbines (20%-49% CF)
- Base load turbines (50% or above CF)

For each subcategory, EPA is proposing separate BSERs and performance standards based on the agency's evaluation of the feasibility, emissions reductions, and cost of available controls. Through 2031, the BSER for new peaking units is the utilization of "low-emitting fuels,"[h] and for intermediate and base load units, the BSER is highly efficient generation.[i] Starting in 2032, there is no additional requirement for peaking units. Intermediate and base load units have the option to employ either co-firing with clean hydrogen or CCS with 90% capture starting in 2032 and 2035, respectively. For the clean hydrogen pathway, there will be a ramp-up of co-firing from 30% by volume in 2032 to 96% by volume in 2038 (Figure 6).[28] EPA's proposal defines "clean" hydrogen as having a life cycle analysis (LCA) of 0.45 kilograms (kg) CO_2e/kg H_2.

[h] Up to 160 pounds CO_2/MMBtu

[i] Intermediate load: 1,150 pounds CO_2/MWh-gross; base load: 770 pounds CO_2/MWh-gross for units with a base load rating of 2,000 MMBtu/h or more or 770 pounds CO_2/MWh-gross for units with a base load rating of less than 2,000 MMBtu/h

Figure 6.
EPA proposal for new gas-fired turbines

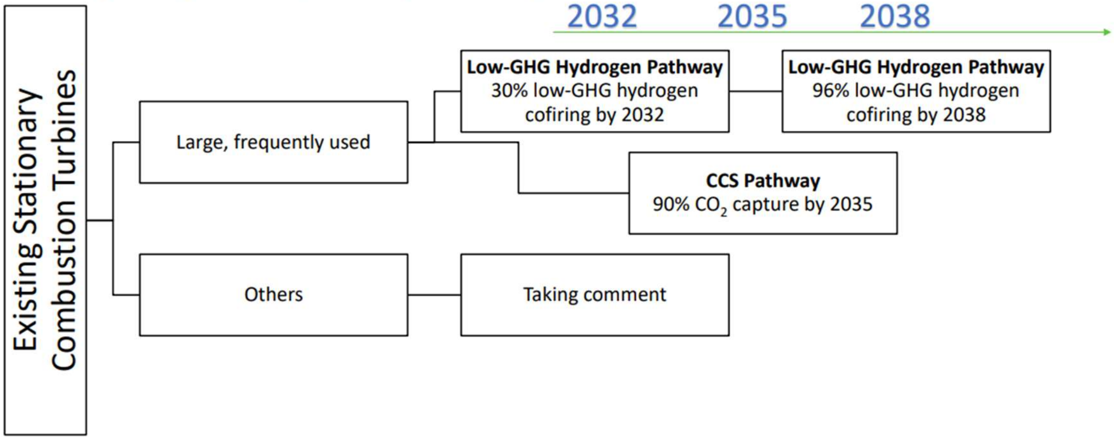


The rules to decarbonize new natural gas power plants vary according to frequency of use. Starting in 2023, low load (or peaker) power plants must use low-emitting fuels. In the same time frame, intermediate load power plants must increase the efficiency of their simple cycle combustion turbines. Starting in 2032, however, these units must blend clean hydrogen with natural gas at a rate of 30%. Base load plants must also employ highly efficient combined cycle combustion turbines starting in 2023. These units, however, can choose between two pathways to keep decarbonizing: In the first one, clean hydrogen co-firing at a rate of 30% must start in 2032, ramping up to 96% in 2038; if the second pathway is chosen, CCS at a capture rate of 90% must be deployed. Adapted from: See first figure mention in text for sources.

Existing Fossil Units, 111(d)

EPA is proposing separate guidelines for existing natural gas and coal generators. Existing gas power plants account for 40% of current electricity production and 43% of the sector's current GHG emissions. Recognizing that many existing gas units will be in service for decades, EPA is proposing emissions guidelines for frequently used facilities that are larger than 300 MW and have a capacity factor of greater than 50%. The BSER for these gas units is the same as the proposal for base load facilities under 111b, namely deploying either CCS with 90% capture by 2035 or co-firing clean hydrogen with natural gas at 30% by volume starting in 2032 and ramping up to 96% by volume in 2038 (Figure 7).[29] EPA is soliciting comments on how to approach all other existing facilities.[30]

Figure 7.
Existing large, frequently used gas-fired turbines



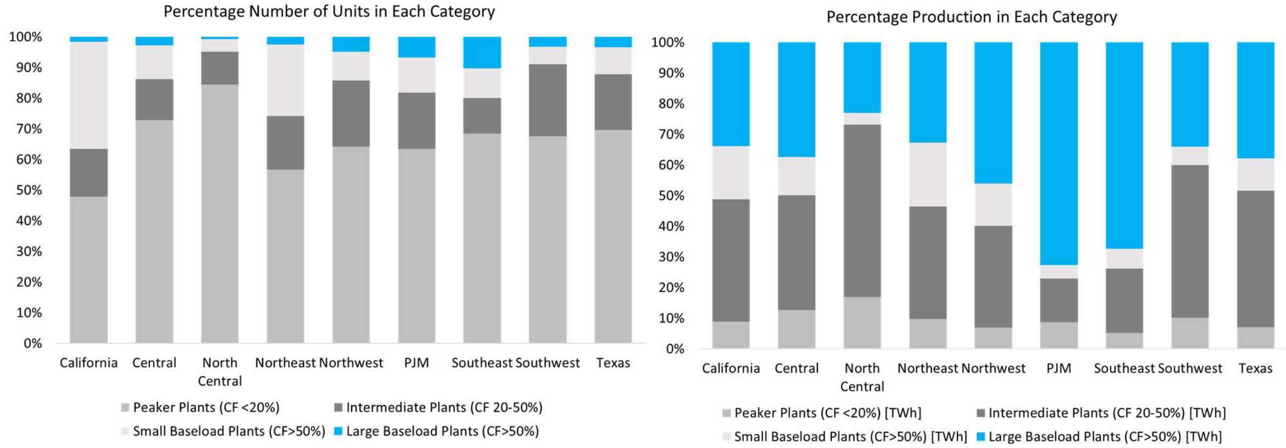
Large, frequently used existing combustion turbine power plants can choose between two pathways to decarbonize. In the first one, clean hydrogen co-firing at a rate of 30% must start in 2032, ramping up to 96% in 2038. With the second pathway, CCS at a capture rate of 90% must be deployed. For other types of existing stationary combustion turbines, EPA is currently soliciting comments about how to decarbonize those units. Adapted from: See first figure mention in text for sources.

There are roughly 200 existing gas units covered by EPA's proposal,[j] accounting for only 20% of total U.S. generation capacity. These units generate between 20% and 70% of the gas-fired generation in each region of the country (Figure 8).[31] Theoretically, base load facilities can reduce operations to below 50% CF to receive intermediate load status; however, this is a business and operational decision that would need to be weighed against the alternatives and could result in incentivizing building new peaker plants that do not require a BSER.

[j] Accounting for unit size (>300 MW) and capacity factor requirements (>50%)

Figure 8.

Number of gas units and regional share of generation impacted by EPA's proposal



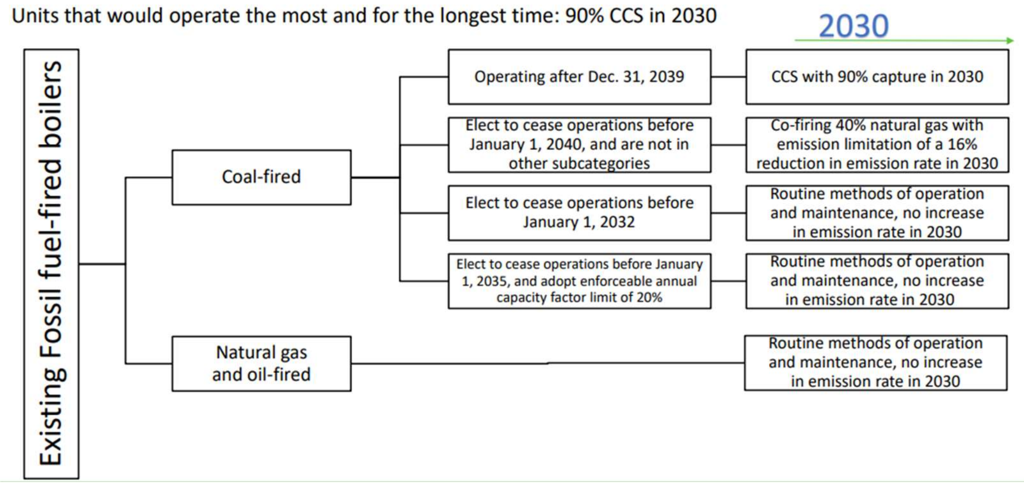
Most natural gas units in the country are peaker power plants. Large base load and intermediate plants, however, are responsible for most of the natural gas electricity generation in the United States. Source: See first figure mention in text for sources.

EPA is also proposing standards for existing coal-fired steam generators, based on the expected operating life of the unit (Figure 9).[32] According to EPA, in response to industry input and recognizing that the "cost-effectiveness of CO_2 controls depends on the period of time over which a plant will be operated," the agency is proposing separate BSERs depending on when the coal unit plans to permanently cease operation.[33] For facilities that will operate in the long term (i.e., after December 31, 2039), the BSER is the use of CCS with 90% capture rates. For any coal-fired unit that plans to permanently cease operations before then, EPA is proposing standards across three general categories:

- Medium-term: Units that commit to permanently cease operations before January 1, 2040.
- Near-term: Units that commit to permanently cease operations before January 1, 2035, and operate with an annual CF limit of 20%.
- Imminent-term: Units that commit to permanently cease operations before January 1, 2032.

Figure 9.

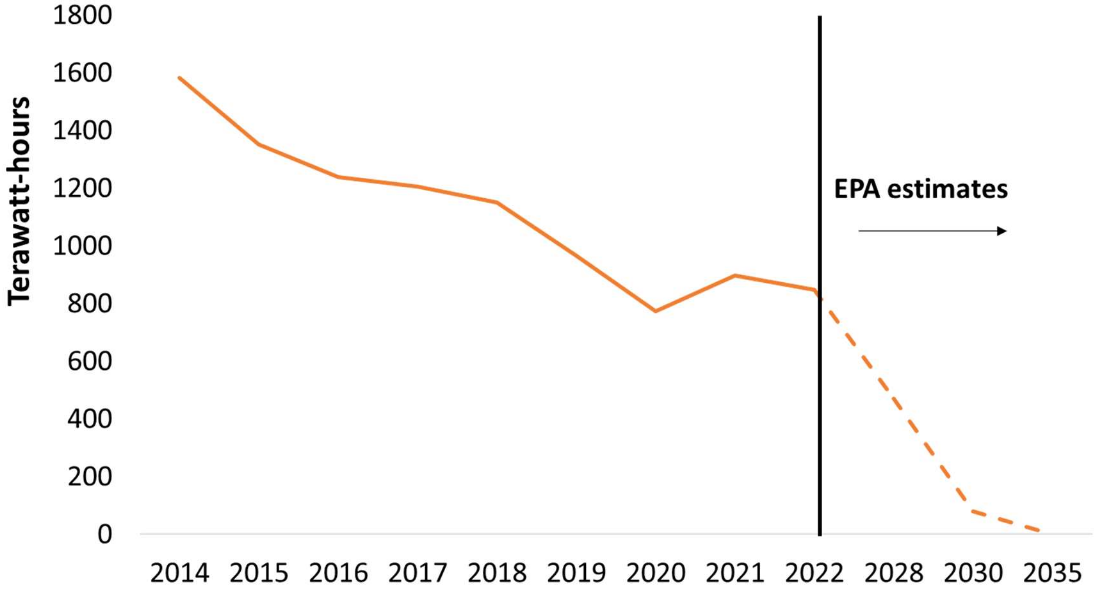
Existing fossil fuel-fired steam generators



For existing fossil fuel-fired steam generators (or boilers), decarbonization pathways depend on the fuel used. For natural gas and oil-fired steam generators, periodic maintenance must ensure that the emissions rate does not increase in and past 2030. The same criteria apply to coal-fired generators that decide to cease operations in 2032 and 2035. The latter also must enforce an annual capacity factor limit of 20%. Coal-fired boilers that decide to cease operations before 2040 and do not fit in other categories must co-fire with natural gas at a rate of 40% and must ensure that the emissions rate is reduced by 16% in 2030. Coal-fired boilers that will continue to operate past 2039 must adopt CCS with a 90% capture rate in 2030. Adapted from: See first figure mention in text for sources.

EPA's RIA shows its proposal would drive a rapid shift away from coal-fired generation (Figure 10). Roughly 830 TWh (200 GW) of coal generation would come offline between 2022 and 2035, driving sizable emissions reductions (roughly 1 gigaton) from the power sector.[34] To put this scale into perspective, total wind and solar generation was 400 TWh in 2022.[35]

Figure 10.
Historic coal generation and EPA's estimated impact of proposed rules



EPA estimates that the proposed rules would shift the power sector away from coal-fired generation by 2035, with roughly 830 TWh of coal generation coming offline.

State Plans

Section 111(d) of the CAA provides for dynamic federal-state collaboration in securing emissions reductions from existing power plants, with flexibility for states to identify their own optimal systems of emissions reduction while achieving the necessary environmental performance. According to EPA, once the final emission standards are issued, including the BSER for specific power plant types, states have 24 months to submit their own plans to EPA that are at least as stringent in terms of emissions reductions as EPA's guidelines.

This process is designed to give states the flexibility to consider regional factors when applying performance standards, possibly leading to different approaches to emissions reduction than the BSER identified by EPA. According to EPA, these State Plans can ensure that priorities, concerns, and perspectives of communities are heard during the planning process.[36] If EPA determines the State Plan inadequately meets the BSER standard, the agency must develop and implement a state-specific plan.

Tribes

Under Section 111(d), tribes may seek authority to implement their own plans, similar to a state. Tribes may choose to develop a Tribal Implementation Plan (TIP), offering the same flexibility as State Plans. If a tribe does not seek and obtain authority from EPA to establish a TIP, the agency has the authority to establish a federal plan for the tribe's areas where designated facilities are located.[37]

Communities

EPA's RIA offers suggestions for how its proposal can mitigate negative impacts to certain communities, including populations of concern in terms of environmental justice (EJ) and front-line groups. While EPA recognized that environmental justice concerns are "unique and should be considered on a case-by-case basis," the following questions should guide impact assessments:

1- Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline?
2- Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration?
3- For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?"

Per the RIA, meaningful involvement of communities requires that: 1) "potentially affected populations have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment and/or health," 2) "the public's contribution can influence the regulatory agency's decision," 3) "the concerns of all participants involved will be considered in the decision-making process," and 4) "the rule-writers and decision-makers seek out and facilitate the involvement of those potentially affected."

To begin analysis on community impact, EPA suggests a review of literature and prior community feedback concerning factors that make a given population more vulnerable to environmental harms, with analyses grouped into 1) baseline, or current distribution of exposures, risk, and disparities, and 2) policy, or distribution of exposures, risks, and disparities after the regulatory option has been applied.

Analyzing EPA's Proposed Rules for Decarbonizing Fossil Generators

EPA's proposal depends on sizable deployments, in the next decade and beyond, of electric infrastructure, CCS and clean hydrogen systems with relatively complex value chains. The scalability, cost, and timing of deployment of these technologies will be driven by the availability of their enabling infrastructure.

To evaluate these complex infrastructure issues, EFI Foundation used the SESAME platform, which combines technology deployment modeling with energy infrastructure analysis. National and regional energy system model scenarios were designed to evaluate EPA's proposal in terms of energy and capacity requirements, infrastructure needs, and systemwide costs.

Strategic takeaways

EFI Foundation modeling and research resulted in three major insights that may inform EPA's approach to its proposed rules for lowering emissions from existing and new fossil generators:

- CCS and clean hydrogen face first-of-a-kind (FOAK) challenges to deployment that must be addressed for at-scale deployment in the next decade.
- Meeting EPA's proposed rules will require major energy infrastructure builds development across the country that will not be ready in time for generators to comply with EPA's proposal without overhauls to project permitting regimes.
- The proposed BSERs are not available equally across the country, leading to regional variation in terms of system costs and the net emissions benefits that should be addressed.

Modeling Approach

EFI Foundation used the SESAME platform to evaluate options and impacts of technological, operational, temporal, and geospatial characteristics of the transitioning energy system.[38] SESAME focuses on the accurate estimation of life cycle GHG emissions, techno-economic assessment, and the scalability and feasibility of emerging technologies.

