Hydrogen in the Power Sector: Limited Prospects in a Decarbonized Electric Grid

An assessment of the potential role of low-carbon hydrogen for decarbonizing the power sector

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CLEAN AIR TASK FORCE

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Executive Summary

This paper investigates the following questions related to the potential role that clean hydrogen can play in decarbonizing the power sector:

1. Is burning hydrogen in power plants technically feasible?
2. What infrastructure is required to use hydrogen in the power sector and what could that infrastructure cost?
3. Does burning low-carbon hydrogen reduce lifecycle greenhouse gas emissions from power plants?
4. What are the economics of using low-carbon hydrogen in the power sector and how does it compare to alternative technologies?

On technical feasibility, this paper finds that hydrogen could be used to generate electricity, whether it be in retrofitted gas plants or new hydrogen-burning turbines. However, the practical realization of hydrogen use for electricity is likely highly dependent on developing high-cost hydrogen storage and transport infrastructure. For green hydrogen, an additional concern is the very large amounts of renewable electricity and land that would be needed for large scale production due to the low efficiency of the hydrogen power supply chain, which would consume three-fourths of all clean electricity that is stored and generated via hydrogen.

Beyond technical challenges, the use of hydrogen for clean electricity generation, even when produced only from surplus electricity and used infrequently for load following, is likely to remain very costly. Whether compared to generation using hydrogen produced from variable renewable resources and storage or from reformed natural gas with carbon capture, lower cost options for load following likely include current generation and batteries as well as higher capacity factor zero carbon dispatchable sources such as advanced geothermal, nuclear, gas with carbon capture and, potentially in the future, long duration energy storage, that could be used to minimize the need for high-cost clean hydrogen use in power.

While accurate cost comparisons between hydrogen and other technologies will need to be done via system analyses within specific jurisdictions, hydrogen does not readily appear to be a cost-effective solution for either bulk power production or load following and storage. Accordingly, this paper indicates that extensive use of low-carbon hydrogen for power requires closer scrutiny. It also confirms CATF's initial analysis that clean hydrogen production should be prioritized for use in industry and heavy transportation – to decarbonize existing hydrogen production in industrial applications and to decarbonize heavy transportation.

Key Takeaways

1. Combustion turbines and power plants will likely be technically capable of burning a pure stream of hydrogen gas, although more research and development (R&D) will be required to overcome technical challenges.

2. Geological hydrogen storage coupled with dedicated hydrogen transport pipelines will need to be in place to enable large-scale use of hydrogen in power plants. The cost and deployment challenges of building this infrastructure remain uncertain but are likely high.

3. The use of electrolytic hydrogen made with clean electricity (with a low but nonzero carbon intensity) in a power plant can reduce lifecycle emissions by 90% compared to unabated natural gas, though at a large cost premium. Hydrogen produced from clean electricity and used in power generation has a round trip efficiency (RTE) of almost 24%; three-quarters of the clean electricity used is lost in the process. Therefore, dedicated electrolytic hydrogen for use in power generation and produced from an electricity grid that is not largely decarbonized has opportunity costs and could use up a lot of clean electricity that could be used to decarbonize other electricity demand.

4. Electrolytic hydrogen produced from surplus electricity in a largely decarbonized grid can play a role in grid balancing as a form of long duration energy storage (LDES). However, there should be an evidence-based approach that examines the tradeoffs of using electrolytic hydrogen as a storage medium within the entirety of the power system design, evaluates alternatives, and optimizes for criteria such as total system cost, reliability, minimal community impacts, and land-use needs. This includes evaluating whether it is more cost effective to reduce the need for storage to begin with via higher capacity factor clean generation technologies such as geothermal, nuclear, and gas with carbon capture and/or additional transmission.

5. Using low-carbon hydrogen derived from natural gas reforming with carbon capture amplifies the upstream carbon footprint of the natural gas supply chain compared to alternative solutions. As a result, emissions reductions using low-carbon hydrogen derived from natural gas compared to power generation from unabated natural gas range from 20% to 73%, with an average reduction of 50% based on estimated natural gas supply chain emissions in the U.S.[1]

6. The levelized cost of storage (LCOS) via electrolytic hydrogen produced from surplus clean electricity is estimated to be in the range of USD 350 – USD 470 per MWhe while the levelized cost of electricity (LCOE) from a power plant operating on low carbon hydrogen from an autothermal reforming (ATR) hydrogen plant is estimated to be in the range of USD 300 – USD 400 per MWhe. In comparison, battery storage LCOS today is estimated at USD 150-170 per MWhe, though current battery storage is largely limited to four hours. Clean firm generation costs that could minimize the need for long duration energy storage and hydrogen use in power range from USD 70-130 per MWh_e.

7. The lifecycle carbon abatement cost of electrolytic hydrogen produced from surplus clean electricity is estimated at USD 360 per tonne of CO_2e while that of hydrogen from natural gas and carbon capture is estimated at USD 450 per tonne of CO_2e.

1 The analysis was based on natural gas supply chain emissions in the U.S. which range from 0.4% volume production methane leakage (U.S. Northeast) to 6.13% (U.S. Permian). While certain locations globally can have slightly lower or higher methane leakage rates, a global study found that leakage rates in most regions fall between 0.5% and 3% by volume.

Introduction

Renewable electricity has seen explosive growth in the past decade and is projected to account for a dominant share of electricity generation in the future decarbonized grids as numerous countries push to decarbonize their power systems. Nonetheless, several governments, industry bodies, and utilities have also been exploring a potential role for hydrogen to decarbonize the power system, specifically as a perceived 'clean' fuel-based and dispatchable replacement for their natural gas power plant fleet.

The superficial logic is simple: replace a polluting fuel with one that does not emit carbon dioxide. Unfortunately, the reality is not so simple. Unlike natural gas, hydrogen is not a primary source of energy and needs to be manufactured with associated direct and indirect emissions. Clean hydrogen (also referred to as "low-carbon hydrogen"), produced from natural gas with carbon capture or from clean electricity using water electrolysis, is still scarce and currently accounts for only 0.1% of global hydrogen production, mainly due to challenging economics and undeveloped supply chains. While supply may increase in the future, hydrogen's physical properties make it more difficult to transport and store than natural gas, which adds to the complexity of hydrogen as a viable fuel for decarbonizing the power sector.

Hydrogen can, however, play a more limited role as a form of long duration energy storage if it is produced only or primarily during periods of surplus clean electricity supply and in the context of a largely decarbonized grid. During such periods, renewable generation can be diverted to operate electrolyzers that produce hydrogen that can be stored for use by clean, firm backup generators in future periods when the supply of renewable energy is insufficient to meet power system demands. However, associated technical, logistical, and economic challenges must be overcome for this to be a viable pathway, and alternative pathways that minimize the need for hydrogen storage via other storage technologies or clean firm generation options should be evaluated. This paper accordingly proposes a more nuanced and realistic view of clean hydrogen in decarbonizing the power system.

In addressing the questions posed in the executive summary, we assume that clean hydrogen used for power generation would be locally produced. Imported clean hydrogen and ammonia from distant suppliers would have even less favorable economics and higher supply chain emissions intensity and is thus largely ignored in this paper.

Hydrogen Production Overview

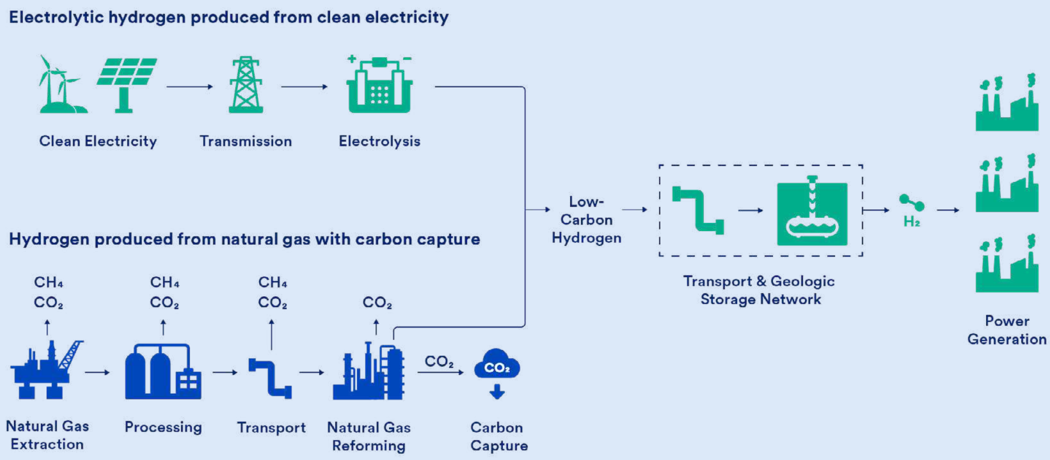
Virtually all dedicated hydrogen production today uses fossil fuel feedstocks. Globally, about 59 million metric tons or ‘tonnes’ (MT) of hydrogen are produced annually from natural gas, using steam methane reforming. Another 20 MT per year are produced from coal, using gasification, with the rest of global hydrogen production coming from oil and electricity.