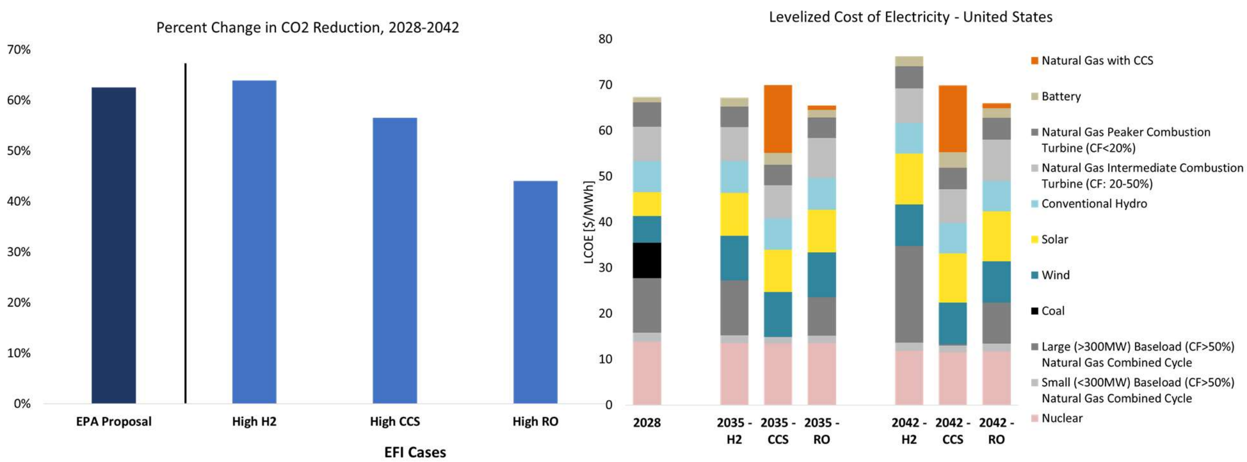
National and regional model scenarios were created to profile the systemwide impacts of meeting EPA's proposal in 2028, 2035, and 2042. This analysis used the U.S. Energy Information Administration's *Annual Energy Outlook 2023 Reference Case* for power demand forecasts and generation profiles for all technologies.[39] A deep-dive analysis was performed on natural gas and coal units—the focus of EPA's proposal—to understand their current operational profiles by region using EPA's Emissions & Generation Resource Integrated Database (eGRID).[40] This is important as EPA's proposal affects natural gas plants based on their size and capacity factors.

Three modeling scenarios, each focused on the major elements of EPA's proposal, were developed to understand a range of potential impacts on the system by 2028, 2035, and 2042: 1) high hydrogen demand ("High H2"), 2) high CO_2 capture rates ("High CCS"), and 3) high reduced operations ("High RO"), which refers to the option for large, frequently run power plants to lower their CF to reduce their policy compliance costs.

The modeling results show the proposed rules could lead to a range of emissions reductions and levelized electricity costs, depending on the scenario (Figure 11). In the High H2 scenario, the overall emissions benefits are slightly higher in terms of the percentage of CO_2 reduction than in EPA's proposal and nearly 20% higher than in the High RO scenario. One reason why: In the High RO scenario, as large units reduce operations to comply with the policy, new, smaller gas units not covered by the policy come on line, resulting in emissions. The levelized cost of electricity (LCOE) also varies by scenario over time, with major cost increases in renewables and the rapid shift to CCS and clean hydrogen in the power sector.

Figure 11.

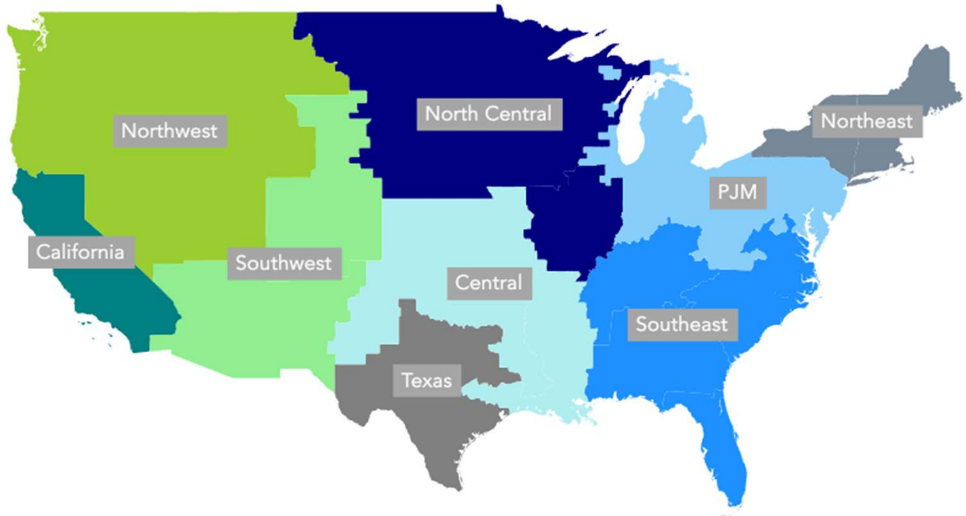
Comparing CO_2 reduction and electricity cost estimates of EPA's proposal



On the left, the percentage change in CO_2 emissions reduction between 2028 and 2042 can be 20% higher between the High H2 and High RO scenarios. Percent reduction was used rather than absolute terms as EPA's baseline year (2028) assumed a large increase in gas-fired generation from 2022, before a large reduction by 2042. EFI Foundation modeling used different assumptions, making a comparison on absolute terms possibly misleading. The graph on the right shows the contribution of each generation technology to the levelized cost of electricity in each scenario in 2035 and 2042. Only grid costs are included. Source: EFI Foundation modeling analysis using SESAME tool.

For each scenario, hourly electricity dispatch was modeled for 2028, 2035, and 2042 in each of the nine regions, delineated by EIA zones, which combine North American Electric Reliability Corporation (NERC) and independent system operator (ISO) regions (Figure 12). Integrated hydrogen and CCS models were used to assess the infrastructure requirements of the policy proposal.

Figure 12.
Map of modeled regions



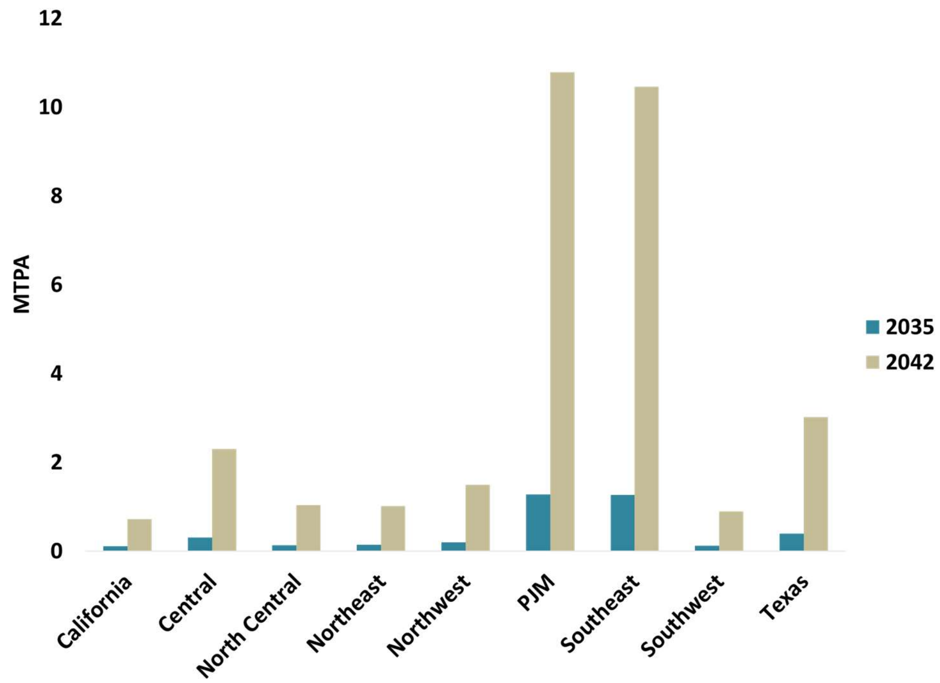
In this analysis, the United States was divided into nine regions following the EIA zones, which combine the NERC and ISO regions. Source: EFI Foundation modeling analysis using SESAME tool.

High Hydrogen Scenario

In the High H2 scenario, each region was constrained to only the hydrogen pathway. All new and existing (300 MW and larger) base load units (50% CF or higher) adopted co-firing hydrogen by 30% by volume in 2032, and 96% by 2042 to comply with EPA's proposal. All new intermediate load units employed 30% co-firing starting in 2032. As the results show (Figure 13), U.S. regions with a larger number of these assets demand more hydrogen than other regions. Annual hydrogen demand would grow substantially by 2042 to more than 32 Mt, aligned with EPA's proposal. For reference, there is effectively no clean hydrogen produced or consumed in the United States today.

Figure 13.

Annual hydrogen demand by region in High H2 case, 2035 and 2042



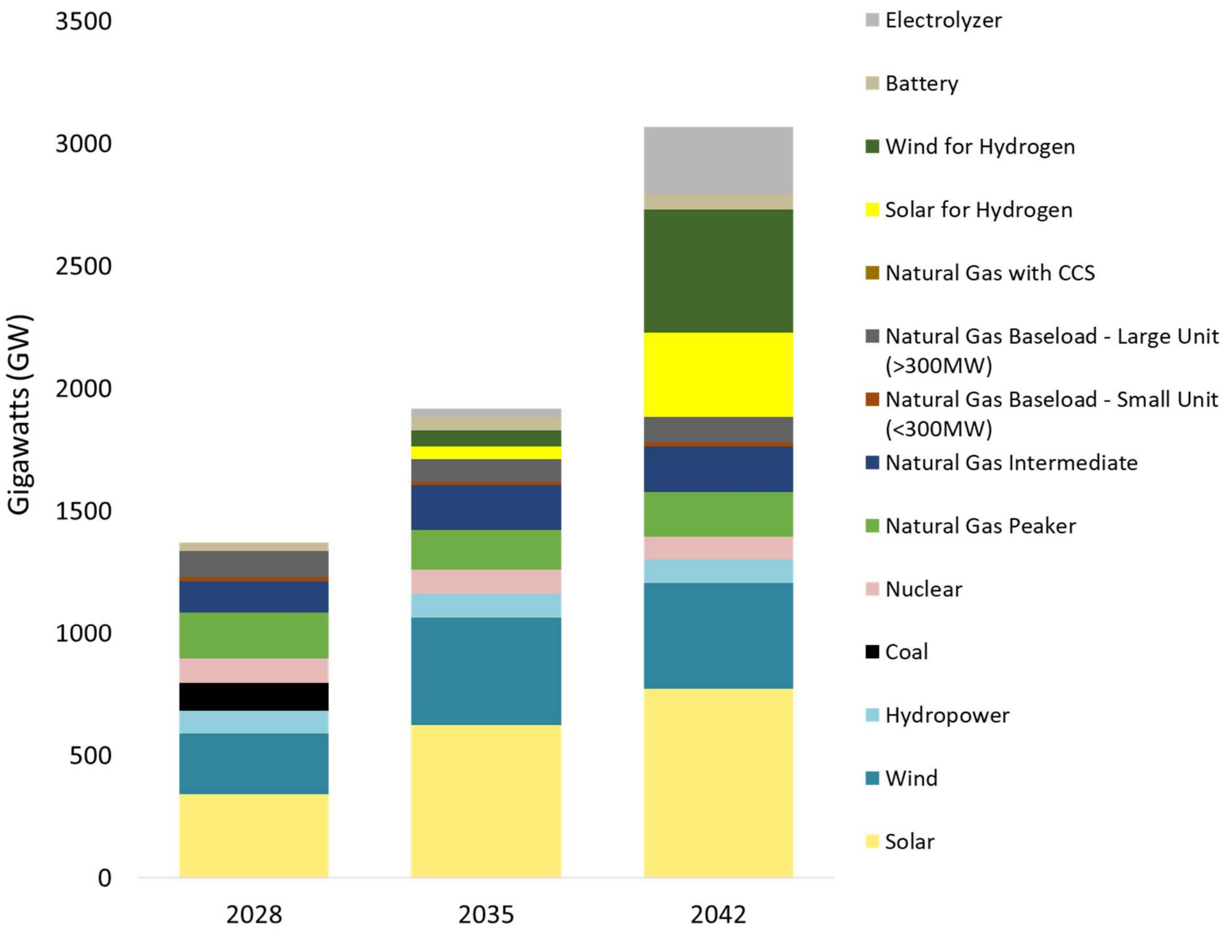
Only the clean hydrogen pathway is a decarbonization alternative in the High H2 scenario. Clean hydrogen demand in 2042 reaches more than 32 million metric tons per year (MTPA). Source: EFI Foundation modeling analysis using SESAME tool.

Figure 14 shows electric grid capacity by technology in the High H2 scenario. EFI Foundation projects 30% hydrogen co-firing on 105 GW of gas-fired generation by 2035 and 96% co-firing on 124 GW by 2042, substantially higher than EPA's estimates of 11 GW and 13 GW, respectively.

To produce the clean hydrogen, 115 GW of dedicated renewables are needed in 2035 and 850 GW by 2038. EFI Foundation's modeling shows that EPA's proposal would likely drive all coal generation out of the system by 2035 because of the timing and cost challenges of deploying CCS on coal by 2030. Hydrogen demand is factored in according to the policy requirements, and battery storage is incorporated to help manage hourly reliability needs by region.

Figure 14.

Installed capacity in High H2 case



Coal generation is phased out of the system by 2035 in the High H2 case. Because the rate of hydrogen blending increases substantially between 2035 and 2042, renewables' installed capacity (solar and wind) to produce clean hydrogen also grows. Source: EFI Foundation modeling analysis using SESAME tool.

One state-level example illustrating the modeling approach is Arizona, which depends on natural gas (42%), nuclear (29%), coal (12%), solar (10%), hydroelectricity (5%), and wind (1%) for its power system capacity and generation. [41] EIA's *AEO Reference Case* forecasts large decreases in coal and gas generation, matched in part by increases in wind and solar, and stable hydro and nuclear through midcentury.

Modeling of the High H2 scenario shows similar trends for coal and nuclear, though increases in natural gas by 2042, to cover the lost coal capacity and generation. There are increases in intermediate (16%) and peaker (10%) units that have lower or no policy requirements.

Meanwhile, new dedicated renewables for hydrogen production would exceed the region's grid-connected wind and solar by 2042. This is driven by the EPA's proposed requirement of

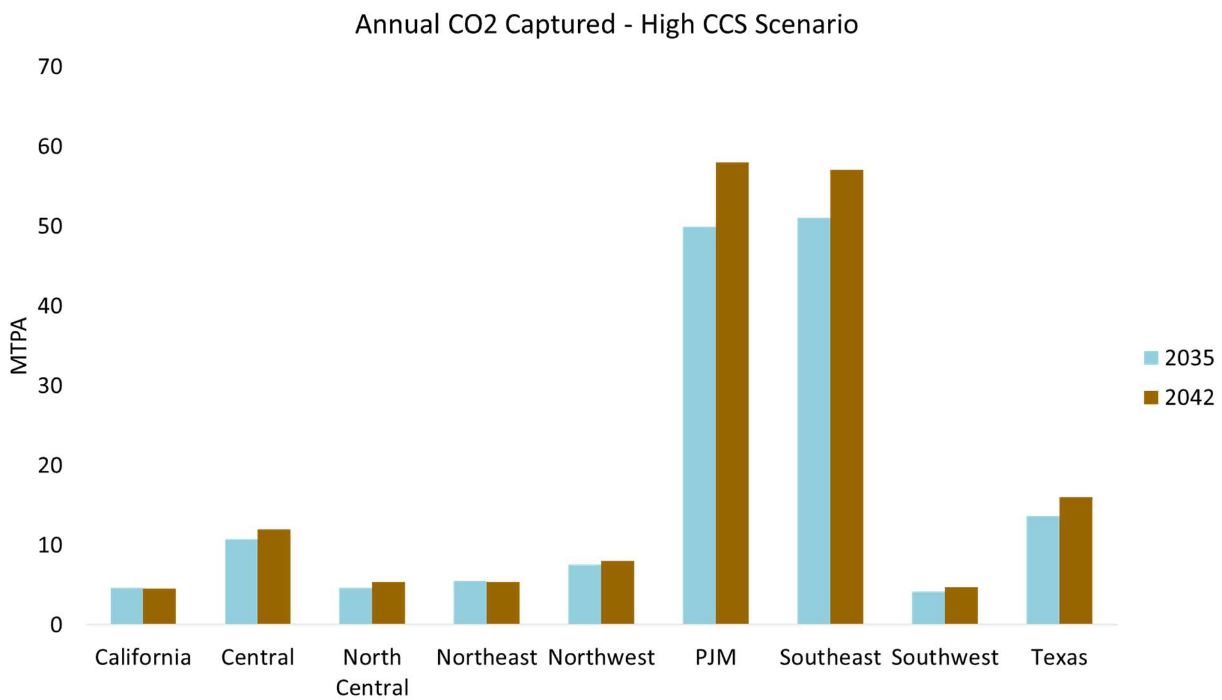
0.45 kg CO_2e/ kg H_2, as only renewables are assumed to be producing hydrogen. In the other scenarios, described below, the overall system capacity is smaller, though similar dynamics exist where new smaller, gas capacity is needed to cover large lost coal.