Clean hydrogen generally refers to either electrolytic hydrogen generated using clean electricity or hydrogen produced from natural gas with carbon capture (though there are additional hydrogen production methods). Electrolytic hydrogen is produced through water electrolysis, a process that splits water molecules into its constituent hydrogen and oxygen molecules. Provided the electricity that powers the electrolysis process is low carbon, the resulting product is typically considered clean hydrogen.

Hydrogen may also be considered clean if it is produced by reforming natural gas and capturing the resulting carbon emissions. The carbon intensity of this production pathway depends on the portion of carbon emissions that are captured and the upstream methane and CO_2 emissions from the natural gas supply chain.

Figure 1 shows the pathways for low-carbon hydrogen use in power generation.

Figure 1: Supply chain options for low-carbon hydrogen in power generation



SECTION 1

Is burning hydrogen in power plants technically feasible?

The combustion of hydrogen in turbines is not technically novel. The refining, petrochemical, and steel industries have significant experience with the combustion of hydrogen-rich gas mixtures for heat and power generation. Combusting hydrogen can produce more NOx emissions than combusting natural gas due to hydrogen's higher flame temperature. Increasing the percentage of hydrogen combusted also has several technical challenges that must be addressed in parallel with NOX emissions, such as flashback, stability, increased volumetric flowrates, and ramping and load-change impact, but those challenges can be overcome as more projects are built. While the physical and chemical properties of hydrogen create technical challenges when burning a pure hydrogen stream, current commercial offerings from the major turbine original equipment manufacturers (OEMs) can operate on up to 30%–100% ratios of hydrogen/natural gas (by volume).

Turbines, however, are just one part of a power plant. Existing natural gas power plants would require several adjustments to facilitate the use of hydrogen, as shown in Figure 2.

KEY TAKEAWAY 1

Combustion turbines and power plants will likely be technically capable of burning a pure stream of hydrogen gas, although more research and development (R&D) will be required to overcome technical challenges.

Figure 2: Modifications to enable existing natural gas combined cycle (NGCC) power plants to operate on hydrogen

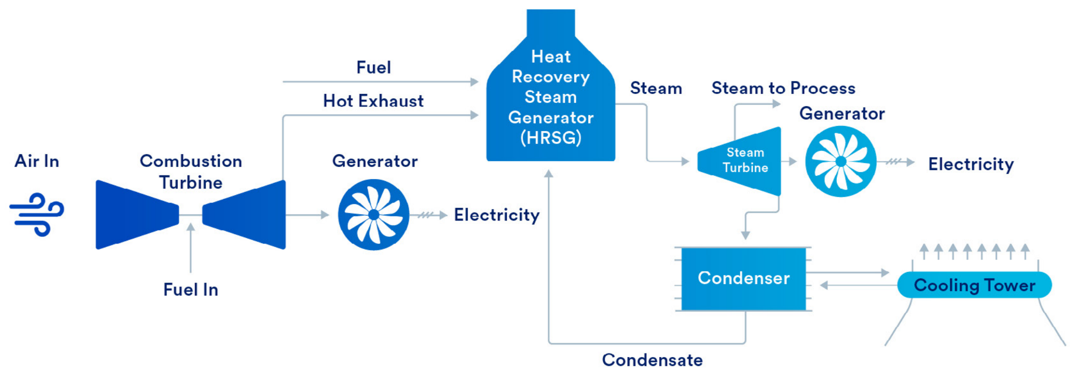
Potential reevaluation of material selection due to hydrogen embrittlement and other corrosion mechanisms

NOx control through Selective Catalytic Reduction

Reconfiguration of HRSG section due to change in exhaust gas composition and flow rate (dew point adjustment...)

Fire & Safety system overhaul due to hydrogen's wider flammability range

Installation of purging lines to avoid hydrogen entrapment in enclosed spaces



Understanding infrastructure requirements for hydrogen storage

Dedicated hydrogen pipelines would be required in addition to potential geologic storage for large volumes

Changing valves and seals in turbine area to ensure containment due to hydrogen's higher diffusivity

Potential fuel blending skids required for blending natural gas and hydrogen

Overhaul of burner management system to accommodate modified fuel / air mixture characteristics such as flame speed

SECTION 2

What infrastructure is required to use hydrogen in the power sector and what could that infrastructure cost?

The biggest challenge of operating power plants on hydrogen will be the storage and delivery of sufficient volumes of clean hydrogen to the plant. Hydrogen has different physical and chemical properties compared to natural gas; notably, its volumetric energy density is approximately one-third that of natural gas. Therefore, three times the volume of hydrogen is needed to store the same amount of energy as a given volume of natural gas at similar temperatures and pressures, and approximately three times the compression energy is required for hydrogen to deliver the same amount of energy compared to an equivalent volume of natural gas. This complicates the use of existing natural gas infrastructure for transporting hydrogen as existing pipelines need to be larger or operate at a higher pressure to deliver the same amount of energy. To increase its volumetric energy density and enable more efficient handling, hydrogen gas is typically compressed to pressures up to 700 times that of atmospheric conditions. Tank volumes for transporting and storing compressed gaseous hydrogen, however, are generally limited to several hundred kilograms (kg) and are insufficient for sustained periods of power plant operations. Alternatively, hydrogen can be liquefied and stored under cryogenic conditions in complex spherical tanks[2], however, this approach entails significant energy inputs as well as high capital and operating costs.

Table 1: Physical properties of hydrogen (IEA 2019)

Property	Hydrogen	Comparison
Density (gaseous)	0.089 kg/m^3 (0°C, 1 bar)	1/10 of natural gas
Density (liquid)	70.79 kg/m^3 (-253°C, 1 bar)	1/6 of natural gas
Boiling point	-252.76°C (1 bar)	90°C below LNG
Energy per unit of mass (LHV)	120.1 MJ/kg	3x that of gasoline
Energy density (ambient cond., LHV)	0.01 MJ/L	1/3 of natural gas
Specific energy (liquified, LHV)	8.5 MJ/L	1/3 of LNG
Flame velocity	346 cm/s	8x methane
Ignition range	4-77% in air by volune	6x wider than methane
Autoignition temperature	585°C	220°C for gasoline
Ignition energy	0.02 MJ	1/10 of methane

Notes: cm/s = centimeter per second; kg/m^3 = kilograms by cubic meter; LHV = lower heating value; MJ = megajoule; MJ/kg = megajoules per kilogram; MJ/L = megajoules per liter

2 The largest spherical cryogenic hydrogen tank designed and built can store approximately 300 tons of liquid hydrogen.

In the U.S., natural gas power plants generally do not have dedicated onsite natural gas storage. Instead, the U.S. uses general purpose natural gas storage reservoirs. Gas plants rely on "line-packing," where gas transmission and distribution system operators increase pressure in the extensive pipeline network and distribution headers to move natural gas to end users. A power plant planning to operate on hydrogen, by contrast, does not have an existing hydrogen transmission network nor can the existing natural gas simply be used for hydrogen transmission and distribution, which means that the plant developers will also need to consider the costs and other permitting, siting, and development challenges associated with adding the hydrogen transmission infrastructure.

Outside of the U.S., some gas power plants located in coastal areas of Japan and South Korea do have onsite capability to store liquefied natural gas (LNG), as shown in Figure 3. Considering hydrogen power plants' anticipated role for backup in a weather-dependent power system, thousands of tonnes of hydrogen storage will be required to supply individual power stations.[3]

Given the challenges of storing hydrogen,[4] the most sensible option for the cost-effective storage of large volumes of hydrogen may be underground seasonal hydrogen storage (USHS) with a dedicated transmission network connecting the power stations. Currently, however, only four underground hydrogen storage facilities are in operation worldwide—three of them located on the U.S. Gulf Coast in Texas. Cumulatively, the U.S. facilities store approximately 15,000 tonnes of hydrogen in underground salt domes, a quantity sufficient to supply approximately 0.005% (five thousandths of one percent) of current U.S. power generation. These storage facilities are connected by 1,600 miles of pipeline to refineries and petrochemical plants, which require hydrogen for various process applications.

KEY TAKEAWAY 2

Geologic hydrogen storage coupled with dedicated hydrogen transmission pipelines would be necessary to enable large-scale use of hydrogen in power plants. The cost and deployment challenges of building this infrastructure remain uncertain but are likely high.