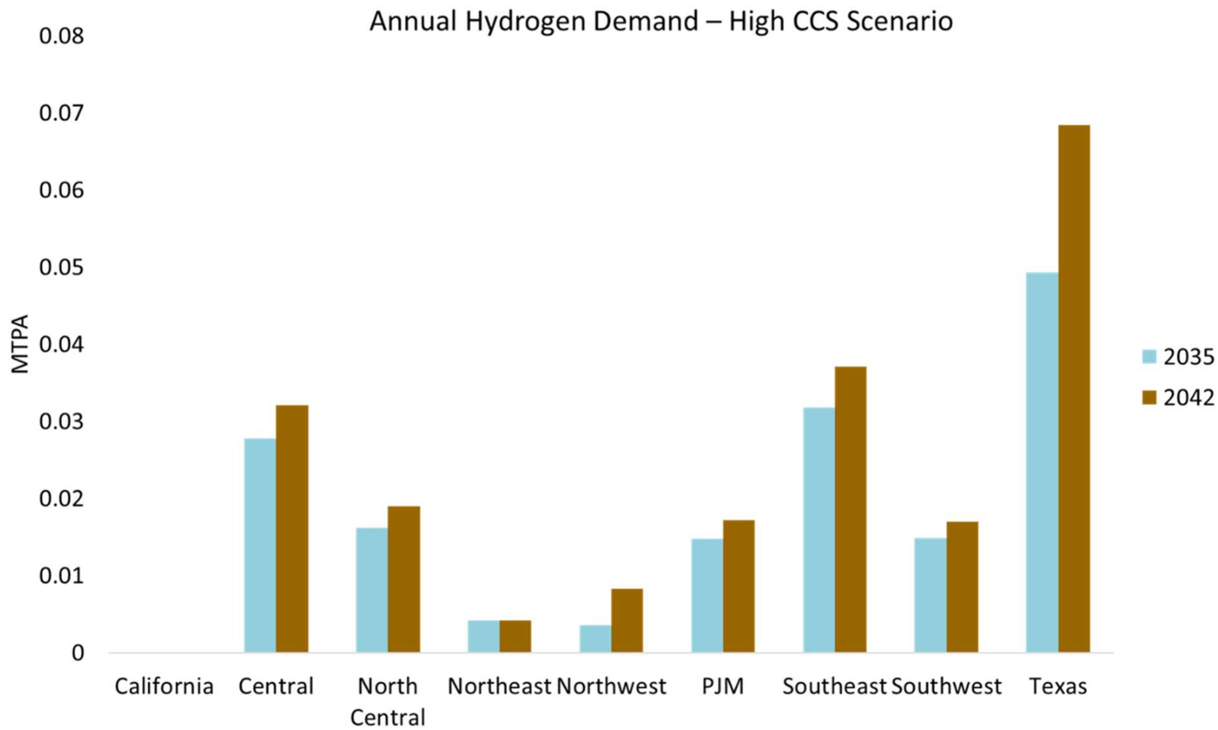
High CCS Scenario

In the High CCS scenario, all base load units adopt CCS by 2035, per EPA's proposal, while new intermediate load units deploy 30% hydrogen co-firing in 2032. Using the EIA's *Annual Energy Outlook 2023 Reference Case* as a baseline, the SESAME model solved for grid reliability in 2028, 2035, and 2042. The results show that roughly 170 Mt per year of CO_2 would need to be captured by 2042 in this scenario (Figure 15). Hydrogen demand in the High CCS case is around 0.2 Mt per year by 2042, closer to EPA's estimate of hydrogen demand in its proposal: 0.32 Mt per year by 2040.

Figure 15.

CO_2 captured and H_2 demand in High CCS case



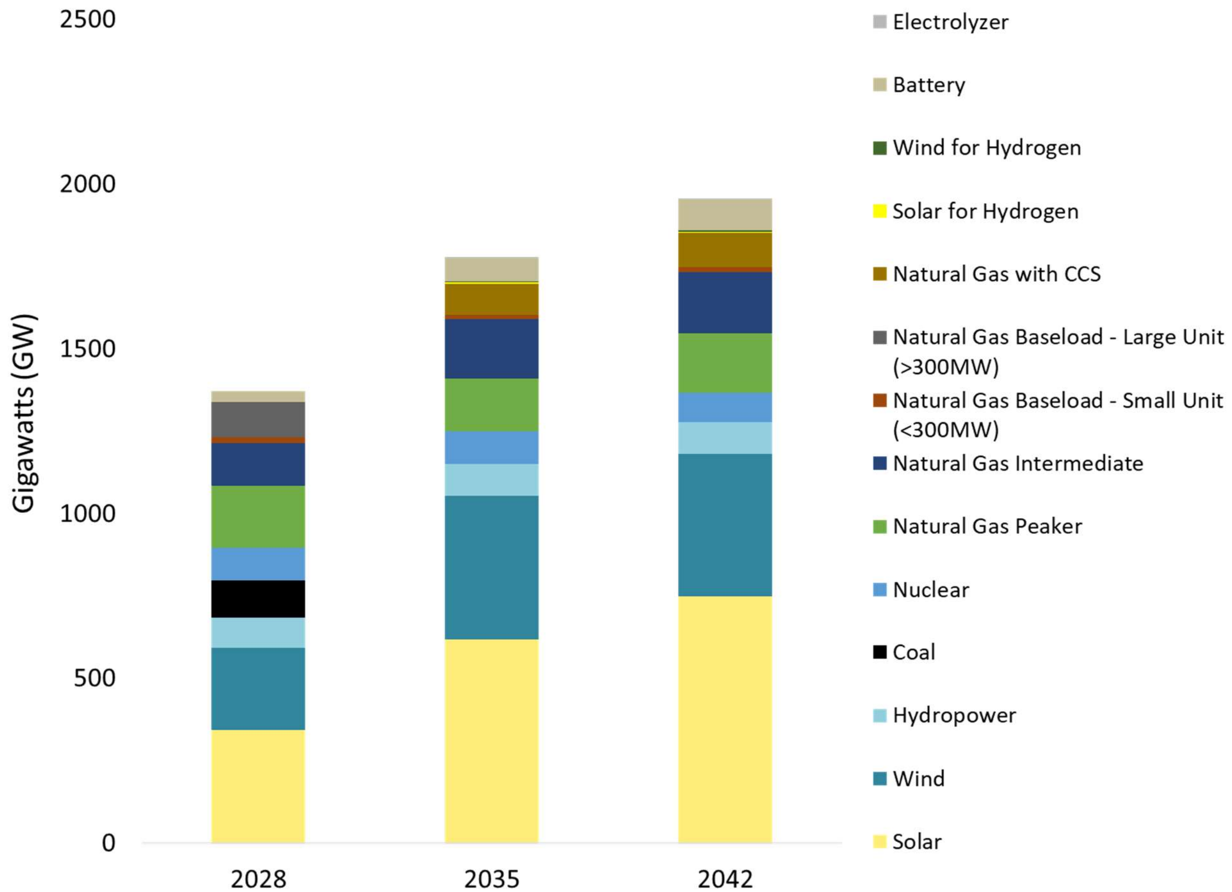


In the High CCS case, CO_2 is mostly captured in regions where large plants are located (PJM, Southeast). Hydrogen is demanded by intermediate load plants to co-fire with natural gas in regions where these plants are mostly located (e.g., Texas). Because CCS is a viable option, hydrogen demand in this scenario is closer to EPA's estimates. Source: EFI Foundation modeling analysis using SESAME tool.

Figure 16 shows the electric grid capacity by technology in the High CCS case. EFI Foundation projects CCS on 94 GW of gas-fired generation by 2035 and 105 GW by 2042. Using EIA's *Annual Energy Outlook 2023 Reference Case* as a baseline, covering the lost coal capacity is done through CCS at natural gas plants, hydrogen co-firing at intermediate load units, increases in renewables, and battery storage. Hydrogen demand is factored in according to the policy requirements, and battery storage is incorporated to help manage hourly reliability needs by region.

Figure 16.

Installed capacity in High CCS case



Coal is replaced by natural gas with CCS in the High CCS case, as well as hydrogen co-firing at intermediate load units, increases in renewables, and battery storage. Renewable capacity to produce hydrogen is not substantial because hydrogen demand is not extensive. Source: EFI Foundation modeling analysis using SESAME tool.

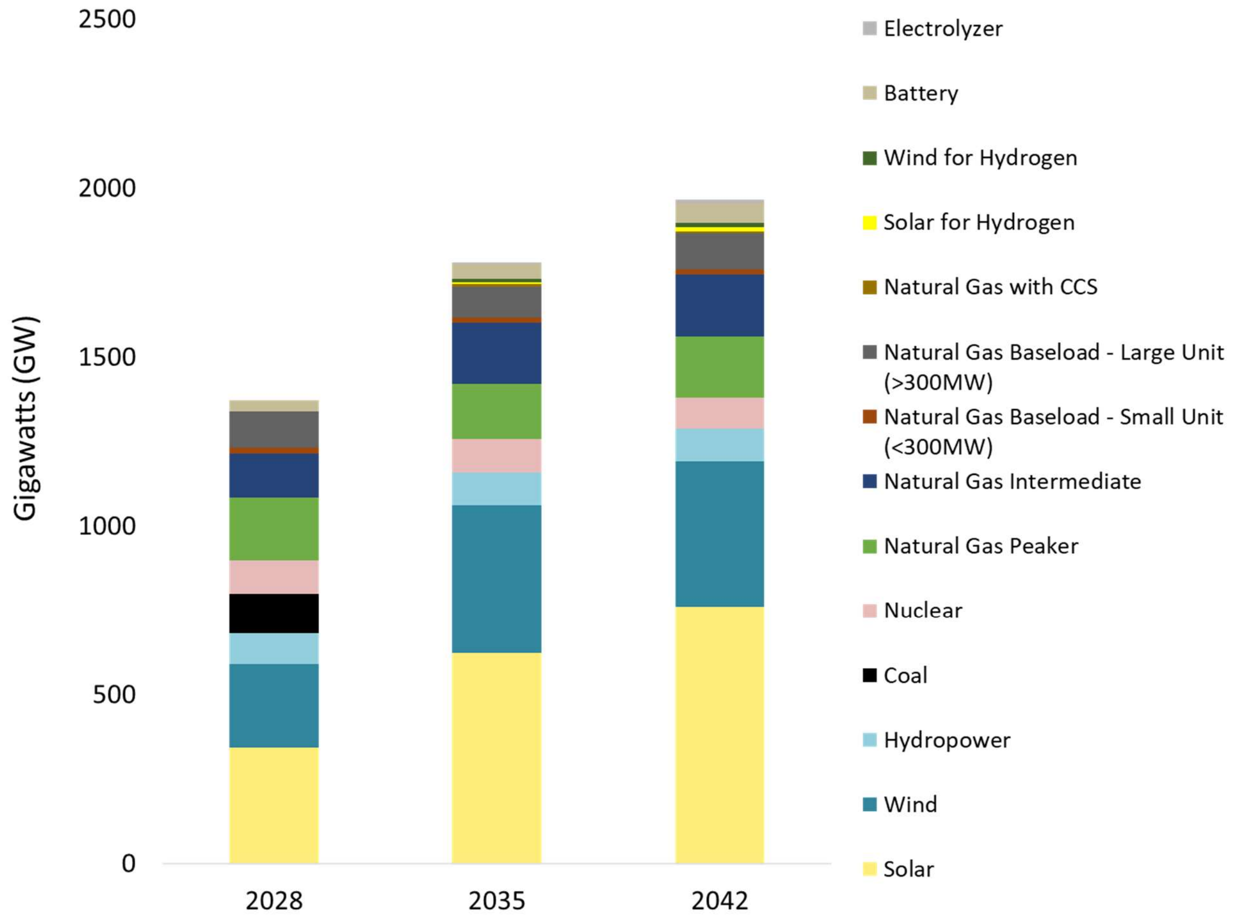
High Reduced Operations Scenario

Because EPA's proposal covers facilities based, in part, on the type of unit (e.g., combustion turbine or boiler) and how frequently it operates (base load, intermediate load, peaker), certain types of plants can change how they operate to adjust their policy compliance needs. The decision for large (at least 300 MW) base load units (50% or CF) to ramp down operations to be classified as an intermediate load unit (20%-49% CF) would be based on an array of factors, including how many hours per year of reduction is needed and the cost of backfilling the lost generation.

To model this in the High RO scenario, all large base load units reduce operations to 49%. To help cover the resulting supply shortfall of roughly 100 TWh in 2042, it is assumed that all intermediate load units ramp up operations to 49% CF. The SESAME model chooses the cost-optimal resources to fill the remaining gap to cover reliability at an hourly resolution. While there may be no clear market signal for the intermediate units to ramp up, the lost generation from the large base load units could create a large supply shortfall and serious reliability concerns. Figure 17 shows the electric grid capacity by technology in 2042 in the High RO scenario.

Figure 17.

Capacity by technology in High RO case



In the High RO case, base load units reduce operations to 49% CF to classify under the intermediate load rules. To ensure supply, all intermediate load units in the system also ramp up to 49% CF. As a result, natural gas plants have a higher participation in capacity than in the other scenarios. Source: EFI Foundation modeling analysis using SESAME tool.

Policy Analysis and Insights

EPA's proposal sets deployment targets for emerging technologies, namely CCS and clean hydrogen, that will play a major role in economywide decarbonization. The United States has the industries, workforce, and resources to scale both CCS and clean hydrogen—

possibly to gigaton-scale emissions reductions. The Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA) invested heavily in these decarbonization pathways, jump-starting their development.

However, the EPA proposal's deployment time frames—2030 for 90% capture on coal plants, 2032 for 30% co-firing of hydrogen with natural gas, and 2035 for 90% CCS capture rates—combined with the lack of commercial projects today present major challenges for immediate national scaling without complementary actions and policies. The following sections show the major insights from EFI Foundation modeling and analysis that may inform EPA's approach to decarbonizing existing and new fossil generators.

Power sector applications for CCS and clean hydrogen face first-of-a-kind project costs

The EPA's cost assumptions for natural gas with CCS and delivered clean hydrogen may not include the first-of-a-kind (FOAK) costs that reflect the engineering, policy, and financial challenges of both technologies. For natural gas with CCS, EPA assumes $85/metric ton (t) for new builds and $95/t for retrofits. For clean hydrogen, EPA assumes $0.5/kg for delivered clean hydrogen starting in 2032. EFI Foundation projects FOAK costs for CCS for gas generators may be up to 40% higher than EPA's estimates, while average U.S. delivered hydrogen costs could be up to 20 times higher.

While FOAK costs are much higher than those of n^{th}-of-a-kind—technologies in market deployment stage—early movers across multiple CCS and clean hydrogen applications are critical for starting the learning process. Without these early movers, necessary cost reductions will not appear and commercial liftoff in the time frames proposed by EPA will be challenging. EPA can begin to support this by aligning its proposals to IRA requirements for CCS and clean hydrogen.

Carbon Capture and Storage Costs

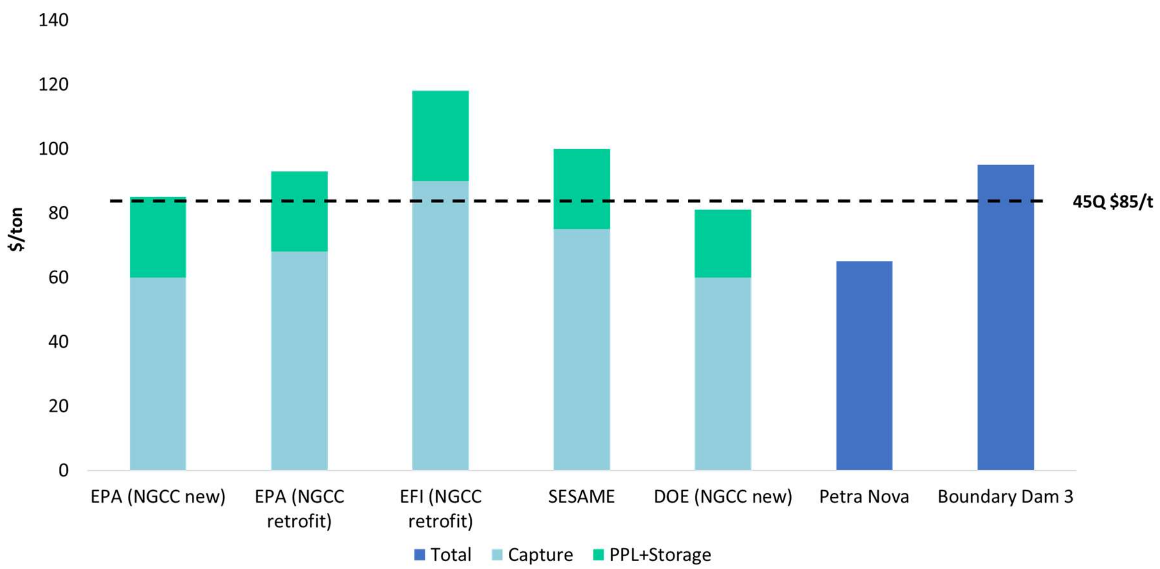
The United States has a long history of demonstrating post-combustion carbon capture. The Petra Nova CCS project, located in Houston, was a coal-fired plant retrofitted with CCS in 2017. It was one of the largest CO_2 capture projects in the world, using the CO_2 for enhanced oil recovery. The project ceased operations in 2020. Currently, there are at least nine announced CCS Front-End Engineering Design (FEED) studies on natural gas combined cycle power plants, mostly focused on improving the capture technology on a performance and cost basis.[42] Bringing these projects on line will be critical for driving down project costs.

Cost gaps need to be overcome to support the deployment of these projects. First, the 45Q tax credit—the primary federal policy supporting CCS in the U.S.—may not cover FOAK costs for CCS in power generation. The IRA made considerable improvements to the 45Q tax credit, including increasing its value from $50/t to $85/t. However, EFI Foundation estimates FOAK costs for CCS for gas and coal generators at $110/t to $120/t and $100/t to

\$110/t, respectively, much higher than the expanded 45Q tax credit value of \$85/t (Figure 18).[43]

Figure 18.

Comparison of CCS project costs



Although the IRA has increased the value of the 45Q tax credit to \$85/t of CO_2 captured, it does not fully cover the cost of retrofitting natural gas combined cycle (NGCC) and coal power plants with CCS technologies, whose costs are around \$110/t-\$120/t and \$100/t-\$110/t, respectively. Source: See first figure mention in text for sources.

First-mover projects will need to cover FOAK costs to support industry learning and build investor confidence in each commercial setting. Those costs range between 20% and 30% of the total project cost, according to the National Energy Technology Laboratory.[44] For example, each CCS project requires a capture technology engineered for a specific plant's flue gas characteristics, including temperature, pressure, CO_2 concentration, and the presence of other chemicals and impurities.[45] It will take effort to tune carbon capture to each new heterogeneous application, and progress in one setting may not translate seamlessly to another. The innovation of multiple applications will be needed to drive down project costs.

Additionally, the 45Q tax credit cannot be claimed until after the CO_2 is stored and verified under EPA guidance. In many cases, the CO_2 capturing entity is different from the organization managing the CO_2 storage and monitoring. This adds financial risks to CCS projects. Meanwhile, CCS value chain complexity creates coordination costs and development risks that are disadvantageous to most developers, relative to other clean energy projects.[46] Aligning capture, transportation, sequestration, ongoing site care, and long-term liability transfer elements creates project uncertainty. These are crucial next steps for CCS that may be challenging to address to reach the scale of commercial projects needed by 2035 to support the emissions reduction and reliability of EPA's proposal.

The IRA directed considerable funding into the 45Q tax incentive. In addition to expanding the credit's value to $85/t, the IRA extended the construction window for eligibility of the CCS projects for 45Q credits to January 1, 2033. However, EPA's proposal requires coal and gas generators to decide on their pathways by 2030 and 2032, respectively. Extending EPA's deadline to be aligned with the existing 45Q policy requirements could improve investor confidence concerned with the timing and uncertainty of developing and permitting CCS projects.

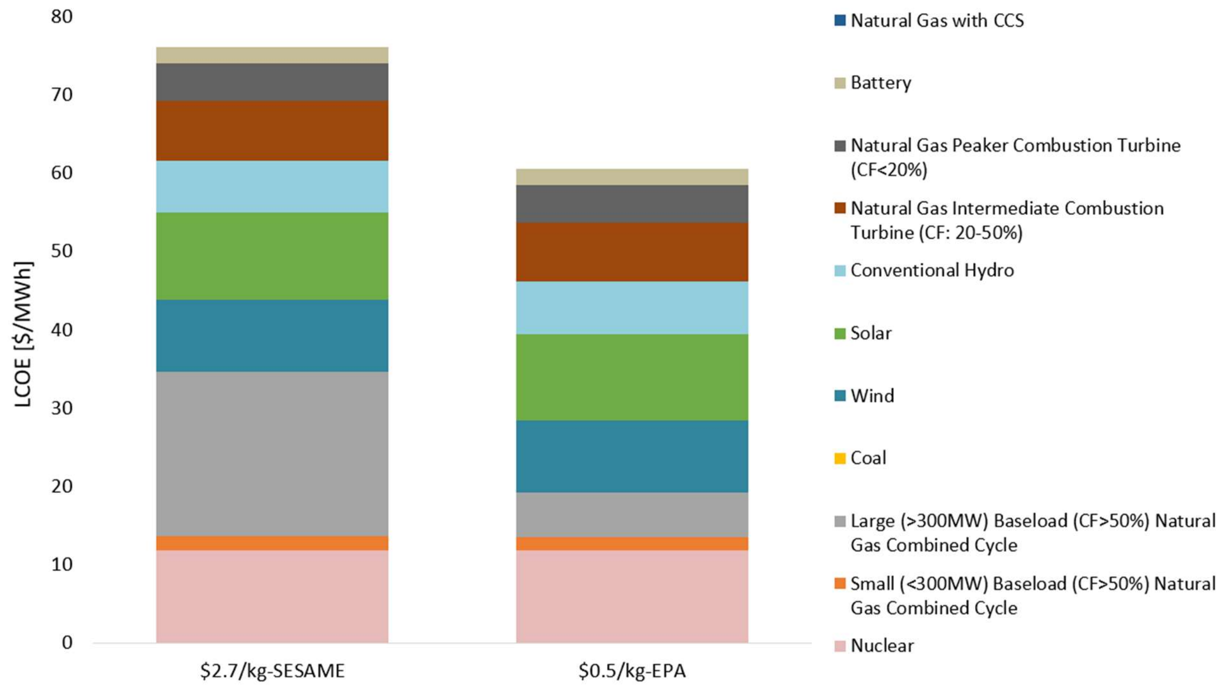
Clean Hydrogen Costs

The U.S. maintains one of the world's largest hydrogen industries, though virtually no clean hydrogen is produced or consumed there today. In 2021, the United States produced roughly 11.4 Mt of "gray" hydrogen, more than 15% of the world's total. Even though the IRA's 45V tax credit—the primary U.S. financial incentive for clean hydrogen projects—defines clean hydrogen as having an LCA of less than 4.0 kg CO_2e/kg H_2, EPA's proposed rule defines clean hydrogen as having life cycle emissions of 0.45 kg CO_2e/kg H_2. This greatly changes the type, scale, and regional diversity of eligible hydrogen production projects for making this very low-emissions product. Moreover, scaling up this low-carbon hydrogen will depend on new electrolysis capacity, new clean electricity supply, and enabling systems that do not currently exist.

EFI Foundation estimates the average U.S. cost of clean hydrogen as $2.7/kg, including $3/kg of 45V incentives. This is much higher than EPA's estimate of $0.5/kg starting in 2032. The difference in LCOE of these estimates can be considerable (Figure 19). There are large cost gaps that need to be overcome to support the deployment of these projects to bolster the grid with clean firm resources.

Figure 19.

Comparing LCOE using EPA and EFI Foundation (High H2 case) clean hydrogen costs



The cost of clean hydrogen estimated in this analysis ($2.7/kg) is much higher than the value estimated by EPA ($0.5/kg), resulting in a higher levelized cost of electricity (LCOE) in the High H2 case. High clean hydrogen demand from large base load natural gas combined cycle power plants, which need to co-fire clean hydrogen at 30% and 96% volume by 2032 and 2038, respectively, contributes to this result. Source: EFI Foundation modeling analysis using SESAME tool.

EPA's cost target does align with DOE's estimate of power generators' "willingness to pay" for clean hydrogen in the $0.4-$0.5/kg range by 2030.[47] However, EPA's cost estimate may not include the total delivered cost that includes the enabling infrastructure, such as pipelines and storage. The cost of delivering and storing clean hydrogen can add roughly $2/kg to the total cost of production (Figure 20).[48]

Figure 20.

DOE's estimated delivered hydrogen costs

Blue hydrogen pathway example				
Production	***Delivery***	***Storage***	***End Use***	***Totals***
Steam methane reformation (SMR) w/CCS, **\$0.4-\$0.85/kg**	Gas compression, **\$0.1-\$0.4/kg** H_2 pipeline, **\$0.1/kg** Gas phase trucking, **\$0.7-\$1.5/kg**	Salt cavern storage, **\$0.1/kg** Compressed tank, **\$0.8/kg**	Natural gas blending, **\$0.4-\$0.5/kg**	**\$2.6-\$4.25/kg**
Green hydrogen pathway example				
Water electrolysis, **\$0.4/kg (w/PTC)**	Liquefaction, **\$2.7/kg** Liquid trucking, **\$0.2-\$0.3/kg**	Liquid storage, **\$0.2/kg**	Power generation (high-capacity firm), **\$0.4-\$0.5/kg**	**\$3.9-\$4.1/kg (w/ PTC)**
EPA estimate for "green" hydrogen (i.e., 0.45 kg CO_2e/Kg H_2)				
EPA estimate, **\$0.5-\$1/kg (w/PTC)**				**\$0.5-\$1/kg and (w/PTC)**

EPA's estimate for green hydrogen does not seem to include the costs of enabling hydrogen infrastructure to deliver and store hydrogen, such as pipelines and storage, which can add roughly \$2/kg to the final hydrogen production cost. These estimates already include the hydrogen production tax credit (PTC), also known as 45V. Source: See first figure mention in text for sources.

The need to bring down costs and scale the entire clean hydrogen value chain motivated the IIJA's \$8 billion Regional Clean Hydrogen Hubs (H2Hubs) program, aiming to "demonstrate the production, processing, delivery, storage, and end-use of clean hydrogen."[49] It likely will be another decade before the full lessons are learned from the H2Hubs program, as the execution of these demonstration projects is expected to take eight to 12 years.[50]

EPA's proposal depends on rapidly overcoming permitting challenges of enabling infrastructure

EPA's proposed rules aim to rapidly accelerate decarbonization through technology-based targets. EFI Foundation modeling shows the proposal could drive all coal generators to retire by 2035, leading to a fivefold increase in solar and a threefold increase in wind capacity by 2035 compared to today. While some of these new projects could be developed in locations to take advantage of existing infrastructure, it is likely that massive enabling infrastructure builds will be required: Hundreds of GW of new transmission, hundreds of GW of new renewables dedicated to clean hydrogen production, and major deployments of CCS infrastructure will still be needed.

EPA's RIA assumes these new resources are available and interconnected to seamlessly replace the missing energy and capacity. EPA's proposed rules should consider the permitting challenges when determining the compliance costs of its policy. These transition challenges could derail the sector's ability to implement EPA's proposal.

While the IIJA and IRA incentives support CCS and clean hydrogen, neither policy adequately addresses the permitting reform needed to develop and scale CCS and clean hydrogen. In the past year, both the White House and Congress have pushed for energy infrastructure permitting reform aligned to the pace and scale needed to realize the full economic benefits of the IRA.

In May 2022, the White House announced the Biden-Harris Permitting Action Plan, a series of administrative actions to "strengthen and accelerate Federal permitting and environmental reviews." After the passage of the IRA, U.S. Sen. Joe Manchin (D-W.Va.) proposed the Building American Energy Security Act of 2022 (BAESA), which focused specifically on permitting for energy projects. In 2023, House Republican leadership introduced H.R. 1, the Lower Energy Costs Act, which also included a major focus on energy project permitting reform.

Most CCS and clean hydrogen projects have value chain components that are separate industries with different needs (e.g., skill sets) and requirements (e.g., permits), each regulated independently with little federal coordination. CCS and clean hydrogen projects depend on new pipelines, power lines, new sources of electricity, and above- or below-ground storage, among other infrastructure. Assuming there is no financial risk of building out the system, needs across multiple sectors and many regions—each with different regulatory systems—may underestimate the compliance costs and timing of the proposed rules.

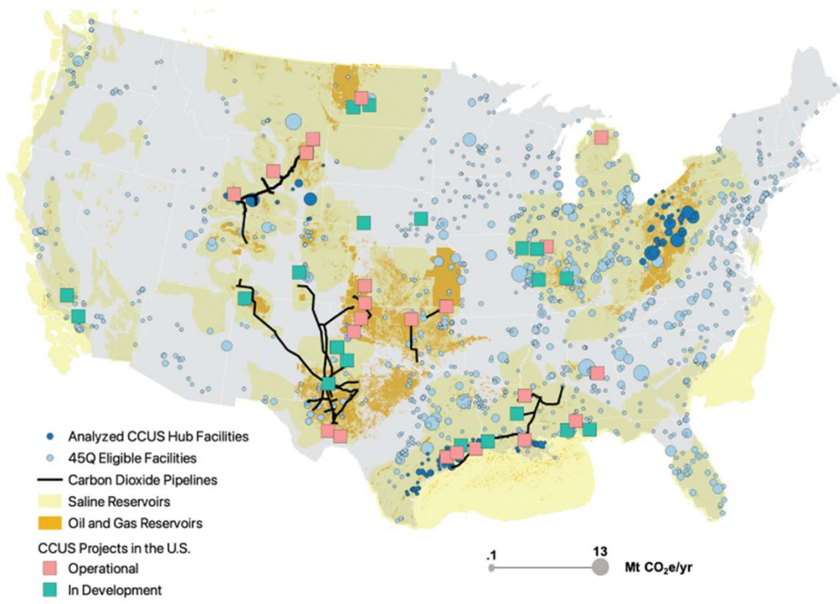
Carbon Capture and Storage Infrastructure

Carbon capture and storage (CCS) and transport systems enable a range of CO_2 abatement strategies. These systems are likely to play a vital role in reaching economywide net-zero emissions. As EPA's proposal reflects, CCS can support both increased renewable energy generation and grid reliability by enabling low-carbon firm power generation. Fuels, including hydrogen, produced with CCS have lower life cycle emissions, helping to decarbonize transportation and industrial end uses that are difficult to electrify.

The United States has abundant geologic resources for permanent long-term CO_2 storage and an existing network of CO_2 pipelines, spanning 4,500 miles and servicing mainly enhanced oil recovery projects (Figure 21).[51] There is roughly 20 MTPA of CO_2 capture capacity in the United States today—though none of it is in the power sector. There are at least nine announced CCS FEED studies on natural gas combined cycle power plants, mostly focused on improving the capture technology on a performance and cost basis.[52]

Figure 21.

Existing CCS infrastructure and 45Q-eligible facilities



Existing CCS-enabling infrastructure in the United States includes CO_2 pipelines and storage sites such as saline and oil and gas reservoirs. The map also shows the location of facilities eligible for the carbon sequestration tax credit (45Q), as well as the location of operational and under-development CCS projects. Source: See first figure mention in text for sources.

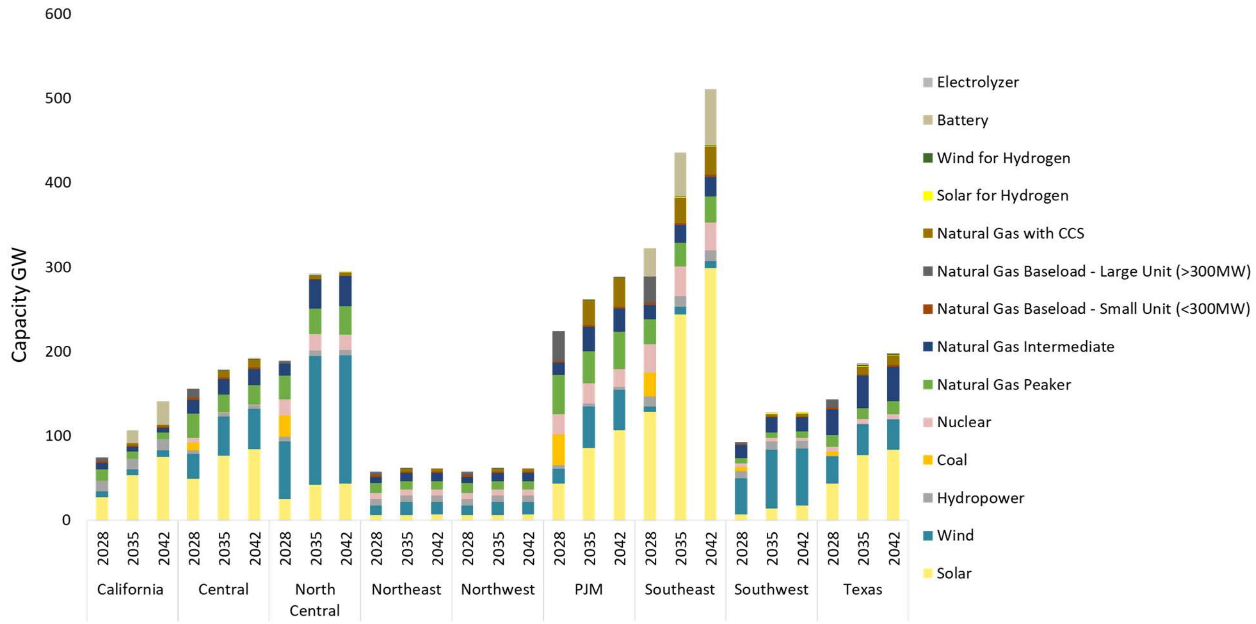
Modeling Results

In EFI Foundation's High CCS scenario, all coal is phased out by 2035, which profoundly impacts certain regions, including PJM, the Southeast, and North Central. The approach for covering that supply shortfall depends on each region's existing resources and the size and types of assets also impacted by EPA's proposal. Natural gas continues to play a role, with capacity increases in small base load, and large base load with CCS.