Figure 3: Joetsu Thermal Power Station, Joetsu City, Niigata Prefecture, Japan

Source: JERA

3 A 100MW simple cycle plant would consume approximately 2700 tonnes of hydrogen to run at 100% for a period of two weeks.

4 This paper does not examine the possibility of storing hydrogen derivatives such as ammonia or methanol in the context of long duration energy storage since power generation from these chemicals has not been extensively investigated or is still at low technology readiness levels.

SECTION 3

Does burning low-carbon hydrogen reduce *lifecycle* greenhouse gas emissions from power plants?

The combustion of hydrogen in power plants generates water vapor as its only direct by-product and can reduce greenhouse gas (GHG) stack emissions to zero in theory if effective NOx and N_2O emissions controls are in place.[5] However, upstream emissions—primarily from hydrogen production, but potentially also from energy requirements for hydrogen transport, storage, and handling—must be considered. Since the intention of using hydrogen to fuel power plants is primarily driven by potential climate benefits, the full scope of the resulting lifecycle emissions, or reductions thereof, must be thoroughly investigated. This means rigorously accounting for all carbon dioxide and incremental methane emissions generated throughout the full hydrogen supply chain.

Electrolytic Hydrogen

The emissions associated with the production of electrolytic hydrogen are directly tied to the carbon intensity of the electricity used for the electrolysis process. If 100% of the power needed to operate electrolyzers comes from clean electricity sources such as geothermal, hydropower, nuclear, wind, and solar, then hydrogen production's direct emissions would be 0 kg CO_2e/kg H_2 produced. However, this leaves out some additional indirect upstream emissions (for example to manufacture, install, and maintain solar panels or wind turbines). Therefore, in this report, we will use a lifecycle emissions value of 1kg CO_2e/kg hydrogen produced from clean electricity to account for the infrastructure and supply chain emissions associated with these clean sources.[6]

However, using electrolytic hydrogen to decarbonize power generation is not necessarily an effective approach to reduce emissions in the power sector due to the inefficiency and opportunity cost of using clean electricity to produce electrolytic hydrogen.

To understand why, one must consider the round-trip efficiency of using electrolytic hydrogen for power generation, where RTE is defined as the percentage of electricity input into a system that is later retrieved.

Extensive work by Clean Air Task Force and others highlights the need for rigor in tracing and quantifying the emissions characteristics of electricity used for electrolytic hydrogen production. Without such rigorous requirements, producing hydrogen via electrolysis can result in emissions significantly higher than the traditional hydrogen production pathway of unabated natural gas reforming, which has a carbon intensity of around 11 kg CO_2e/kg H_2. For instance, using electricity with a carbon intensity equivalent to that of the average U.S. grid (376 kg CO_2e/MWh_e) for electrolysis will produce hydrogen with a carbon intensity of 20 kg CO_2e/kg H_2—or almost twice that of unabated natural gas reforming. If this carbon intensive hydrogen were then used for power production, the carbon intensity of the power generated (962 kg CO_2e/MWhe) would be approximately three times as high as that from unabated natural gas combustion in a typical combined cycle plant and roughly equivalent to that of a coal-fired power plant.

5 This paper does not consider the global warming potential of hydrogen leakage into the atmosphere which will further undermine the case for using hydrogen as a fuel to decarbonize the power sector.

6 Direct emissions from clean sources of electricity such as hydro, geothermal, nuclear, solar, and wind are 0 kg CO_2e/MWh. However, the infrastructure and supply chain emissions for these sources can contribute to the carbon intensity of electrolytic hydrogen. The 1 kg CO_2e/kg H_2 used in this study is equivalent to using electricity with a lifecycle emissions of 18.5 kg CO_2/MWh assuming 54kWh of electricity consumption for every 1 kg H_2 produced.

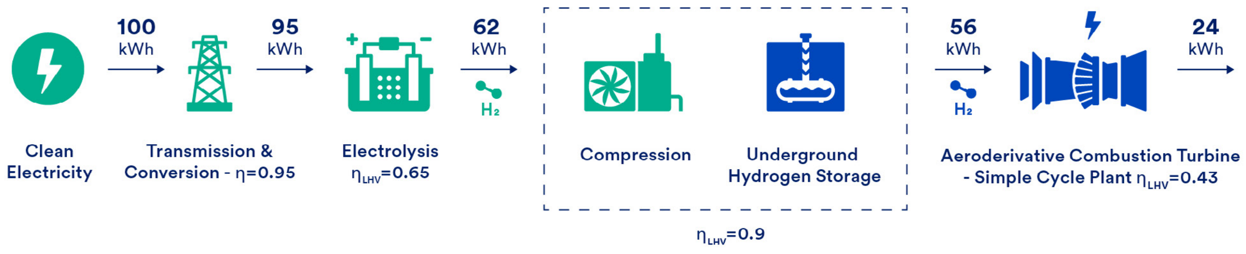
Figure 4 shows that the RTE for electrolytic hydrogen that is combusted in a power generation turbine can be around 24%. In other words, 76% of the clean electricity input is 'lost' along the supply chain. In a grid that is not already largely decarbonized, four units of clean electricity *that could otherwise displace four units of carbon-intensive electricity* will instead be used to deliver one unit of clean electricity from clean hydrogen, thereby losing three precious units of clean electricity.

Moreover, the use of renewable electricity to generate hydrogen is extremely land and capital intensive. For instance, to generate sufficient hydrogen to run a 418MW combined cycle plant at baseload operations, one would require 1.7GW of electrolyzers and approximately twice the capacity of electricity generation (~3.5 GW) from a combination of solar and wind and a capital investment of almost USD 8 billion not to mention extensive land use and transmission infrastructure. The capital invested just to generate the electrolytic hydrogen would exceed capital required for the combined cycle plant by a factor of 10 which is clearly not a financially sustainable proposition to decarbonize the power sector.

KEY TAKEAWAY 3

The use of electrolytic hydrogen made with clean electricity (with a low but nonzero carbon intensity) in a power plant can reduce lifecycle emissions by 90% compared to unabated natural gas though at a large cost premium. Hydrogen produced from clean electricity and used in power generation has a round-trip efficiency of 24%; three-quarters of the clean electricity used is lost in the process. Therefore, dedicated electrolytic hydrogen for use in power generation and produced from an electricity grid that is not fully decarbonized has opportunity costs could use up a lot of clean electricity that could be used to decarbonize other electricity demand.

Figure 4: System efficiency of electrolytic hydrogen use in power generation in a simple cycle plant[7]



7 Simple cycle plant has a net plant heat rate (NPHR) of 8805 BTU/kWh. The net plant efficiency decreases at lower loads. Electrolysis efficiency also decreases at lower loads and can be negatively impacted by rapid cycling. Generating power from electrolytic hydrogen in a combined cycle power plant can improve the RTE from 24% to 31% but does not meaningfully alter the conclusion of this section. Similarly, fuel cells can be used to generate electricity but do not affect the findings on the dedicated use of electrolytic hydrogen for power generation.

Electrolytic Hydrogen Production from Surplus Clean Electricity

The climate-beneficial role that electrolytic hydrogen might play in a decarbonized power system is that of grid balancing: clean hydrogen could be produced by operating electolyzers using surplus clean electricity during periods of high renewable energy availability. Instead of dedicated electrolytic hydrogen production for decarbonizing power generation, the hydrogen could act as a storage medium for surplus clean electricity. This functionality could be planned as part of the overall power system design. In practice, it might be necessary to build renewables capacity to exceed peak demand so surplus electricity supply will generate sufficient electrolytic hydrogen to be used for power generation during periods of low power supply from renewables.

While the need for long-duration energy storage (LDES) may be unavoidable if power system planners rely exclusively on weather-dependent generation sources, and while electrolytic hydrogen production may be a technically feasible choice for providing LDES, numerous questions must still be addressed to validate the viability of this approach for any particular power system:

1. Have other power system portfolios with clean firm dispatchable power that would reduce the need for LDES been considered and evaluated?
2. Where is the clean electricity curtailment happening and does it match with the location of potential hydrogen power plants? What are the system cost trade-offs of locating hydrogen production and hydrogen turbine closer to further away from electricity curtailment and load?
3. Where is the hydrogen stored and how would it be transported to end users?
4. What is the business model of the electrolysis facility given the intermittent nature of curtailment?
5. How will the electrolysis facilities be sized to balance their ability to capture surplus electricity with facility utilization?
6. Does the hydrogen produced from surplus clean electricity cover the demands of power plants over periods when there is a seasonal mismatch between supply and demand?
7. What is the increased requirement for renewable system capacity build above peak demand and do reasonable estimates of land use allow for it?
8. What are the economics for hydrogen production and subsequent electricity production? If assuming free surplus electricity, how certain are the conditions of surplus electricity given competing demands from electrified heating and transport, data center load growth, and other demand growth?
9. What are the implications of using hydrogen storage on total system cost and tariffs for the consumers in comparison to alternative portfolios? Would customers tolerate these costs?
10. What is the scale of expected curtailment and have all options for mitigation been evaluated?
11. Have other LDES options been considered?