In this scenario, EPA's proposal requires CCS on 94 GW of gas-fired generation by 2035 and 105 GW by 2042. For context, installed capacity for all natural gas plants was 520 GW in 2022. Total renewables increase fivefold by 2042, while gas-fired capacity decreases slightly to 470 GW, aligned with EPA's estimates. Hydrogen demand is factored in according to the policy requirements, and battery storage is incorporated to help manage hourly reliability needs by region. Relatively small amounts of dedicated renewables (8 GW by 2042) are needed for clean hydrogen production in this scenario (Figure 22).

Figure 22.

Installed capacity by region in High CCS case

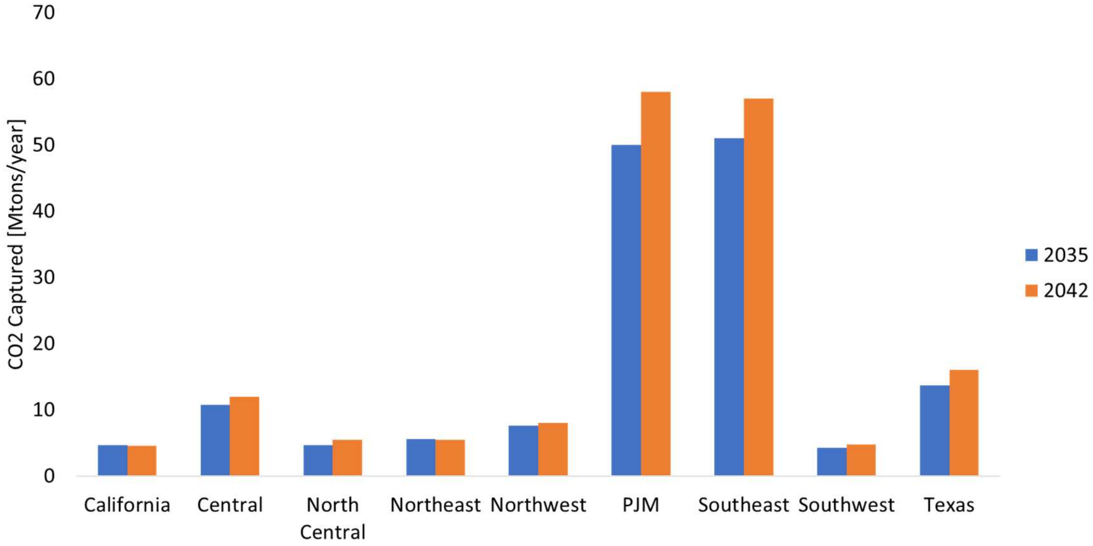


In the High CCS scenario, base load natural gas power plants must deploy CCS in 2035. The regions where most of these plants are located (e.g., PJM, Southeast, Southwest, Texas) experience an increase in installed capacity for these units. Source: EFI Foundation modeling analysis using SESAME tool.

With 90% capture rates set by EPA's proposal, there would be 150 MTPA of captured CO_2 in 2035 and roughly 170 MTPA by 2042 (Figure 23).

Figure 23.

Total CO_2 captured in High CCS scenario

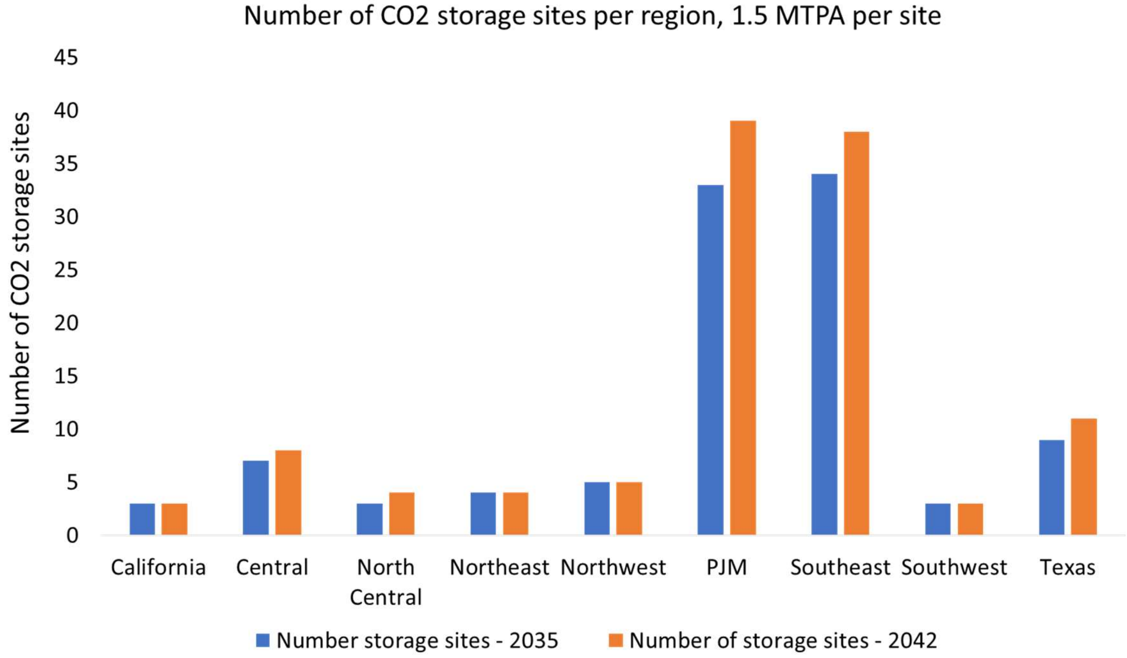


The amount of CO_2 captured in the High CCS case is higher in the regions with the most natural gas base load plants, which must adopt CCS technologies from 2035. Source: EFI Foundation modeling analysis using SESAME tool.

There are many options for building out the storage and pipeline infrastructure needed in the High CCS scenario. It is assumed that CO_2 cannot be piped between regions, recognizing some of the permitting challenges of building new energy infrastructure across state lines. Assuming each geologic storage site can handle 1.5 MTPA, the High CCS scenario results in a total of 101 sites in 2035 and 115 in 2042 (Figure 24). Increasing the capacity at each site affects the number of sites needed and the size of the pipeline infrastructure required.

Figure 24.

Number of CO_2 storage sites per region in High CCS scenario

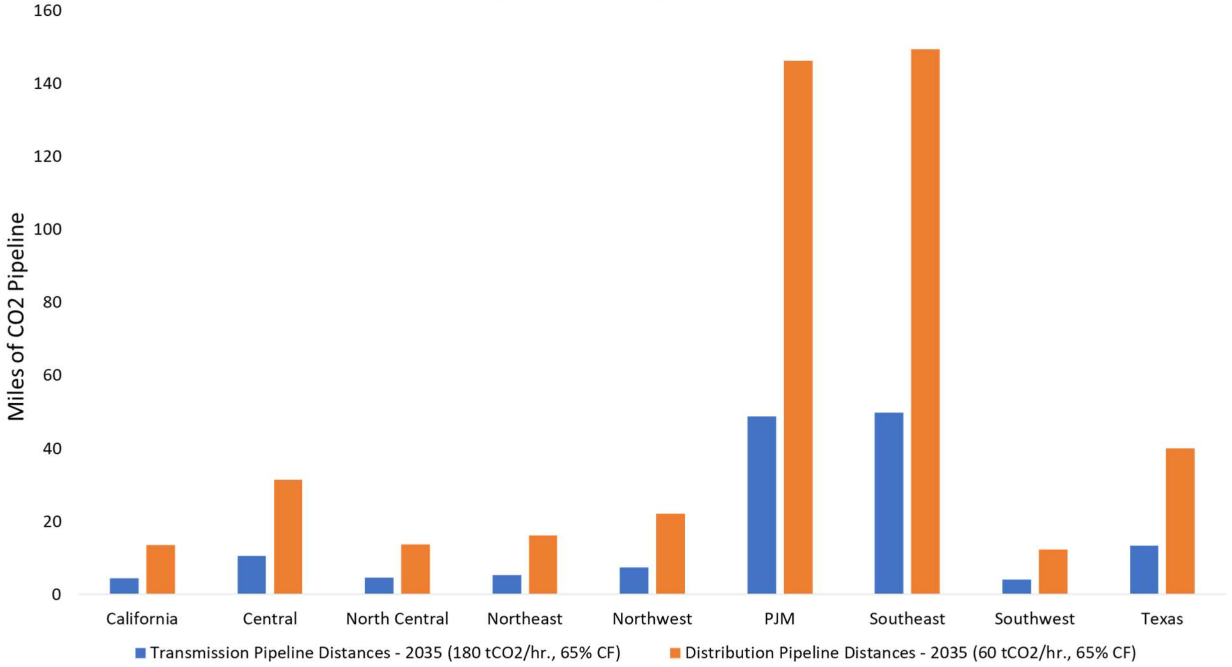


The PJM and Southeast regions, where most natural gas base load plants that adopt CCS in this scenario are located, have suitable CO_2 storage sites in saline and oil and gas reservoirs (see Figure 21). Source: EFI Foundation modeling analysis using SESAME tool.

A large network of transmission and distribution pipelines would be needed to enable the High CCS scenario, carrying CO_2 from sources to sinks. It was assumed that sufficient pipeline capacity could be built to handle the CO_2 volumes captured in each policy scenario, traveling the shortest distance from the gas unit to the center of a CO_2 storage resource, according to the National Carbon Sequestration Database and Geographic Information System (NATCARB).[53] To simplify the estimate, it is assumed that each CCS unit is supported by at least one transmission pipeline that can carry 180 metric tons of CO_2 per hour. The results show that, by 2035, roughly 150 large CO_2 transmission pipelines covering over 50,000 miles would be needed (Figure 25). Other studies suggest that the United States will need 30,000 to 66,000 miles of CO_2 pipelines by 2050 to meet net-zero targets, allowing for another two decades to sort through permitting and other issues.[54]

Figure 25.

Miles of CO_2 pipelines by region in High CCS scenario by 2035



A large deployment of CO_2 transmission and distribution pipelines would be needed to transport captured CO_2 to storage sites around the country. As expected, pipeline needs are higher in the regions with the most CCS deployment. Source: EFI Foundation modeling analysis using SESAME tool.

Permitting Challenges

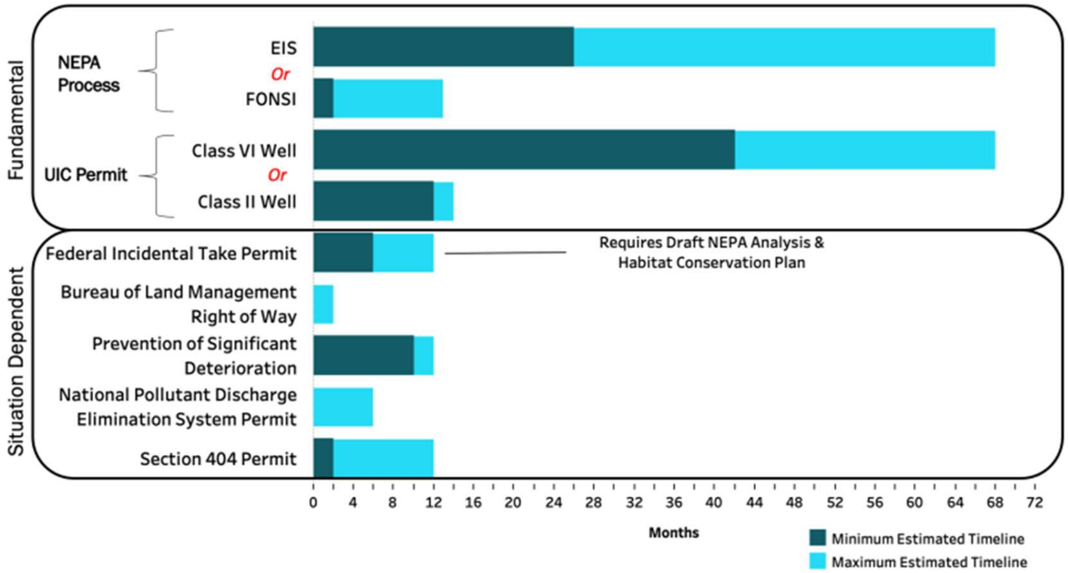
Developing and permitting enough CO_2 pipelines and geologic storage capacity to support EPA's proposal likely requires new policies and regulations that align the capture, transportation, sequestration, ongoing site care, and long-term liability transfer elements.

Permitting CCS projects is a highly uncertain process that can take years in ideal conditions (Figure 26).[55] The CCS value chain covers multiple sectors—each with different regulatory systems with little federal coordination—creating complex permitting needs.

An average CCS project consists of CO_2 capture facilities, processing plants, pipeline transport, and permanent geologic storage. CCS value chain complexity creates coordination costs and development risks that are disadvantageous to most developers, relative to other clean energy projects.[56]

Figure 26.

Estimated range of timelines for some CO_2 infrastructure regulatory and permitting processes



The process to permit CCS projects can take several months. It starts with the National Environmental Protection Act (NEPA) process, which is required when a project may significantly affect the environment. If the assessment finds no significant environmental impacts related to the project, an Environmental Assessment and Finding of No Significant Impact (EA/FONSI) is issued. Otherwise, an Environmental Impact Statement (EIS) is required. Projects must also obtain Underground Injection Control (UIC) permits according to whether they are Class VI (projects injecting CO_2 in deep geologic reservoirs) or Class II (projects injecting CO_2 for enhanced oil recovery—EOR). A Class II permit does not apply to the scenarios analyzed in this report, which need to obtain a Class VI permit instead. In addition, depending on the situation, CCS projects must also undergo other reviews to obtain a permit. Source: See first figure mention in text for sources.

EFI Foundation's analysis shows that state agencies may not be familiar with CCS and developers may not be familiar with the myriad permits required for a complex CCS project. Also, timelines for certain permitting steps—namely the Underground Injection Control (UIC) program Class VI application and the National Environmental Policy Act (NEPA) review process—are uncertain and potentially lengthy. Because CCS projects involve at least two processes (capture and storage) and sometimes transport as well, they can cross multiple regulatory jurisdictions.

In addition to 45Q, the IRA and IIJA include provisions that support CO_2 pipeline development, including $2.1 billion for low-interest loans and grants for CO_2 transportation and DOE authority to include support for CO_2 transport FEED studies. In May 2023, DOE announced $9 million in funding for three CO_2 pipeline network FEED studies in Wyoming, Louisiana, and Texas. DOE's $8 billion Regional Clean Hydrogen Hubs program will also likely include support for CO_2 transport infrastructure at one or more hubs.

As of June 2021, only two operational Class VI wells—both part of Archer Daniel Midland's CCUS project in Decatur, Illinois—had been permitted in the United States. It took nearly six years for the project to receive its permit to inject, a critical step to bringing a CCS facility online. CCS permitting is highly variable across the country, and numerous entities are involved in the process.[57] States have primary siting authority over CO_2 pipelines and set safety standards for intrastate pipelines. For pipelines that cross state lines, the federal Pipeline and Hazardous Materials Safety Administration sets safety standards governing CO_2 pipeline construction, maintenance, and operation.[58]

Box 1

Recent challenges to building CCS infrastructure

In early September 2023, the South Dakota Public Utilities Commission struck down an application to build a 1,300-mile carbon capture pipeline system that would connect five ethanol plants retrofitted with carbon capture. The commission said the project did not meet the statutory requirements of: 1) complying with applicable laws and rules, 2) not posing a threat of serious injury to the environment nor to the social and economic conditions of affected landowners, 3) not substantially impairing the health, safety or welfare of the inhabitants, and 4) not unduly interfering with future development by municipalities. [59]

Navigating the property and subsurface ownership rights is another major challenge for CCS projects. Property law governing ownership of pore space[k] varies drastically between states. Legislatures in North Dakota, Wyoming, and Montana have clarified this issue by vesting ownership of the pore space with the surface owner. However, in many states with suitable CO_2 storage sites, ownership remains ambiguous. Ownership and leasing of pore space on federal lands also remain uncertain. The mineral reservations granted on federal lands do not clearly extend to pore space, as the pore space itself is not "severable" from the subsurface, unlike oil and gas. While this timeline may shorten as more projects apply for Class VI permits, uncertainty is a challenge.

Clean Hydrogen Infrastructure

The hydrogen value chain consists of multiple production pathways, various modes of transport and storage, and dozens of potential end uses. Across each aspect of the value chain, varying levels of commercial readiness will shape near-term market development.

The United States has one of the largest hydrogen industries in the world, highly concentrated in a few regions and designed mostly to support the petrochemicals sector. No clean hydrogen is produced or consumed in the country. As of 2021, the United States had 25 hydrogen pipelines, collectively spanning 1,600 miles with four underground salt dome storage facilities in use or in development (Figure 27).[60,61]

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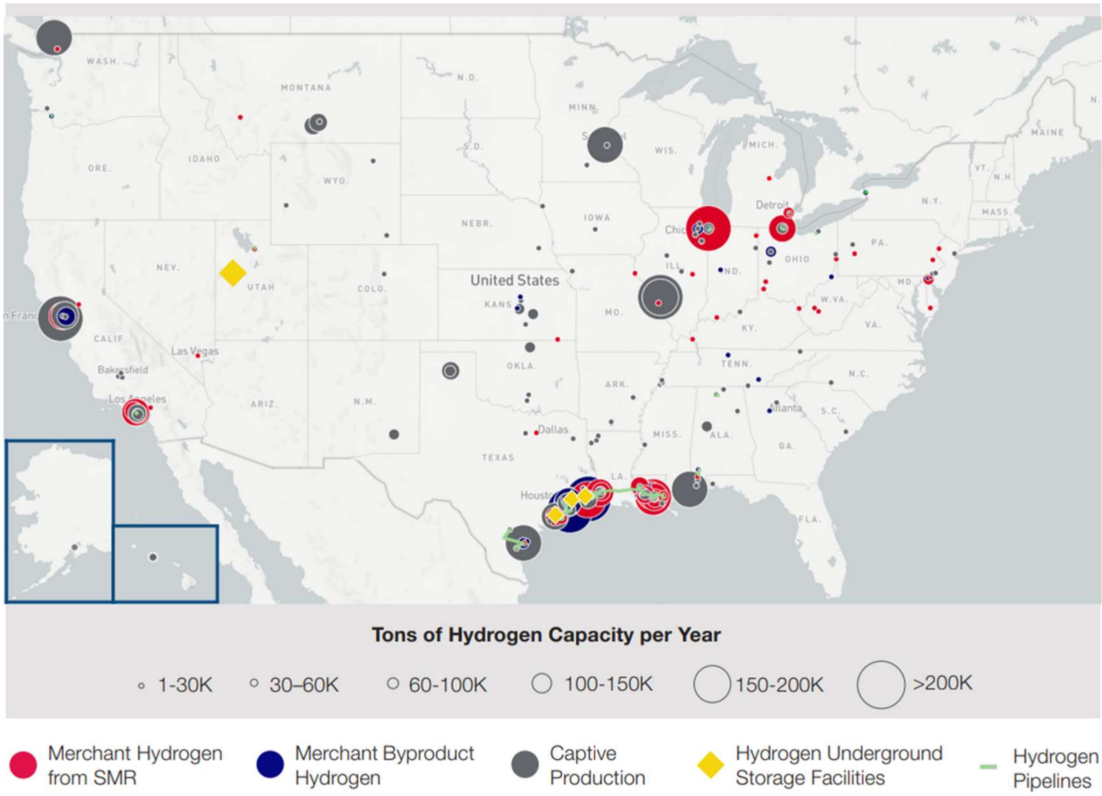
[k] Pore space is the microscopic empty space between particles of rocks or sand.

Figure 27.

Existing U.S. hydrogen infrastructure



Existing hydrogen infrastructure in the United States is concentrated in a few regions of the country, such as the Gulf Coast, California, and the upper Midwest. Hydrogen is produced to be consumed on-site ("captive" production) or to be sold to an offtaker ("merchant" production from steam methane reformation—SMR—of natural gas or as a byproduct). Besides production infrastructure, the map also shows the location of other existing hydrogen infrastructure, such as hydrogen pipelines and underground storage facilities. Source: See first figure mention in text for sources.

As of August 2022, the EFI Foundation has tracked 374 distinct clean hydrogen project announcements that cover many aspects of the value chain.[62] Notably, since EFI Foundation began tracking projects in June 2021, the number of announced projects increased nearly sevenfold, with a major jump following the announcement of the IIJA's H2Hubs program.

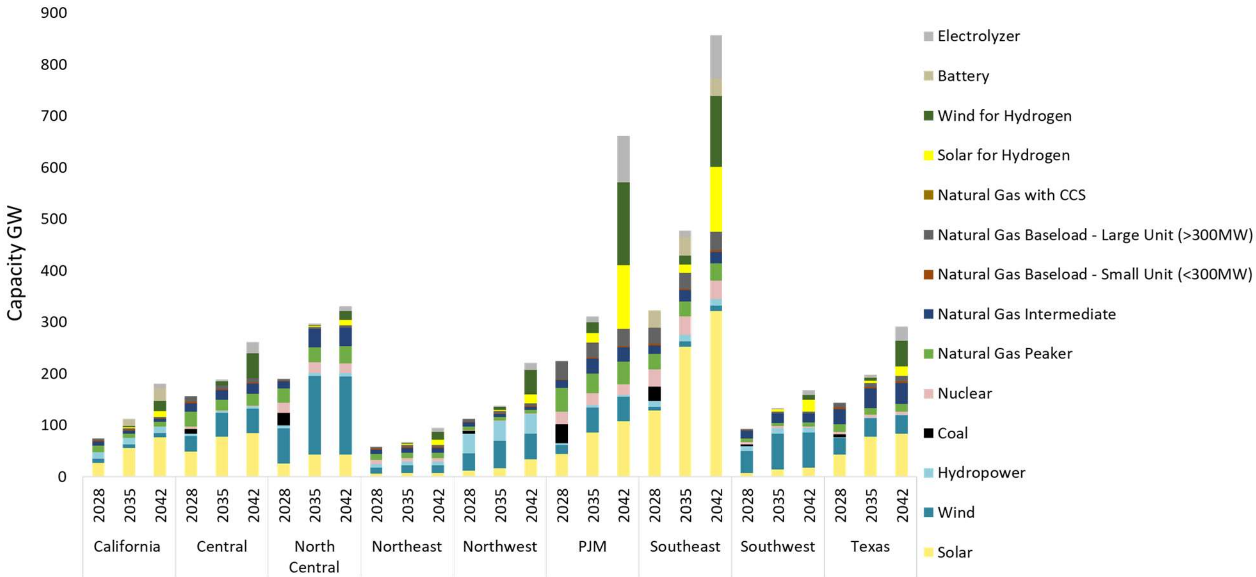
Modeling Results

In EFI Foundation's High H2 scenario, all coal is phased out by 2035, affecting certain regions more than others (Figure 28). The approach for covering that supply shortfall depends on each region's existing resources and the size and types of assets also impacted by EPA's proposal.

Solar capacity increases fivefold and wind increases threefold compared to today. Natural gas continues to play an important role, with capacity remaining flat through 2042. Major deployments of clean hydrogen infrastructure are needed as EPA's proposal requires 105 GW of hydrogen co-firing with natural gas by 2035 and 124 GW by 2042.

Figure 28.

Installed capacity by region in High H2 scenario

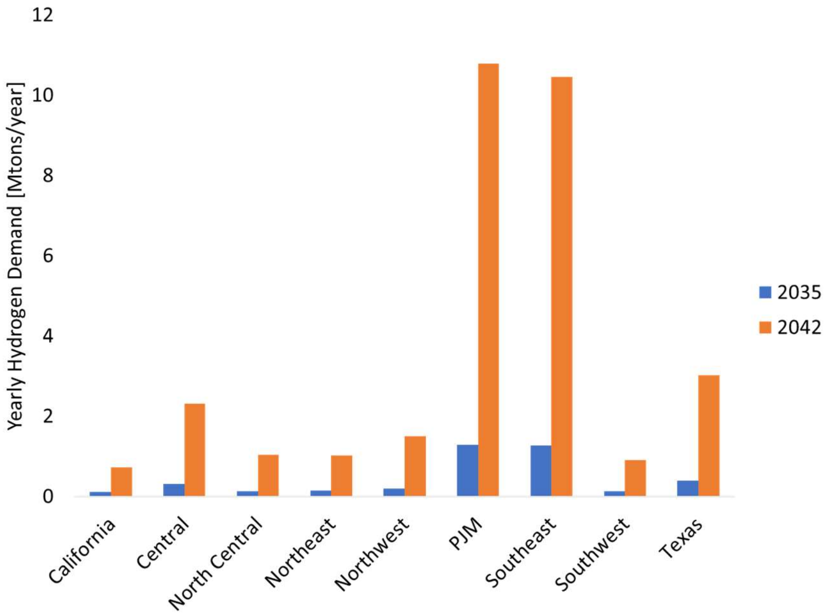


Coal power plants are phased out of the system by 2035 in the High H2 case. Renewables capacity increases to compensate, as does battery storage to provide reliability. Natural gas intermediate and base load power plants adopt clean hydrogen at a 30% rate by 2032; base load plants must ramp that value up to 96% by 2038. The observed increase in wind and solar capacity is also to produce the clean hydrogen demanded by these intermediate and base load plants. Source: EFI Foundation modeling analysis using SESAME tool.

In the High H2 scenario, U.S. hydrogen demand would grow from 4 Mt in 2032 to more than 32 Mt by 2042 (Figure 29). This massive spike in demand corresponds to EPA's proposal as all new and existing (300 MW and larger) base load units (50% CF or higher) adopted co-firing hydrogen by 30% by volume in 2032 and 96% by 2042 to comply with EPA's proposal, while all new intermediate load units employed 30% co-firing starting in 2032. As the results show, U.S. regions with a larger number of these assets demand more hydrogen than other regions.

Figure 29.

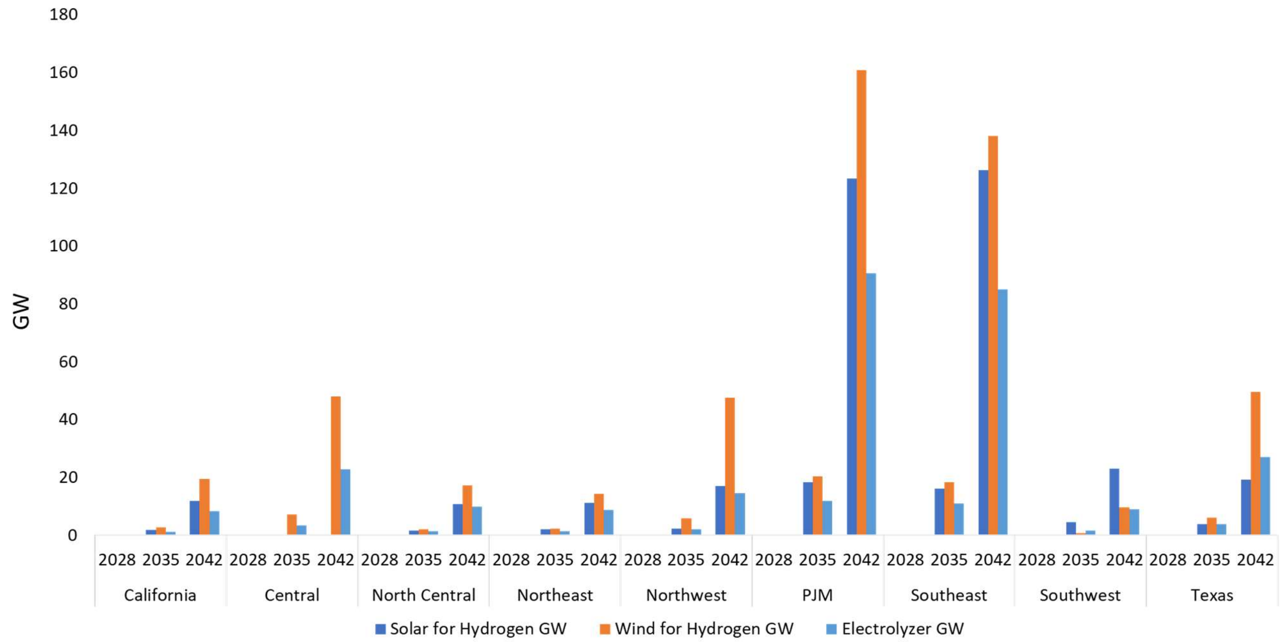
Hydrogen demand by region in High H2 case, 2035 and 2042



This graph shows the increase in hydrogen demand in the High H2 scenario, which occurs from intermediate and base load power plants that must blend natural gas with clean hydrogen to keep operating. Source: EFI Foundation modeling analysis using SESAME tool.

Large amounts of dedicated renewables (115 GW in 2035, 850 GW by 2042) are needed to power electrolyzers (capacities of 37 GW in 2035, 275 GW in 2042) for clean hydrogen production (Figure 30). To put this into context, there is about 230 GW of wind and solar capacity on the grid today. The electrolyzer capacity factors are a function of the renewable resources in each region.

Figure 30.
Installed capacities for hydrogen production in High H2 scenario

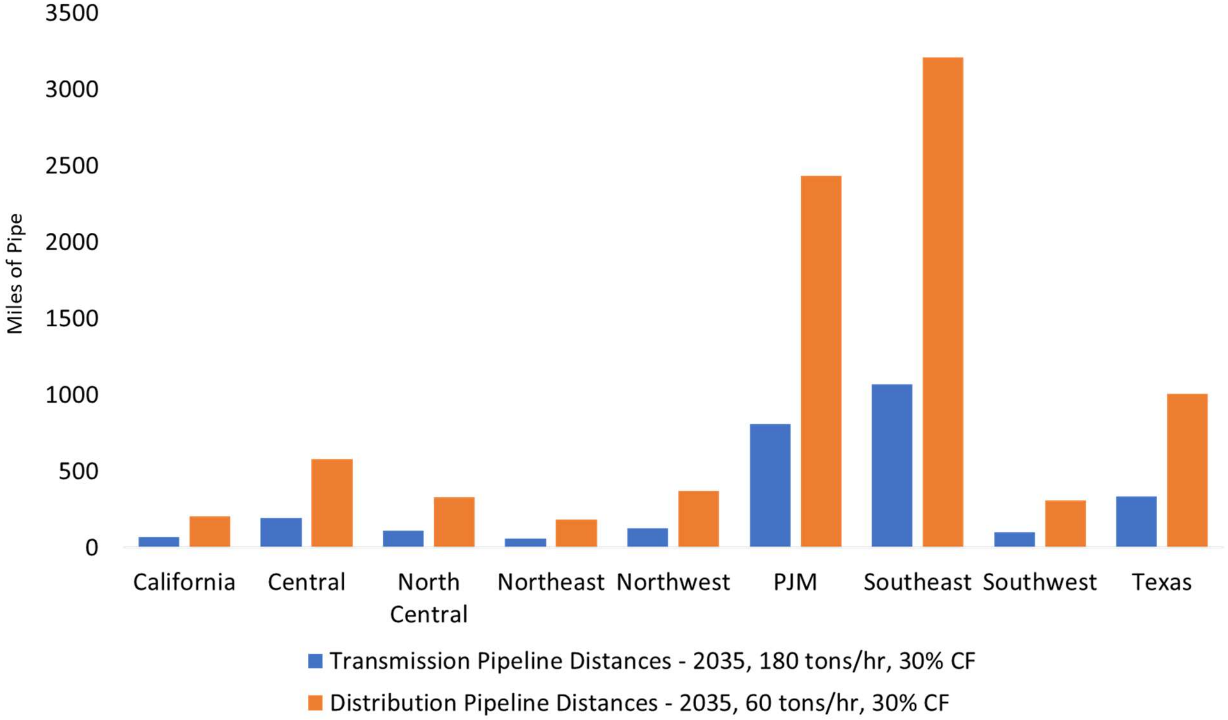


Electrolyzer capacity to produce clean hydrogen ramps up to fulfill demand in the PJM, Southeast, Texas, and Central regions. Both wind and solar are used in hydrogen production, depending on these resources' availability in each region. Source: EFI Foundation modeling analysis using SESAME tool.

There are many options for building out the storage and pipeline infrastructure for hydrogen. It was assumed that hydrogen cannot be piped between regions, recognizing some of the permitting challenges of building new energy infrastructure across state lines. Assuming there is access to large-scale storage (6,000 tons capacity each), such as salt domes, within each region, there would need to be roughly 30 storage sites by 2035 and more than 200 by 2042. There are four in operation or development today. Figure 31 shows the amount of pipeline needed if there was access to large-scale storage in 2035.

Figure 31.

Hydrogen pipeline miles by region in 2035, High H2 scenario



Thousands of miles of transmission and distribution pipelines need to be built nationwide in the High H2 scenario. PJM and the Southeast will experience the most hydrogen pipeline development. Source: EFI Foundation modeling analysis using SESAME tool.

For comparison, if only compressed tank storage (50 tons of capacity each) is available, the system would need more than 600 tanks by 2035 and more than 5,000 in 2042.

Box 2

Additional clean hydrogen infrastructure considerations

As the clean hydrogen industry scales, a major issue will be how early movers handle hydrogen transport and storage. According to DOE, offtakers not co-located with producers must evaluate the cost-effectiveness of hydrogen trucking (gaseous vs. liquid) for their particular use case and the extent to which newly built pipelines or retrofits will be possible.[63] Hydrogen can be distributed to power plants via trucking liquid or gaseous hydrogen, or through dedicated pipelines, or blended into existing natural gas systems. A project's solution for hydrogen delivery will depend on production schedule, distance and volume transported, and end-use requirements.