KEY TAKEAWAY 4

Electrolytic hydrogen produced from surplus electricity in a largely decarbonized grid can play a role in grid balancing as a form of LDES. However, there should be an evidence-based approach that examines the tradeoffs of using electrolytic hydrogen as a storage medium within the entirety of the power system design to evaluate alternative portfolios with lower LDES needs and optimize for criteria such as total system cost, reliability, minimal community impacts, and land-use needs.[8] This includes evaluating whether it is more cost effective to reduce the need for storage to begin with via higher capacity factor clean generation technologies such as geothermal, nuclear, and gas with carbon capture and/or additional transmission.

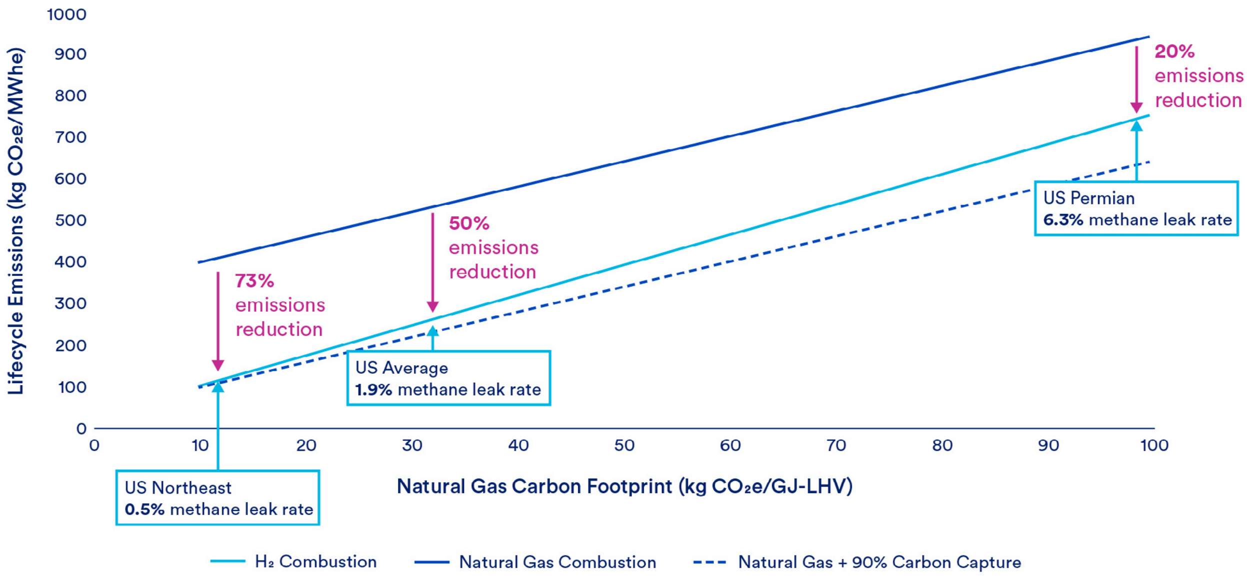
8 The topic of electrolytic hydrogen's impact on land use is further explored in this study.

Hydrogen from Natural Gas with Carbon Capture

If hydrogen is produced via natural gas reforming with a high rate of carbon capture, its lifecycle emissions primarily originate from the upstream activities in the natural gas supply chain, including extraction, processing, and transportation. Methane, a potent GHG, may be released directly to the atmosphere due to leaks or equipment venting; emissions can also result from incomplete combustion when methane is flared or used as a fuel. Upstream methane losses during extraction and transportation depend on a variety of factors including the geology of the gas field being developed, operational practices, and the length of the transmission pipelines. These emissions are difficult to measure, but the leak rate for natural gas delivered in the United States is estimated to vary from 0.5% to more than 6.3%. Per unit of energy, this corresponds to an upstream carbon footprint of 12–97 kg CO_2e/GJ at the lower heating value (LHV) of natural gas.

In addition, the combustion of natural gas in compressor stations during extraction, processing, and transmission produces CO_2 emissions. Figure 5 shows how upstream emissions from the natural gas supply chain affect lifecycle emissions for power generation in a combined cycle plant burning low-carbon hydrogen produced using auto-thermal reforming with a 94% carbon capture rate[9] for various natural gas carbon footprints.[10] These emissions are then compared to those from unabated power generation from natural gas combustion in a combined cycle power plant[11] (with the same natural gas carbon footprint).

Figure 5: Lifecycle emissions from electricity generation in a combined cycle plant using hydrogen produced from natural gas with carbon capture as the fuel vs. using unabated natural gas as the fuel



9 Operating parameters can be obtained from IEAGHG report 2022-07. The carbon intensity of the electricity used for this process is 18.5 kg CO2/MWh representative of a clean source of electricity.

10 The natural gas carbon footprint is calculated from the upstream methane leak rates during production and transmission and the CO_2 fuel supply chain emissions (flaring, transmission, and processing). The U.S. Northeast with 0.4% production methane leak rate has a natural gas footprint of 11.6 kg CO_2e/GJ_{LHV}. The average U.S. methane leak rate of 1.8% has a natural gas footprint of 32.8 kg CO_2e/GJ_{LHV} using the Global Warming Potential of 83 for methane (GWP-20). Methane leak rates from a 350km transmission pipeline are also included in the carbon intensity calculations.

11 Combined cycle multi-shaft 1083MW combined cycle plant with a 6370 BTU/kWh heat rate. Economic parameters are obtained from the Energy Information Administration's Annual Energy Outlook 2023.

In the case where total upstream methane emissions for delivered gas are based on a 0.5% leak rate (U.S. Northeast), estimated lifecycle emissions for hydrogen production total 2.4 kg CO_2e/kg H_2. Combusting this hydrogen in a combined cycle power plant yields lifecycle emissions of 112 kg CO_2e/MWhe. For comparison, the lifecycle emissions for unabated natural gas combustion in a combined cycle power plant are 413 kg CO_2e /MWhe assuming the same upstream natural gas emissions. High upstream methane emission leakage rates tend to dominate the lifecycle emissions from electricity generation such that, when natural gas is sourced from the U.S. Permian Basin, lifecycle emissions for power generation using low-carbon hydrogen are only 20% lower than for generation using unabated natural gas.

KEY TAKEAWAY 5

Using low-carbon hydrogen derived from natural gas reforming with carbon capture amplifies the upstream carbon footprint of the natural gas supply chain compared to alternative solutions. As a result, emissions reductions using low-carbon hydrogen derived from natural gas compared to power generation from unabated natural gas range from 20% to 73%, with an average reduction of 50% based on estimated natural gas supply chain emissions in the U.S.

SECTION 4

What are the economics of using low-carbon hydrogen in the power sector and how does it compare to alternative technologies?

To address this question, we consider the two main pathways for producing low-carbon hydrogen: natural gas reforming with carbon capture and water electrolysis using clean electricity.

Levelized Production Costs of Hydrogen

Electrolytic Hydrogen

As demonstrated in Section 3, the dedicated production of clean hydrogen via electrolysis for use as a power plant fuel is unlikely to yield an effective decarbonization outcome. As such, our analysis will shift to electrolytic hydrogen generated from surplus weather-dependent electricity and produced in a power system that is purpose-built to use hydrogen as a form of LDES.

Electrolytic hydrogen production cost estimates are more difficult to calculate, as they will mainly be influenced by the price of the electricity used to generate the hydrogen and the capacity factor of the electrolysis production facilities. As previously stated, this likely means building renewable resources that exceed peak demand such that the surplus electricity supply will generate sufficient electrolytic hydrogen to be used during periods of low power supply from renewables. Note that surplus electricity conditions do not necessarily mean that electrolytic hydrogen generation should assume free electricity input (see the box below). In contrast to producing hydrogen from natural gas with carbon capture, electrolytic hydrogen production must be planned as part of the overall power system design. Developers will want to optimize the sizing of electrolysis facilities to produce electrolytic hydrogen at the lowest cost. A large electrolysis facility can capture a higher portion of surplus electricity but will operate at full capacity less often, which is disadvantageous from a cost perspective, whereas a smaller facility won't always be able to utilize all available surplus electricity but will tend to operate at a higher capacity factor on average. Table 2 shows a heatmap of the levelized cost of hydrogen production as a function of electrolyzer capacity utilization and electricity price. This analysis assumes the levelized cost to produce electrolytic hydrogen is USD 3/kg with an additional cost of USD 1/kg for hydrogen transportation and storage.

Table 2: Levelized cost of electrolytic hydrogen production (2022 USD/kg) as a function of electricity price and electrolyzer capacity factor

Source: Internal CATF modeling[12]

		Electrolysis Facility Capacity Factor				
		10%	20%	30%	40%	50%
Levelized Cost of Electricity ($/MWh)	$ -	$6.7	$3.4	$2.3	$1.7	$1.4
	$10/MWh	$7.2	$3.9	$2.8	$2.2	$1.9
	$20/MWh	$7.7	$4.4	$3.3	$2.7	$2.4
	$30/MWh	$8.2	$4.9	$3.8	$3.2	$2.9

12 The real pre-tax weighted average cost of capital (WACC) is assumed to be 8%. We further assume a total installed cost (TIC) of $950/kW for PEM electrolyzers, with system-specific energy consumption of 48.1 kWh_{AC}/kg hydrogen, where energy consumption increases linearly up to 10% higher than start-of-run conditions after 60,000 hours of stack operation. Stack replacement is calculated at 10% of TIC. Annual operating expenditures are assumed to be 3% of TIC. We assume that hydrogen is delivered at 30 barg at the battery limit of the electrolysis facility. Costs exclude hydrogen storage and transportation costs.

Pricing Surplus Electricity

Surplus electricity is generally assumed to have no economic value and is hence often assigned a price of USD 0/MWh_e. However, this is a simplification that warrants scrutiny as there are many scenarios in which there might not be significant excess clean electricity to sustain hydrogen production or where the cost of electricity to hydrogen generation facilities may not be zero even when wholesale prices are zero or negative.

The first reason why clean electricity will likely not be “free” is the need for clean electricity suppliers to secure contracts with customers to finance their projects. Consider a power system that often has an oversupply of renewable electricity that results in many hours with zero or negative wholesale electricity prices. Under such conditions, wholesale market revenue for renewable electricity generators would be low or zero, especially considering generation that is correlated to other renewable generators. In such a market environment, clean electricity developers would likely rely on purchase agreements (PPAs) or contracts for difference (CfDs) with customers who need certainty in clean electricity supply to mitigate the risk of low revenues. Thus, the price of clean electricity for a hydrogen production facility would likely be set by contract prices and not spot market prices, even under conditions of surplus supply. In these cases, the price of clean electricity will never be zero. Today, estimates of cost to provide clean firm electricity by pairing intermittent renewables with energy storage technologies, such as batteries, are above \$100/MWh_e. This estimate does not consider wholesale transmission charges that would further add to electricity costs.

The second reason why clean electricity will likely not be “free” is the need for hydrogen facilities to secure a reliable source of clean electricity. Without contracting, it would also be risky for a hydrogen production developer to make a business case for a production plant based solely on forecasting cheap clean energy surplus conditions over the lifetime of the electrolyzer asset. The power system will have many competing demands for clean electricity that will likely limit how much surplus electricity is available at very low prices in the future. Energy storage arbitrage, electric vehicle charging, electrified heating and cooling, electrified industry demand, data center demand, and direct air capture will all be competing to secure cheap, surplus electricity. Expanded transmission will also reduce pockets of surplus, decreasing price disparities between regions. Faced with such risk, a hydrogen plant developer would likely seek contracts for a portfolio of firm clean resources to ensure clean electricity supply. These contracts that are likely to be priced well above \$50/MWh_e.

As such, it is unlikely large-scale long-lived assets will be developed on the basis of forecasted “free” surplus electricity prices. As such, electrolytic hydrogen generation costs should be based on an estimated cost of clean electricity to match expected hourly load of the facility.

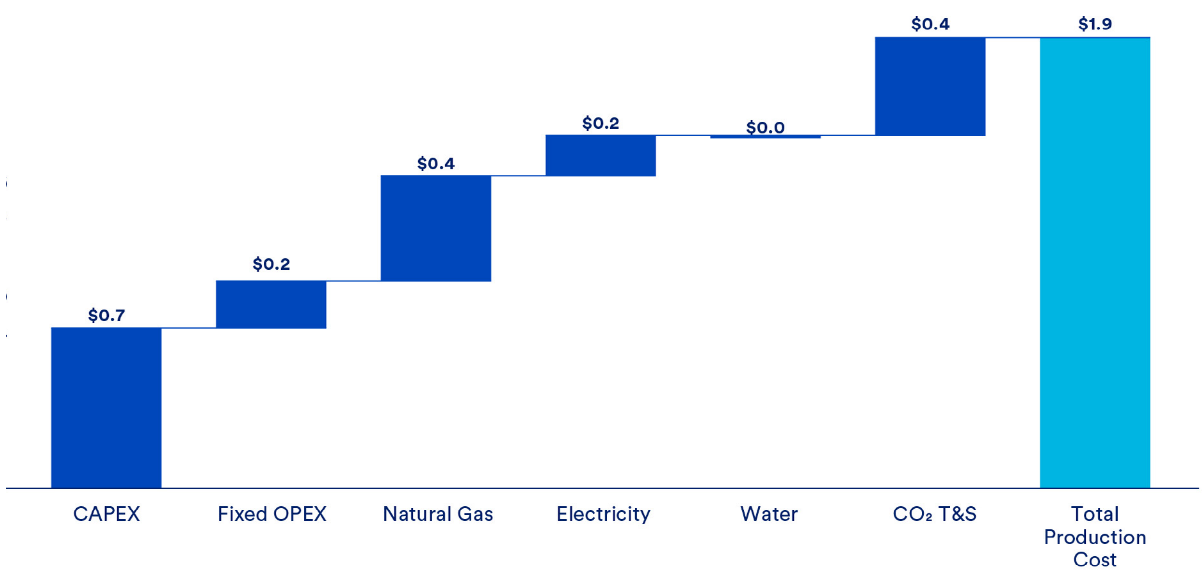
Hydrogen from Natural Gas with Carbon Capture

Figure 6 shows the cost drivers in USD per kg H_2 for hydrogen production from natural gas with carbon capture. Natural gas prices at Henry Hub typically hover around USD 3/MMBTU$_{HHV}$, which translates into a low-carbon hydrogen production cost of USD 1.9/kg (USD 12.6/MMBTU$_{HHV}$). There are also additional costs associated with potential hydrogen storage and transportation that will be conservatively estimated at USD 1/kg.[13]

The calculated cost of hydrogen made from natural gas with carbon capture assumes baseload operation of the hydrogen production plant for which it is typically designed for and best operated at. This contrasts with the operation of gas power plants that can easily load follow and cycle on and off. As such, the hydrogen production plant will need to be sized to operate at baseload capacity while also delivering sufficient hydrogen to supply one or more power plants and potentially other downstream users.

Autothermal reforming hydrogen plants can play a role in a predominantly renewables-powered grid as a fuel for dispatchable power plants, despite upstream emissions in the natural gas supply chain (these lifecycle emissions also become more manageable if hydrogen is only part of a portfolio of generation technologies in a decarbonized grid). A recent analysis from the National Renewable Energy Laboratory (NREL) provides us with insight into what capacity factor may be required from power plants powered by low-carbon hydrogen. The study shows the capacity factors of gas plants with and without carbon capture to range from 1 to 14% under different scenarios for the U.S. grid in 2050. We will therefore assume that gas plants using low-carbon hydrogen from natural gas and carbon capture will operate at 10% capacity factors, which also happens to be the historical average utilization rate for gas turbines used for peak-load duty cycles.

Figure 6: Cost build-up (2022 USD/kg H_2) for low-carbon hydrogen from natural gas with carbon capture in an autothermal reformer[14]



13 Any potential use of hydrogen that would require the storage of hundreds or thousands of tonnes of hydrogen must be done in Underground Seasonal Hydrogen Storage (USHS). The U.S. DOE Hydrogen liftoff reports puts levelized cost of hydrogen storage in salt caverns at USD 0.05 – USD 0.15/kg hydrogen. Furthermore, the liftoff report estimates hydrogen transport costs by pipeline at USD 0.2 – USD 0.5/kg hydrogen.

14 Real 2022 USD, Total Installed Cost estimated at USD 460 million for a 300MW ATR (79k tonne per year H2 capacity), 90% utilization, USD 50/tonne for the transport and storage of captured CO2, USD 50/MWh for electricity, 8% real pre-tax weighted average cost of capital (WACC), 25-year project lifetime. A 300-MW ATR is a medium-sized hydrogen production plant—this is also the size of the ATR used in the HyNet project. Operating parameters used in the levelized cost calculations are obtained from IEAGHG.