At small volumes (e.g., about 20 tons per day), hydrogen trucking can be one of the most cost-effective methods of transport. DOE estimates levelized costs of \$0.9-\$1/kg by 2030.[64] Hydrogen trucking requires relatively low CAPEX for the compressors and tube trailers, but offers very low transport capacity. This approach has a low barrier to market entry and can enable project development across the value chain. However, trucking may offer limited support for hydrogen co-firing at power plants because these facilities will depend on a highly reliable supply of relatively large volumes.

Many firms are exploring blending hydrogen into existing pipeline networks, usually in the natural gas system. This includes blending hydrogen into domestic natural gas pipelines at up to 20% by volume (2%-7% content by energy density), with a small number of demonstration projects up to 30%. The blending limits of hydrogen can be highly uncertain, driven by the age, size, materials, designs, and operations of the existing networks.[65] Moreover the costs of this approach are also highly variable.[66] While pipeline blending complements EPA's proposal, it may be difficult for gas-fired generators to rely on it for meeting the agency's proposed requirements of 30% co-firing by 2035 and 96% by 2038, without additional supplies from trucks or dedicated pipelines. Also, if the gas pipeline serves other industries, there will likely need to be additional facilities for separating and purifying hydrogen from natural gas, adding to project costs.

Dedicated hydrogen pipelines can move large volumes over long distances to achieve economies of scale (around $0.2-$0.5/kg at 600 tons per day[l]).[67] While pipelines offer the hydrogen supply reliability needed for many power generation projects, pipeline construction is time- and capital-intensive. EPA's proposal could create the stable, creditworthy offtakers needed to justify dedicated infrastructure buildout in some regions.

For generators that adopt the hydrogen co-firing strategy, they will likely need to develop new hydrogen storage to ensure their project has reliable access to hydrogen throughout the year. The costs of hydrogen storage vary greatly from $0.05/kg for geologic storage (i.e., salt domes) to up to $1/kg for compressed gas tank storage.[68] Regions outside of the Gulf Coast, where the current salt dome hydrogen storage is operating, may lack access to salt dome storage and would need to use other, costlier storage options.

Permitting Challenges

Developing and permitting new clean hydrogen projects can be a novel activity with complex regulatory jurisdictions (Figure 32).[69] Transporting hydrogen via dedicated pipelines is overseen by several federal agencies and a patchwork of federal statutes and regulations. At the local level, more entities get into the mix. The federal government regulates the economics and safety and security of hydrogen pipelines. Its role in siting and certification is focused on environmental regulations, such as the Endangered Species Act and the Clean Water Act, which may come into play depending on the location of the project.

The Surface Transportation Board, part of the U.S. Department of Transportation, regulates the rates, terms of service, and practices of interstate hydrogen pipeline carriers to ensure they are just, reasonable, and nondiscriminatory. Currently, for interstate natural gas pipelines, under Section 7(c) of the Natural Gas Act, companies must obtain a certificate of public convenience and necessity from the Federal Energy Regulatory Commission (FERC) to construct any facilities for natural gas transportation across state lines.

[l] Distributing 600 metric tons per day over 300 kilometers.

Figure 32.

Regulatory jurisdictions over hydrogen pipeline permitting in the Gulf Coast

	Federal	State
Fundamental	• Surface Transportation Board (STB/DOT): regulates the economic aspects of interstate hydrogen pipelines • DHS and TSA/PHMSA: regulate hydrogen pipeline safety	• Texas and state laws of any neighboring jurisdictions that the pipeline passes through: regulate pipeline siting, location, and certification • Texas Railroad Commission: pipeline compliance regulation
Situational	The following laws/agencies may be implicated: • Endangered Species Act • The National Historic Preservation Act • The Coastal Zone Management Act • The Clean Water Act • Permits from the U.S. Army Corps of Engineers • Federal Highway Administration	The following agencies may be implicated: • Texas Commission on Environmental Quality (TCEQ) • Texas Parks and Wildlife Department (TPWD)

Pipeline permitting in the Gulf Coast region must go through a matrix of federal and state regulations involving multiple agencies at both levels. Fundamental regulations are those that must be handled at the federal and state levels to properly permit a hydrogen pipeline. Situational regulations will apply based only on the particular circumstances or characteristics of individual projects, often as a result of geographic and environmental considerations. Source: See first figure mention in text for sources.

The IIJA created the H2Hubs program to address multiple challenges facing hydrogen infrastructure development. The IIJA calls for each hub to establish “a network of clean hydrogen producers, potential clean hydrogen consumers, and connective infrastructure located in close proximity.” DOE set several requirements for successful applications, including demonstrating deployment of regional hydrogen infrastructure and ensuring a balance between clean hydrogen production and consumption.

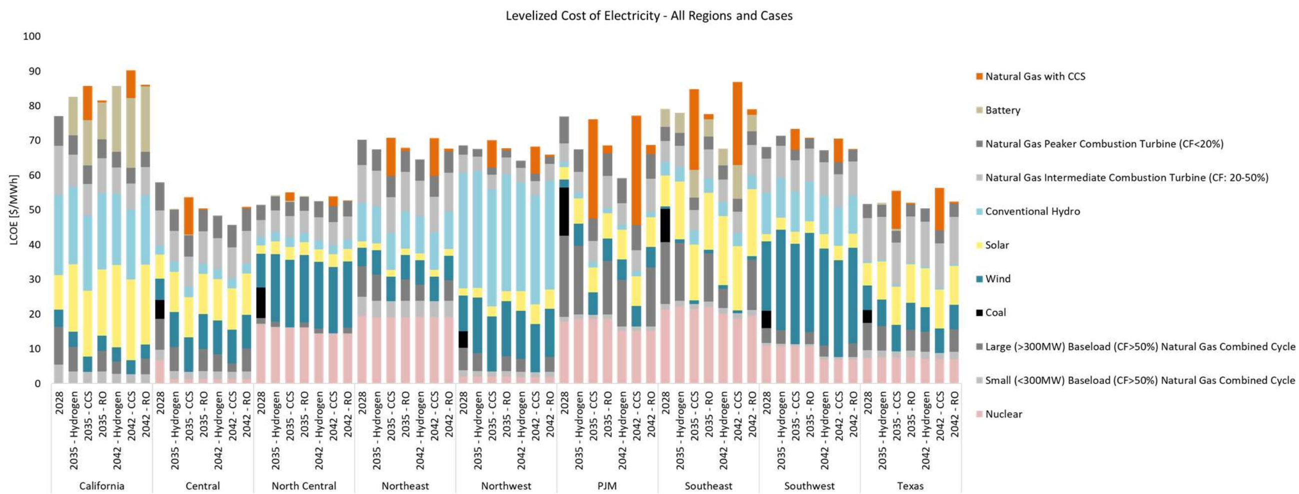
By design, regional clean hydrogen hubs will involve a broad constellation of projects and activities. Many of these will require permits and, in some cases, environmental impact statements before they can proceed. It may be difficult for hub participants and the broader industry to take advantage of the lessons learned from regional hubs as DOE expects the execution of these demonstration projects to take eight to 12 years.[70]

The proposed BSERs are not equally available across the country, leading to regional variation in system costs and net emissions benefits

BSER is a technology-based approach to reducing the electric sector's emissions. CCS and clean hydrogen are crucial decarbonization pathways that are also natural resource-dependent, and the ability to produce at scale and at low cost will differ by region. Regions with significant low-cost clean energy resources and geologic storage potential, for example, may be able to implement EPA's proposals more cost-effectively than regions with neither. EFI Foundation modeling of the LCOE across the three scenarios shows some of the regional disparities (Figure 33). Note the percent change in LCOE in some regions can be as high as 20% or as low as 15% in meeting the EPA proposal's requirements.

Figure 33.

Comparing LCOE [$/MWh] by region in High CCS, High H2, and High RO scenarios



This graph shows the contribution of each technology to electricity price, measured by the levelized cost of electricity (LCOE). As expected, the LCOE varies by scenario and region of the country according to the technologies that need to be deployed in each case studied and with the availability of local enabling infrastructure and resources. Source: EFI Foundation modeling analysis using SESAME tool.

EPA and other federal agencies can help mitigate some of the permitting uncertainty through robust federal-state engagement via the State Plans process, allowing states to propose their own optimal systems of emissions reduction that achieve the necessary environmental performance outlined by EPA's proposal. To further investigate the systemwide impacts of EPA's proposal, regional case studies were developed, supported by detailed modeling of the state's or region's energy system. Models were developed for the Carolinas, Michigan, and Pennsylvania because these states are in regions seemingly most impacted by the policy. Below are the results of the regional models and research to understand the executability and infrastructure requirements of EPA's proposal.

The Carolinas

Summary: EPA's proposal would have a significant impact on the energy systems of North Carolina and South Carolina. The region maintains one of the largest shares of large coal- and gas-fired generation that would be covered by the policy. While the Carolinas have substantial clean energy resources and policy commitments to support electricity decarbonization, the region would likely rely on the hydrogen co-firing and reduced operations options to comply with EPA's proposal, as there are limited resources for geologic storage for CCS. In the High H2 scenario, the Carolinas would demand one of the largest shares of clean hydrogen in the country. Without access to low-cost hydrogen storage (e.g., salt dome formations), the region may also have some of the highest CAPEX requirements.

Regional Modeling of EPA's Proposal

The Carolinas' economic profile and resource base are important considerations when analyzing options for compliance with EPA's proposed rules for fossil power plants. The region has abundant clean energy resources, ambitious decarbonization policies (including for the power sector), and a large industrial base to support the transition.

North Carolina plans to cut electricity emissions 70% by 2030 and reach carbon neutrality by midcentury.[71] It also has a statewide climate action plan, an interagency council on climate change, and a climate risk assessment and resilience plan.[72] Both North and South Carolina are among the top producers of nuclear electricity in the country. Solar generation also plays a major role in the region; North Carolina has one of the largest installed solar capacities in the United States. The region has one of the largest manufacturing sectors in the country, including motor vehicle assembly, chemicals, and food and beverage, among others.

To model EPA's proposal on the region, a similar approach was used for the nine EIA regions and the results for North and South Carolina were separated out Using the Annual Energy Outlook 2023 Reference Case as a baseline, modeling was done for the two states to ensure compliance with EPA's proposal while maintaining electric reliability in 2028, 2035, and 2042. Because the Carolinas have little to no access to geologic storage resources, according to the NATCARB database, it was assumed that the region would depend on hydrogen co-firing and/or reduced operations pathways to comply with EPA's proposal in 2038, 2035, and 2042.

In the two scenarios, EPA's proposal would likely drive all coal-fired generation off the system by 2035. This is aligned with existing strategies in the region.[73] Backfilling the lost generation in 2035 and 2042 will require a considerable increase in a mix of new resources. The modeling results show a need for nearly 70 GW of non-hydro renewables by 2035 and 100 GW by 2042. In the High H2 scenario, the Carolinas will need an additional 5 GW of wind and solar generation and 1.8 GW of new electrolysis to meet regional hydrogen demand by 2035. By 2042, nearly 80 GW of additional solar is needed and roughly 15 GW of new electrolysis. Hydro stays roughly flat, while new nuclear capacity increases only slightly (up by 0.3 GW). Gas-fired capacity will also increase, as 1.5 GW of new peaker capacity comes on line that is not subject to BSER requirements, and roughly 4 GW of intermediate load units are needed.

The High H2 case shows there will be 10.5 MTPA of hydrogen demand in the Southeast region in 2042, with nearly 10% of that demand in the Carolinas. The infrastructure requirements vary greatly, depending on the system configuration (e.g., a highly decentralized system or a hub). Each possible outcome has its own costs and feasibility.

Estimated annual CAPEX for the region is nearly $5.5 billion in 2035 and $22 billion in 2042. Solar costs are between $1.4 billion and $2.3 billion per year through 2042. Building the enabling hydrogen infrastructure represents the highest system costs after 2035. By 2042, hydrogen infrastructure costs include $7.4 billion for dedicated solar for hydrogen production, $3.7 billion for electrolyzers, and $1 billion for hydrogen storage.

It is assumed that only new wind and solar are used for hydrogen production, aligned with EPA's proposal of hydrogen LCA at 0.45 kg CO_2e/kg H_2. Because of the challenges of building new onshore wind in the region—in part because of the location of the resource and challenges navigating the Blue Ridge Mountains—solar accounts for most of the new renewable builds.

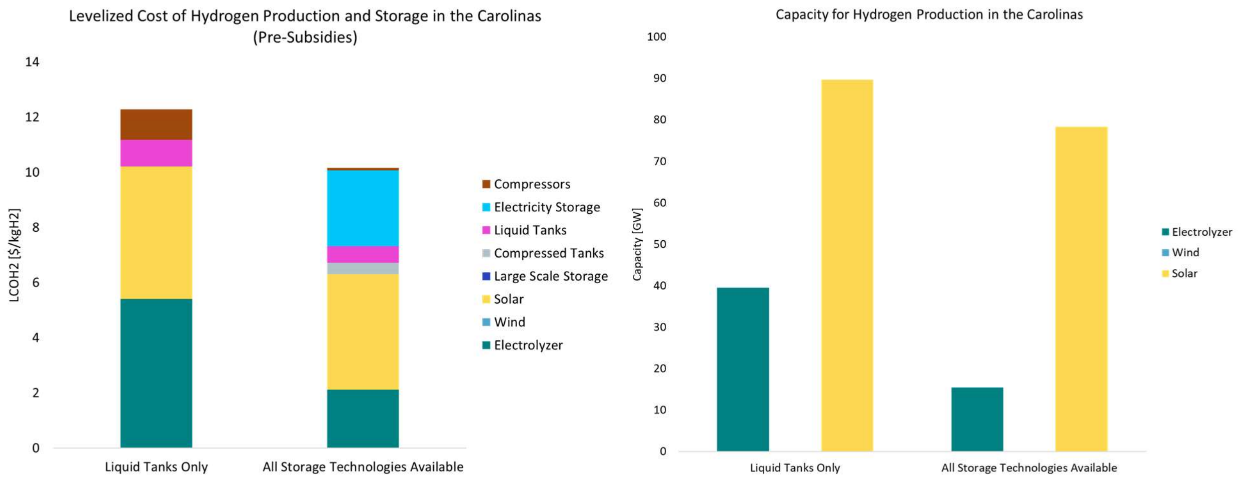
Because the region lacks access to low-cost, large-scale hydrogen storage (e.g., salt domes), the modeling presents alternative technology scenarios for storage. In one example, the Carolinas rely only on liquid tank storage, which requires large electrolyzer deployment by 2042 and a measurable cost for the compression to convert hydrogen to a liquid. The average electrolyzer CF in this example is around 24% and the levelized costs of hydrogen are around $12/kg (pre-subsidy) (Figure 35).

Alternatively, the Carolinas could employ multiple storage technologies, including liquid and compressed tank storage, resulting in a lower cost of delivered hydrogen, around $10/kg by 2042. This system includes large-scale (25 GW) battery storage, which increases the capacity factor of the electrolyzers, lowering the cost of delivered hydrogen. The average electrolyzer CF is 63% in this example.

In either configuration, these renewables-only hydrogen production systems can claim the full 45V tax credit subsidy ($3/kg), lowering the levelized costs to $9/kg and $7/kg in 2042, respectively, for liquid tank storage or multiple storage technologies, though much higher than EPA's assumed cost of $0.5/kg (Figure 34).

Figure 34.