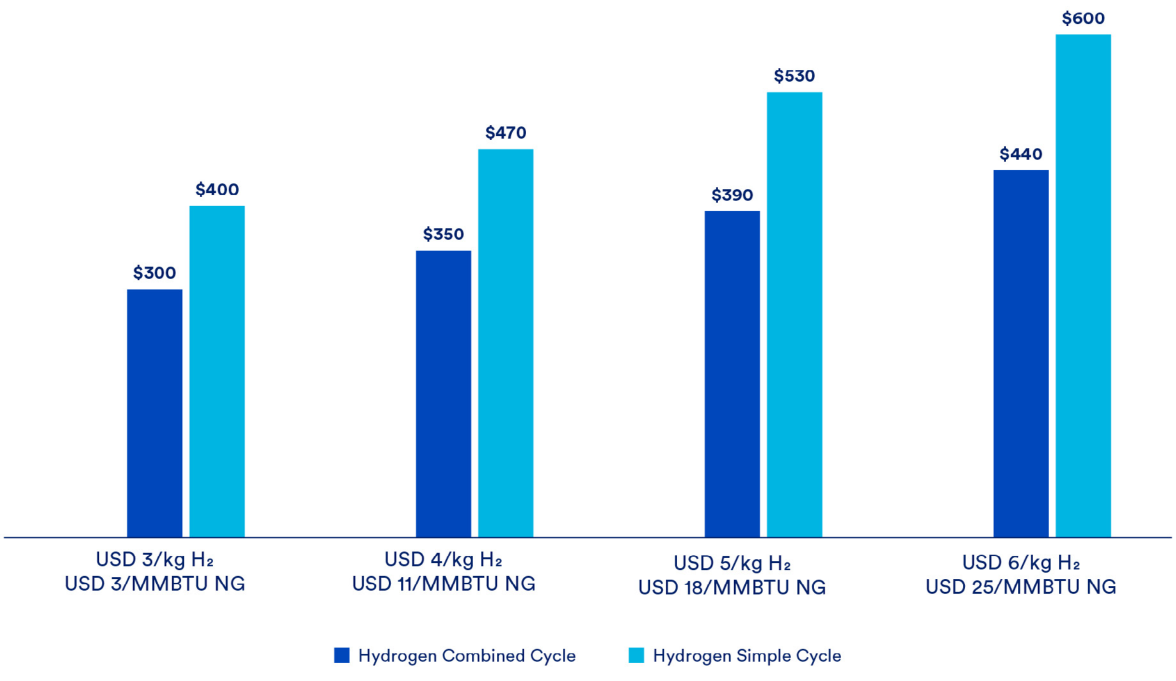
Levelized Cost of Electricity

Figure 7 presents the levelized cost of electricity (LCOE) in USD per MWh_e from a simple cycle and combined cycle power plant operating at a 10% capacity factor. In the case of clean hydrogen from an autothermal reforming hydrogen plant, the cost of hydrogen [and the LCOE from the subsequent electricity generation from this hydrogen fuel] corresponds to that produced using the natural gas price indicated on the x-axis.

As a reminder, the 10% capacity is chosen to represent the use of hydrogen in power plants for balancing excess surplus clean electricity and demand in a heavy renewable system. Note prior discussion in Section 3 that articulated how dedicated use of hydrogen for power is highly inefficient and land-intensive, and thus unlikely to occur at high-capacity factors when alternative clean firm technologies are available to operate at baseload conditions (see Figure 10).

Taking the estimated cost of USD 4/kg for electrolytic hydrogen, the estimated LCOE is USD 470/MWh_e for a simple cycle plant and USD 350/MWh_e for a combined cycle plant (both types of plants are assumed to operate at a 10% capacity factor). These estimates are in the same range as estimates developed by the Pacific Northwest National Laboratory (PNNL) for a 2022 report comparing the cost of various options for providing grid energy storage, including via hydrogen production. The PNNL report estimates the levelized cost of storage[15] for a hydrogen system at USD 370–400/MWh_e (in 2021 USD).

Figure 7: Estimated LCOE (2022 USD per MWh_e) from a simple and combined cycle power plant operating at 10% capacity factor using electrolytic hydrogen at several price points[16]



15 LCOS and LCOE are used interchangeable in this report since both refer to the average cost of a unit of electricity delivered using hydrogen as a form of grid-level energy storage. Thinking of a hydrogen production system as a kind of "battery", the LCOS for this battery comprises costs for electrolysis facilities, costs for hydrogen storage and transmission, and costs to generate electricity by operating a simple cycle power plant on hydrogen fuel.

16 Below the cost of hydrogen in the graph is the corresponding price of natural gas from which low-carbon hydrogen from an ATR with 94% carbon capture is produced.

It is worth noting that the price of natural gas has no impact on the LCOE for a power plant operating on electrolytic hydrogen. LCOE for a power plant operating on hydrogen made from natural gas with carbon capture, by contrast, will be affected by natural gas prices, since natural gas prices are a cost factor in hydrogen production. At a delivered natural gas price of USD 3/$MMBTU_{HHV}$, the delivered cost of hydrogen from an autothermal reforming plant is approximately USD 3/kg (~USD 22/$MMBTU_{HHV}$), and the estimated LCOE is USD 400/MWh_e for a simple cycle plant and USD 300/MWh_e for a combined cycle plant.

KEY TAKEAWAY 6

The levelized cost of storage via electrolytic hydrogen produced from surplus clean electricity is estimated to be in the range of USD 350 – USD 470 per MWh_e while the levelized cost of electricity from a power plant operating on low carbon hydrogen from an autothermal reforming hydrogen plant is estimated to be in the range of USD 300 – USD 400 per MWh_e.

Carbon Abatement Costs

Electrolytic Hydrogen

While these LCOE and LCOS figures can be informative when comparing to alternative storage pathways, carbon abatement costs may be more illustrative in understanding the economic cost for operating power plants on hydrogen as a climate mitigation measure. Carbon abatement costs are calculated by taking the difference in levelized cost for electricity generated using low-carbon hydrogen versus electricity generated using unabated natural gas (i.e. assuming unabated gas is being displaced) and dividing that difference by the anticipated reduction in lifecycle carbon emissions per unit of electricity produced.

In terms of cost to abate a tonne of CO_2 by using electrolytic hydrogen produced from surplus renewable electricity as a power plant fuel, this cost depends on two factors:[17] (1) the spread between the cost of electrolytic hydrogen produced from surplus clean electricity and the natural gas price and (2) the carbon intensity of the natural gas supply chain.[18]

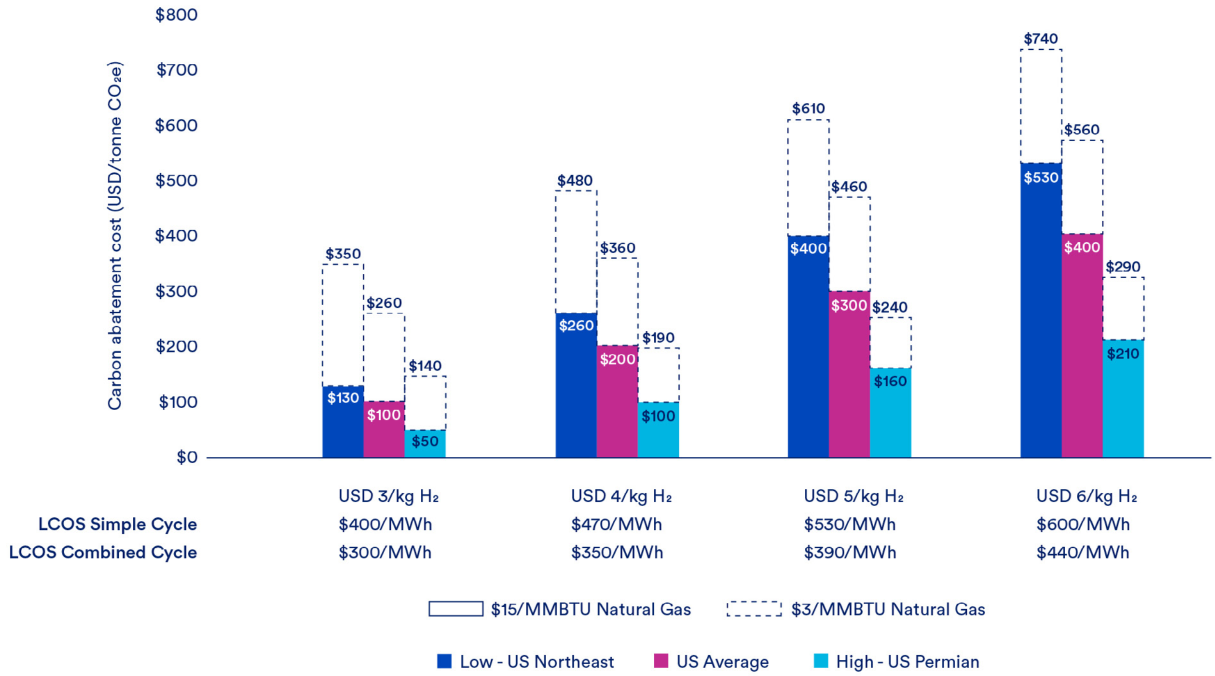
We begin by comparing emissions reductions from the use of electrolytic hydrogen against emissions from the use of unabated natural gas in simple and combined cycle power plants. As shown in Figure 8, the lower the levelized cost of storage using electrolytic hydrogen, the lower the cost of abating carbon by using electrolytic hydrogen as a power plant fuel. Since carbon abatement costs are calculated using CO_2 equivalents and account for upstream methane emissions, carbon abatement costs are lower if one assumes a higher carbon intensity for the natural gas supply chain. In that case, using hydrogen both avoids CO_2 emissions that would otherwise occur at the power plant and avoids a greater quantity of upstream emissions associated with delivering natural gas to the power plant. Finally, we considered lifecycle carbon abatement costs at two natural gas prices: USD 3/$MMBTU_{HHV}$ and USD 15/$MMBTU_{HHV}$. At the lower natural gas price, there is a greater cost penalty for operating the power plant on clean hydrogen instead of natural gas, which implies a higher carbon abatement cost. In the United States, the average Henry Hub wholesale price for natural gas has fluctuated around USD 3/$MMBTU_{HHV}$ historically and is currently forecast to remain at roughly this level. Arguably, efforts to decarbonize the grid will reduce demand for natural gas, putting downward pressure on future natural gas prices.

At a cost of USD 4 per kg of delivered electrolytic hydrogen and assuming U.S. average carbon intensity for the natural gas supply chain, the use of electrolytic hydrogen from surplus clean electricity as a power plant fuel delivers lifecycle carbon abatement at a cost of around USD 360 per tonne of avoided CO_2e.

17 Carbon abatement costs for power plants using the burn hydrogen are independent of the capacity factor of the power plant.

18 In the case of hydrogen produced from natural gas with carbon capture, the difference is simply the levelized cost of producing clean hydrogen from natural gas. This means that the cost of hydrogen production cannot be considered independently of the price of natural gas. In the case of electrolytic hydrogen, both the price of natural gas and the cost of producing electrolytic hydrogen can be varied independently for purposes of the analysis.

Figure 8: Estimated lifecycle carbon abatement costs (2022 USD/tonne CO_2e) of electrolytic hydrogen fueled power production at various production costs for hydrogen, various natural gas supply chain carbon intensities for the displaced gas, and various natural gas prices



Hydrogen from Natural Gas with Carbon Capture

Figure 9 shows carbon abatement costs in the range of USD 400 to USD 680 per tonne CO_2e for electricity generated by a combined cycle plant using hydrogen from natural gas with carbon capture. Carbon abatement costs reflect the costs incurred by switching to low-carbon hydrogen as a power plant fuel to avoid CO_2 emissions. Carbon abatement costs for simple cycle plants are 2% to 6% higher than those for combined cycle plants. The cost of hydrogen corresponds to that produced from natural gas at the price indicated on the x-axis.

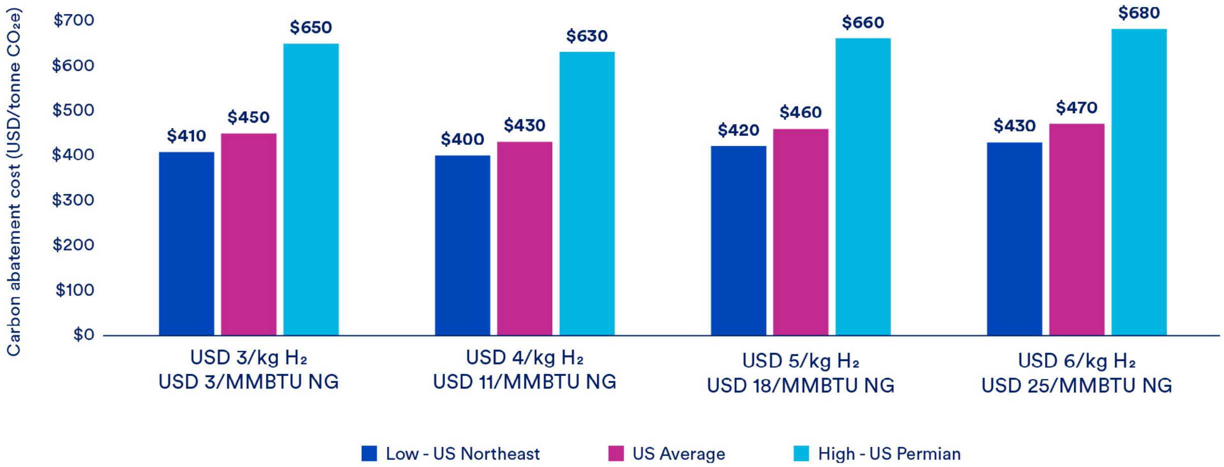
Compared to carbon abatement costs for electrolytic hydrogen, carbon abatement costs for hydrogen from an ATR plant increases with higher natural gas upstream methane emissions. This can be explained by further inspecting Figure 5 which shows smaller reductions in lifecycle emissions at higher natural gas supply chain upstream emissions.

At a cost of USD 3 per kg of delivered low-carbon hydrogen and assuming U.S. average carbon intensity for the natural gas supply chain, the use of low-carbon hydrogen from an ATR as a power plant fuel delivers lifecycle carbon abatement at a cost of around USD 450 per tonne of avoided CO_2e.

KEY TAKEAWAY 7

The lifecycle carbon abatement cost of electrolytic hydrogen produced from surplus clean electricity is estimated at USD 360 per tonne of CO_2e while that of hydrogen from natural gas and carbon capture is estimated at USD 450 per tonne of CO_2e.

Figure 9: Estimated lifecycle carbon abatement costs (2022 USD/tonne CO_2e) at various price points for hydrogen from natural gas with carbon capture and for various natural gas supply chain upstream emissions



Comparing Electrolytic Hydrogen to Alternative Energy Storage Systems and Clean Generation Technologies

Comparing hydrogen as an energy storage or generation option to other storage and generation technologies is tricky. As noted in the main text, electrolytic hydrogen generated using surplus clean electricity could function much like a massive chemical battery for a future decarbonized grid. However, whether such a "battery" is needed first requires a system-level analysis of whether it is more cost efficient to minimize the needs for long-duration storage with the use of clean dispatchable or baseload resources like geothermal, nuclear, or gas with carbon capture and storage.

Alternative clean generation dispatchable technologies can deliver electricity at very low marginal cost if they operate as high-capacity factor units, which reduces the need for long-duration storage and the land-use footprint of the clean electricity portfolio. As shown in Figure 10, the LCOE for a NGCC plant with 90% carbon capture operating at a 90% capacity factor is $70/ MWh_e.[19] Alternatively, the ability to ramp up firm nuclear or combined cycle natural gas plants can be viewed as providing a form of energy 'storage' (albeit not low carbon in the case of natural gas) at costs of USD 40/MWh_e and USD 130/MWh_e, respectively.