High H2 case for the Carolinas, delivered hydrogen costs and system requirements in 2042

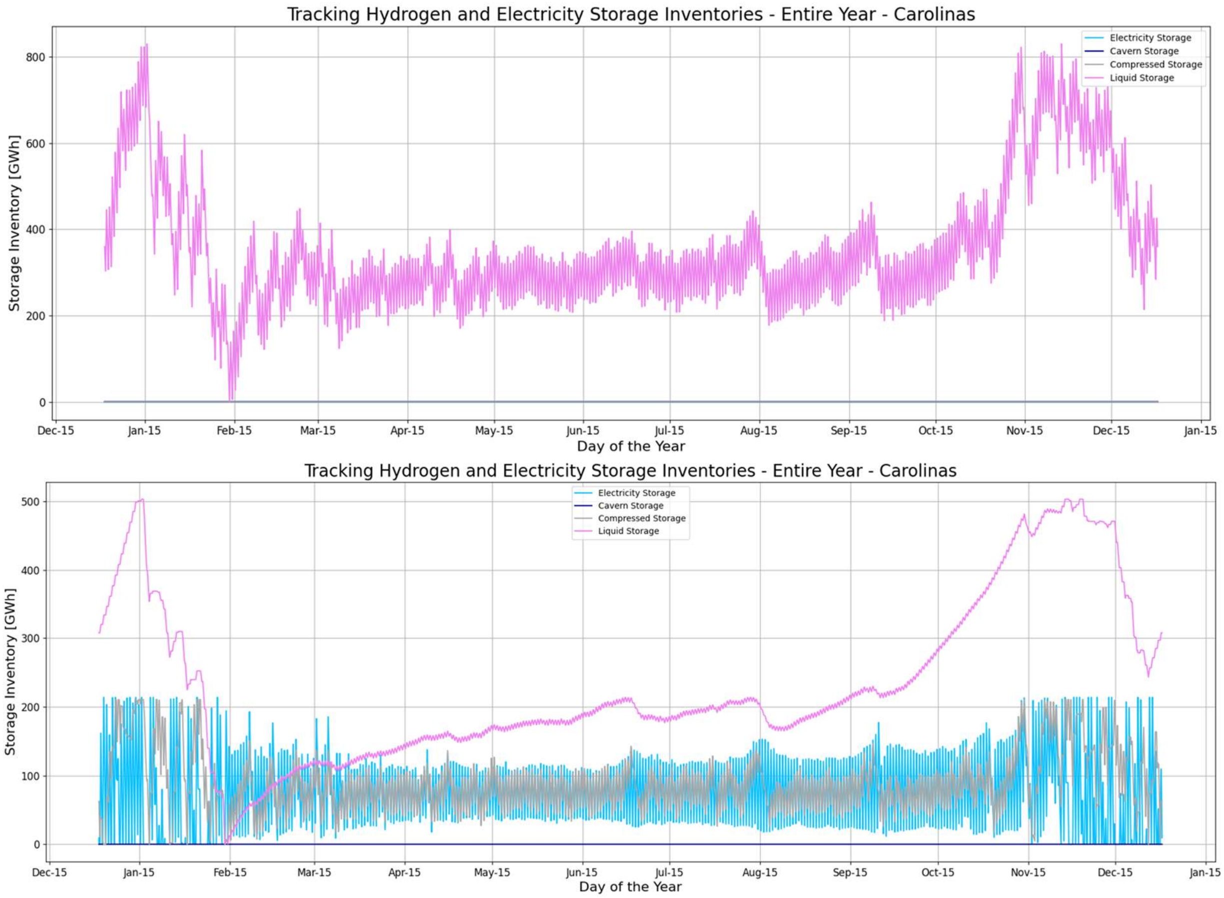


Because the Carolinas lack access to low-cost, large-scale hydrogen storage (e.g., salt domes), liquid tanks or a mix of liquid and compressed tanks ("all storage") are available for storage. The latter option results in a lower levelized cost of hydrogen (LCOH, left) because of battery storage, which increases the capacity factor of electrolyzers, lowering the cost of delivered hydrogen. The right side of the graph shows the electrolyzer and renewable capacity needed to produce clean hydrogen. Wind power does not contribute to clean hydrogen production in the Carolinas. Source: EFI Foundation modeling analysis using SESAME tool.

SESAME modeling accounts for hourly changes in supply and demand since the generators using hydrogen need highly reliable supplies throughout the year. Figure 35 shows how the two hydrogen storage examples operate throughout the year to ensure hydrogen demand is met in 2042. In both examples, renewables-heavy systems need to draw on more storage in the winter months, requiring large storage builds in the late fall.

Figure 35.

Daily and seasonal hydrogen storage flows



Hydrogen storage needs vary according to whether liquid or both liquid and compressed hydrogen storage are in place. In both examples, renewables-heavy systems need to draw on more storage in the winter months, requiring large storage builds in the late fall. Source: EFI Foundation modeling analysis using SESAME tool.

For comparison, in the High RO case for the Carolinas, natural gas capacity remains roughly flat, while gas-fired generation from intermediate load units increases by more than 20% to help cover the shortfall from the large units that reduced operations below 50% CF to lower their policy compliance costs. The costs of the hydrogen are much higher on a levelized basis than in the High H2 case. Delivered hydrogen costs (unsubsidized) are around \$11/kg in 2035 and \$8/kg in 2042.

Michigan

Summary: EPA's proposal would encourage Michigan to close its remaining coal facilities. The region maintains one of the largest manufacturing sectors and a large labor force to drive implementation. While Michigan has the resources and capabilities to support CCS and clean hydrogen, the state is prioritizing its hydrogen activities and ambitions. The modeling focuses on the High H2 scenario.

<u>Regional Modeling of EPA's Proposal</u>

Michigan has one of the largest manufacturing-based economies in the country, employing the largest share of workers in the motor vehicles and parts manufacturing sectors. Other core economic sectors include fabricated metal products, chemicals, food and beverage products, and plastics. Michigan also has a notable mining sector, focused primarily on non-fuel mineral products such as quarried limestone, iron ore, stone, sand and gravel, lime, copper, and cobalt.[74],

Michigan set targets to reduce economywide emissions 28% by 2025 and 52% by 2030 and to achieve carbon neutrality by 2050.[75] The state also finalized a Healthy Climate Plan in 2022 outlining the strategy to reduce emissions in different sectors through midcentury.[76] Michigan has the Council on Climate Solutions, a nongovernmental advisory body to facilitate interagency climate collaboration, and the Michigan Saves green bank.[77] In 2016, Michigan set a Renewable Portfolio Standards (RPS) target of 15% by 2021 and 35% by 2025.[78] Michigan is also ranked 11th in the nation for its grid modernization plan and efforts to date.[79]

To model EPA's proposal on the region, a similar approach was used for the nine EIA regions, and the results in Michigan were separated out. Using the *Annual Energy Outlook 2023 Reference Case* as a baseline, modeling was done for Michigan to ensure compliance with EPA's proposal while maintaining electric reliability in 2028, 2035, and 2042. Michigan has clean hydrogen initiatives underway across many sectors, including electricity.[80] It was assumed in the modeling that the state would depend on hydrogen co-firing to comply with EPA's proposal in 2038, 2035, and 2042.

In this scenario, EPA's proposal would likely drive 6 GW of coal-fired generation off the system by 2035. This is aligned with the governor's current plans.[81] Backfilling the lost generation will require a hefty increase in a mix of new resources. The modeling results show a need for nearly 30 GW of non-hydro renewables by 2035. In the High H2 scenario, Michigan will need an additional 1.8 GW of wind and solar generation and 0.6 GW of new electrolysis to meet regional hydrogen demand by 2035. By 2042, nearly 14 GW of additional wind and solar is needed and roughly 4.7 GW of new electrolysis. Hydro and nuclear stay roughly flat, while 2.5 GW of new intermediate load capacity comes on line.

The High H2 case shows there will be 10.8 MTPA of hydrogen demand in the PJM region in 2042, with nearly 5% of that demand in Michigan. The infrastructure requirements vary greatly, depending on the system configuration (e.g., a highly decentralized system or a hub). Each possible outcome has its own costs and feasibility.

Estimated annual CAPEX for the region is nearly $1.17 billion in 2035 and $4.15 billion in 2042. Solar costs are $0.25 billion per year through 2042. Building the enabling hydrogen infrastructure represents the highest system costs after 2035. By 2042, hydrogen infrastructure costs include $0.25 billion for dedicated solar and $1.6 billion for dedicated wind for hydrogen production, $1.1 billion for electrolyzers, and $0.3 billion for hydrogen storage.

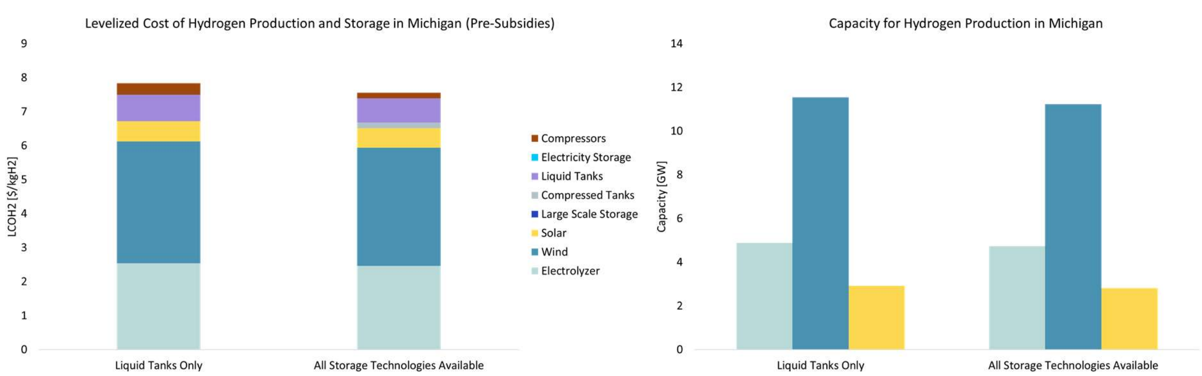
It is assumed that only new wind and solar are used for hydrogen production, aligned with EPA's proposal of hydrogen LCA at 0.45 kg CO_2e/kg H_2. Because the amount of low-cost, large-scale hydrogen storage (e.g., salt domes) is uncertain, the modeling presents alternative technology scenarios for storage. In one example, Michigan relies only on liquid tank storage, which requires large electrolyzer deployment by 2042 and a measurable cost for the compression to convert hydrogen to a liquid. The average electrolyzer CF in this example is around 52% and the levelized costs of hydrogen costs are around $8/kg (pre-subsidy) (Figure 36).

Alternatively, Michigan could employ multiple storage technologies, including liquid and compressed tank storage, resulting in a slightly lower cost of delivered hydrogen, around $7.5/kg by 2042. This system includes 2.5 GW of battery storage, which increases the CF of the electrolyzers, lowering the cost of delivered hydrogen. The average electrolyzer CF is 54% in this example.

In either configuration, these renewables-only hydrogen production systems can claim the full 45V tax credit subsidy ($3/kg), lowering the levelized costs to $5/kg and $4.5/kg in 2042, respectively, though much higher than EPA's assumed cost of $0.5/kg.

Figure 36.

High H2 case for Michigan, delivered hydrogen costs and system requirements in 2042



Large-scale hydrogen storage (e.g., salt domes) is uncertain in Michigan, which, in turn, has the option to store clean hydrogen in liquid or both liquid and compressed storage tanks. The second option results in a lower LCOH because *battery storage increases the capacity factor of electrolyzers. The graph on the right details the renewable resources (wind and solar) and electrolyzer capacities to produce clean hydrogen in Michigan. Source: EFI Foundation modeling analysis using SESAME tool.*

Pennsylvania

Summary: EPA's proposal could have a significant impact on Pennsylvania's energy system, likely driving the closure of the state's remaining coal generation and prompting considerable uptake of clean hydrogen or possibly CCS. The region maintains one of the largest manufacturing sectors and a large labor force to drive implementation. While Pennsylvania has the resources and capabilities to support CCS and clean hydrogen, the state is prioritizing its hydrogen activities and ambitions. The modeling focuses on the High H2 scenario.

Regional Modeling of EPA's Proposal

Pennsylvania has one of the largest state economies in the country.[82] About 20% of the state's GDP comes from activity in the finance, insurance, real estate, rental, and leasing sectors. The largest energy-intensive industries contributing to Pennsylvania's GDP include natural gas and oil extraction and mining, metals and machinery manufacturing, chemical products, and agriculture and food processing.[83] The state functions as one of the primary suppliers of natural gas, coal, and refined petroleum products to the East Coast. Pennsylvania is the third-largest electricity producer in the United States and the largest producer in the PJM Regional Transmission Organization.

Pennsylvania has set targets to reduce greenhouse gas emissions economywide 26% by 2025 and 80% by 2050.[84] This mandate was set in 2019, and the state released its Climate Action Plan in 2021 to outline pathways to achieve these targets.[85] The state also has a Climate Change Advisory Committee, a non-governmental advisory body to facilitate interagency climate bureaucracy collaboration.

In 2004, Pennsylvania passed an RPS target of 18% by 2021 and currently ranks 17th in the nation for its grid modernization efforts.[86,87] Pennsylvania is also a member of the Regional Greenhouse Gas Initiative (RGGI), a carbon pollution pricing mechanism adopted by a dozen states in the Northeast United States.[88]

To model EPA's proposal on Pennsylvania, a similar approach was used for the nine EIA regions, and the results for Pennsylvania were separated out. Note that in EIA's subregions, Pennsylvania includes parts of New Jersey and Delaware. Using the *Annual Energy Outlook 2023 Reference Case* as a baseline, modeling was done for Pennsylvania to ensure compliance with EPA's proposal while maintaining electric reliability in 2028, 2035, and 2042. It was assumed in the modeling that the state would depend on hydrogen co-firing to comply with EPA's proposal in 2038, 2035, and 2042.

In this scenario, EPA's proposal would likely drive 11.5 GW of coal-fired generation off the system by 2035, reflecting recent trends in the state.[89] Backfilling the lost generation will require a major increase in a mix of new resources. The modeling results show a need for nearly 33 GW of non-hydro renewables by 2035. In the High H2 scenario, Pennsylvania will need an additional 16.5 GW of wind and solar generation and 5 GW of new electrolysis to meet regional hydrogen demand by 2035. By 2042, nearly 145 GW of additional wind and solar is needed and roughly 45 GW of new electrolysis. Hydro and nuclear stay roughly flat, while 1.5 GW of new intermediate load capacity comes on line.

The High H2 case shows there will be 10.8 MTPA of hydrogen demand in the PJM region in 2042, with nearly 10% of that demand in Pennsylvania. The infrastructure requirements vary widely, depending on the system configuration (e.g., a highly decentralized system or a hub). Each possible outcome has its own costs and feasibility.

Estimated annual CAPEX for the region is nearly \$5 billion in 2035 and \$34 billion in 2042. Solar costs are \$0.5 billion per year through 2042. Building the enabling hydrogen infrastructure represents the highest system costs after 2035. By 2042, hydrogen infrastructure costs include \$6 billion for dedicated solar and \$11.4 billion for dedicated wind for hydrogen production, \$11 billion for electrolyzers, and \$3 billion for hydrogen storage.

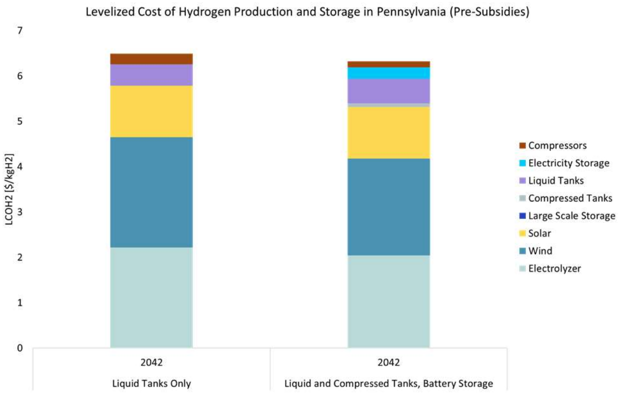
It is assumed that only new wind and solar are used for hydrogen production, aligned with EPA's proposal of hydrogen LCA at 0.45 kg CO_2e/kg H_2. Because the amount of low-cost, large-scale hydrogen storage (e.g., salt domes) is uncertain, the modeling presents alternative technology scenarios for storage. In one example, Pennsylvania relies only on liquid tank storage, which requires large electrolyzer deployment by 2042 and a measurable cost for the compression to convert hydrogen to a liquid. The average electrolyzer CF in this example is around 60%, and the levelized costs of hydrogen costs are around \$6.5/kg (pre-subsidy) (Figure 37).

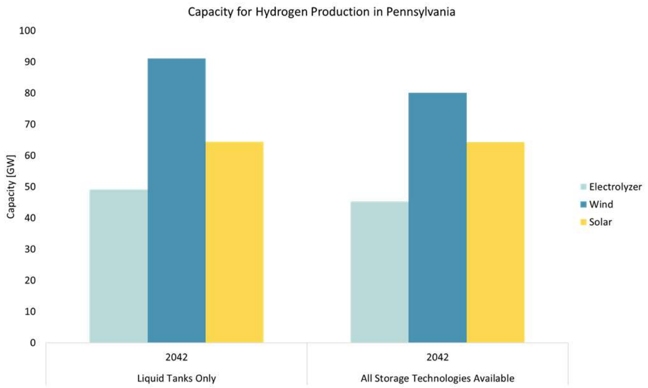
Alternatively, Pennsylvania could employ multiple storage technologies, including liquid and compressed tank storage, resulting in a slightly lower cost of delivered hydrogen, around \$6.3/kg by 2042. This system includes 2.5 GW of battery storage, which increases the CF of the electrolyzers, lowering the cost of delivered hydrogen. The average electrolyzer CF is 65% in this example.

In either configuration, these renewables-only hydrogen production systems can claim the full 45V tax credit subsidy (\$3/kg), lowering the levelized costs to \$3.5/kg and \$3.5/kg 2042, respectively, though much higher than EPA's assumed cost of \$0.5/kg.

Figure 37.

High H2 case for Pennsylvania, delivered hydrogen costs and system requirements in 2042





Large-scale clean hydrogen storage is also an uncertainty in Pennsylvania. As such, liquid and both liquid and compressed tank hydrogen storage are options to store clean hydrogen in the state. As in the previous examples, the combination of storage techniques results in lower LCOH. The graph on the right displays electrolyzer and renewables' capacity to produce clean hydrogen in Pennsylvania. Source: EFI Foundation modeling analysis using SESAME tool.

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