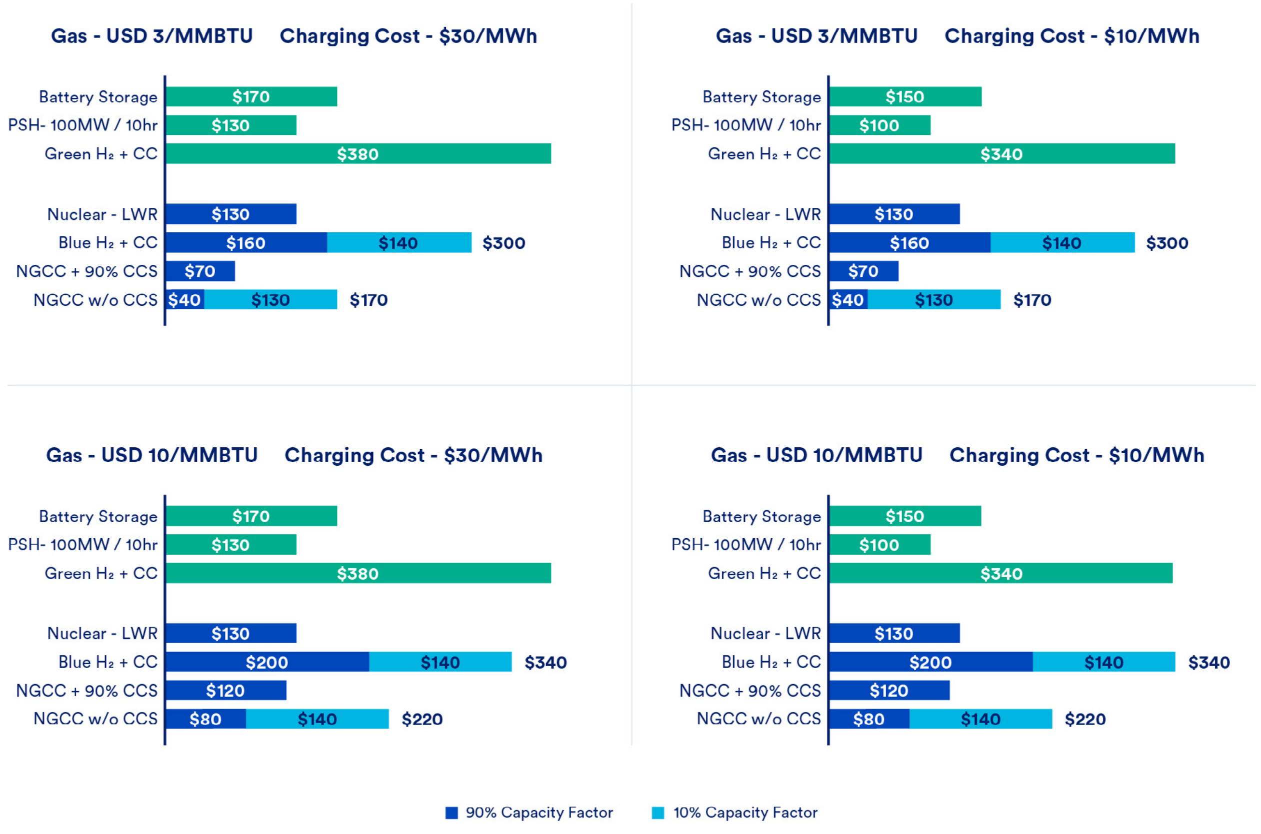
If longer duration storage is still deemed necessary, comparisons between storage technologies are still not simple. Unlike traditional batteries, a hydrogen energy storage system would not be limited by finite charging and discharging cycles or the depth of discharge and could hold its charge indefinitely, effectively being a long-duration storage technology. Furthermore, large quantities of hydrogen—sufficient to provide tens of gigawatt-hours of electricity—could be cost-effectively stored in geologic formations, which could supply hydrogen for many uses. Energy storage on this scale is not attainable with current battery technology, though geologic formations suitable for hydrogen storage are limited. However, traditional batteries, such as lithium-ion and vanadium redox flow batteries, outperform hydrogen as a storage option in terms of cost, round-trip efficiency, and response time. Thus, batteries can play a different role in grid balancing, most notably in responding quickly when short-term demand on the grid exceeds supply.

Therefore, hydrogen as an energy storage medium should be compared to other scalable and long duration storage technologies such as thermal storage and pumped storage hydropower (PSH). All these technologies, like hydrogen, can store quantities of energy on the scale of gigawatt-hours and dispatch power at a rate of hundreds of megawatts. For an energy storage system with 100-MW capacity and a discharge duration of 10 hours, the PNNL analysis concluded that PSH, with an estimated LCOS of USD 110/MWh_e outperforms hydrogen, which has a higher LCOS of USD 400/MWh_e.[20] PSH currently accounts for over 90% of global installed energy storage capacity, with the world's largest pumped hydro facility, in China's Hebei province, capable of delivering 3.6 gigawatts (GW) of electricity from 6.6 terawatt-hours (TWh) worth of storage. It is worth noting that all these long duration storage technologies are constrained by geography: PSH requires large reservoirs of water at different heights, while hydrogen systems must be in areas that offer geologically suitable underground formations for storing hydrogen.

19 Power system modeling geared to minimizing total system cost can result in outcomes such as low-capacity factor NGCC carbon capture power plants as a source of firm capacity. However, carbon capture plants are generally designed to operate at steady state conditions and do not load follow as is the case with standalone NGCC or simple cycle plants. Furthermore, given the capital intensity of carbon capture facilities and associated infrastructure including CO_2 pipelines, it is unlikely that the revenue generated from selling electricity at low-capacity factors will be sufficient to cover costs and recoup the investment.

20 PNNL uses different economic metrics (base currency year (2021), cost of capital (real pre-tax WACC of 6.52%) etc.) to evaluate LCOS than the metrics used in this paper. Furthermore, PNNL's analysis assumes that hydrogen is used in fuel cells rather than in simple or combined cycle power plants, which results in higher roundtrip efficiencies and yields lower LCOS estimates than our analysis. Nonetheless, what is important is the relative ranking of these technologies.

Figure 10: Estimated LCOE (2022 USD/MWhe) for various dispatchable and capacity resource technologies at various natural gas prices and electricity charging cost combinations[21]



21 Battery Storage, Nuclear and NGCC LCOE (Real USD 2022) calculations are based on data input from EIA AEO 2023 Cost & Performance data and a real pre-tax 8% WACC. Pumped storage hydropower LCOE is based on data input from the PNNL study. Battery LCOE based on a 50MW/200MWh storage, 90% depth of discharge (DOD), 90% RTE and one cycle per day. PSH based on a 100MW/1GWh storage, 80% depth of discharge (DOD), 80% RTE and 1.25 cycles per day.

Recommendations for Power Sector Decarbonization

- Evaluate the impact of power sector decarbonization pathways on total system costs and ultimately on the utility tariffs imposed on retail, commercial and industrial customers. Decarbonization investments should result in a power system that is sustainable, reliable, affordable, and beneficial to overall economic competitiveness.

- Follow an evidence-based approach to examine the needs for long-duration storage and the merits of using hydrogen as a medium for long-duration energy storage, if needed, in the context of a largely decarbonized grid. Detailed modeling of power systems is needed to understand the geographic and temporal landscape of system balancing needs, the availability of clean firm generation technologies (e.g geothermal, nuclear, gas with CCS) to reduce system balancing needs, the potential for excess supply during periods of high renewables availability, and to understand if hydrogen production can serve as an economic form of energy system storage.

- Fully account for associated physical and infrastructure requirements when evaluating electrolytic hydrogen production as an energy storage solution. While hydrogen offers a way to retain the energy content of surplus electricity in chemical form for long periods of time, a systems evaluation of the “hydrogen-as-battery” concept needs to be validated before deploying this approach at scale, especially to provide a service as critical as grid backup.

- Examine the technology and reliability risks of deploying hydrogen production as an energy storage solution, especially with regards to the performance of electrolysis facilities under quickly changing loads.

- Develop a business model for electrolytic hydrogen production from variable renewable sources to better understand the economics, capital investment requirements, and financing risks involved in launching such projects. Do not assume “free” surplus electricity, as the requirements for clean electricity development and hydrogen facility development will most likely require contracting a reliable supply of clean power. Moreover, do not assume plentiful excess clean electricity given the competing demands from electrified transport, industry, data centers, and more demand sources.

- Relying on dedicated clean hydrogen production, as opposed to that generated from surplus electricity, is in many cases a costly and inefficient decarbonization strategy for the power system. Prioritize dedicated clean hydrogen production for use as a feedstock in heavy industry (refining, fertilizer, iron production) and to decarbonize segments of heavy and long-haul transportation.

Conclusion

Using hydrogen as a fuel for decarbonizing power generation, while technically feasible, is unlikely to be economic at a large scale compared to other options for decarbonizing the power sector. Moreover, because the production and delivery of hydrogen requires large amounts of energy and incurs numerous supply chain inefficiencies, expanded reliance on hydrogen cannot be seen to improve energy security (on the contrary, increased generation hydrogen could significantly increase overall demand for other primary energy resources required to generate hydrogen, including clean electricity).

In contrast to its limited potential for decarbonizing the power system, low-carbon hydrogen is likely to have much more economic and climate value if it is used to decarbonize heavy industry, where hydrogen is already widely used but also overwhelmingly supplied, at present, using carbon-intensive production processes. Industrial application may also be able to avoid the need for costly storage and transport infrastructure that would be necessary for power sector applications. Hydrogen is also likely to be a useful and economic option for decarbonizing some heavy freight.

In the power sector context, electrolytic hydrogen production using surplus renewable electricity could have some role as a form of long-duration energy storage. In fact, pumped storage hydropower aside, electrolytic hydrogen production is arguably one of few technically feasible ways today to convert significant quantities of electricity to an energy form that can be stored over long periods of time (weeks and months) and then reconverted to electricity. However, a systems perspective can yield many alternative strategies for addressing (or reducing) the grid balancing challenges presented by large-scale deployment of weather-dependent renewable resources, such as increasing the amount of more cost-effective climate-friendly firm technologies such as nuclear and geothermal. The only economic case for hydrogen as a power plant fuel rests in regions where such alternatives are politically excluded, a policy decision which may significantly raise the costs of a low carbon grid.