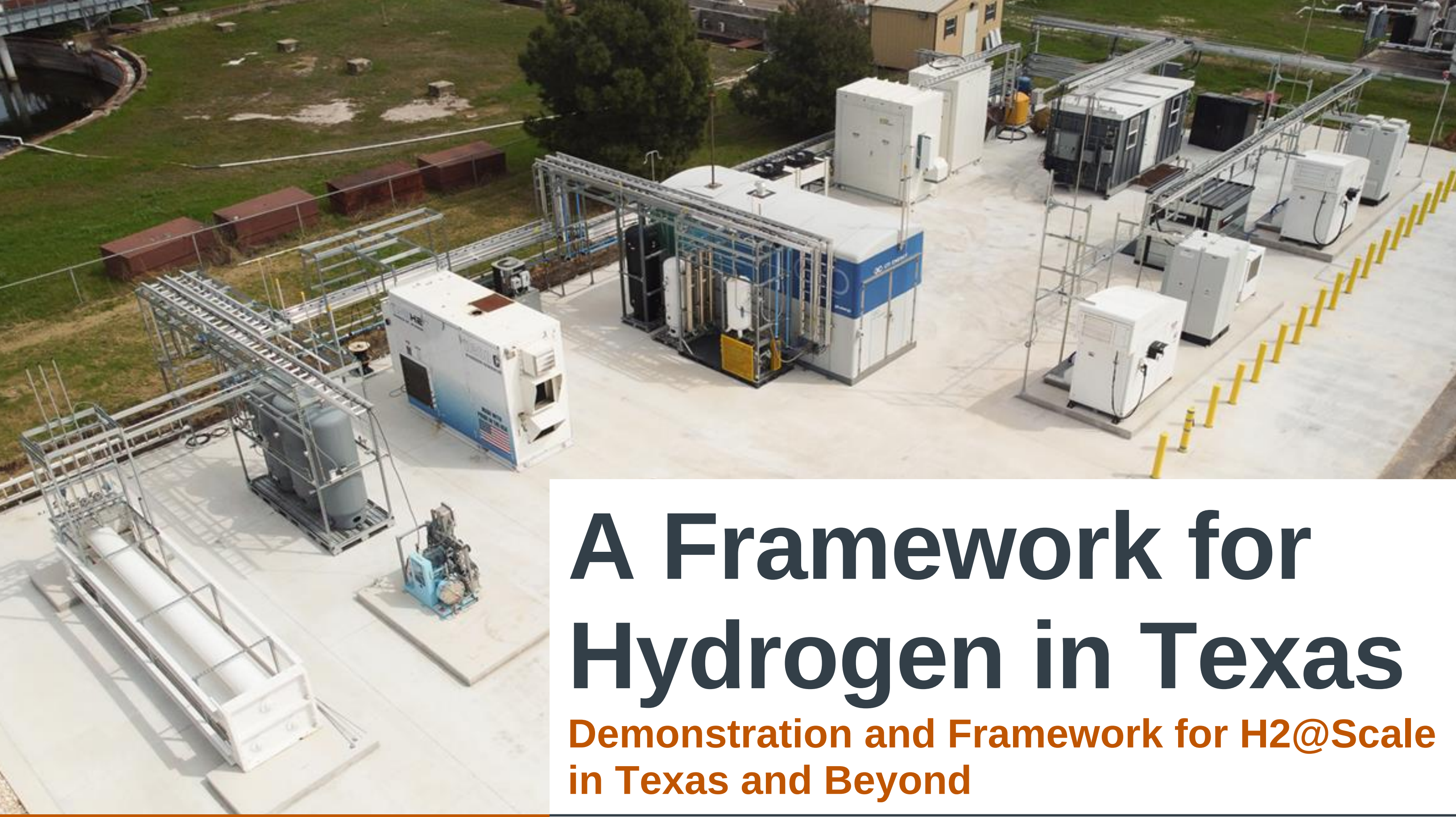

A Framework for Hydrogen in Texas

Demonstration and Framework for H2@Scale in Texas and Beyond

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Executive Summary: A Vision for Hydrogen in Texas

Building on its existing hydrogen infrastructure, experienced workforce, and natural resources, Texas is poised to be a global leader in the quest for an economical, at-scale hydrogen economy. A 2022 study estimated that a hydrogen-rich, net-zero Texas economy would have an economic benefit (business-as-usual) of more than $120 billion and create over 750,000 new jobs by 2050.[1]

Nonetheless, there are challenges to overcome before the benefits of a broader hydrogen economy can be realized. Among the largest of these challenges is cost. The 2023 levelized cost of hydrogen produced by reforming natural gas conventionally (i.e., with venting of produced CO_2) is about $1/kg using natural gas costing about $3.50/mmBtu (which is similar to the Henry Hub wholesale price for much of the last 15 years except for higher prices in 2021–22). Hydrogen produced by reformation processes with capture and sequestration of most of the produced CO_2 at those same natural gas prices may cost $1.50/kg to $2/kg. The cost of hydrogen produced from water—not natural gas—by an electrolyzer operating on low/zero-carbon electricity can be $4/kg to $6/kg, depending on the cost of power.[2] Hydrogen's effectiveness at reducing greenhouse gas emissions depends on the widespread use of low-carbon-intensity ("clean") hydrogen production processes, so addressing the current cost gap is critical. In addition to solving cost challenges for clean hydrogen production, technical and economic issues must also be addressed for build-out of at-scale hydrogen transportation and storage capacity, as well as in end-use device capabilities, particularly in applications that involve hydrogen combustion or electrochemical conversion.

Numerous Texas stakeholders, in both the public and private sectors, see a path to success. Although its policies to foster a hydrogen economy have not been as high profile as some of initiatives in other states or internationally, Texas established a vision and policy foundation for a hydrogen energy economy in the early 2000s. Although government policies can help remove barriers, sustained development success requires private investment. The Texas oil and natural gas industry, industrial gas companies, gas pipeline companies and utilities, process industries, power producers, and their equipment and service suppliers recognize the potential economic benefit from the growth of clean hydrogen infrastructure and understand the type and magnitude of sustained investments required to bring it to fruition.

Although sizeable infrastructure for the end-to-end hydrogen value chain is in place within Texas, numerous enhancements, modifications, and/or repurposing of existing infrastructure must occur, as well as substantial new infrastructure build-out, to accommodate a robust clean hydrogen market. To gain insight into how best to grow the Texas hydrogen infrastructure, the project team developed the Hydrogen Optimization with Deployment of Infrastructure (HOwDI) economic optimization model. The model comprises a spatially resolved optimization framework that determines location-specific hydrogen production and distribution infrastructure to cost-optimally meet a specified location-based demand. In particular, the project team used the HOwDI model to explore the influence of capital cost uncertainty for various hydrogen production and delivery technologies on the levelized cost of dispensed hydrogen at vehicle fueling stations. The potential reduction in dispensed fuel cost from incentives, such clean hydrogen production tax credits, was also examined.

The study found that many combinations of hydrogen production technologies and delivery modes can provide hydrogen at a fuel dispenser in many Texas locations at a cost of $4/kg-$H_2$, which is approximately equivalent to $4 per gallon of gasoline (which is a U.S. Department of Energy H2@Scale

[1] https://cockrell.utexas.edu/images/pdfs/UT_Texas_Net_Zero_by_2050_April2022_Full_Report.pdf
[2] https://www.iea.org/reports/the-future-of-hydrogen

goal[3]). This cost is deemed sufficiently affordable for heavy-duty trucks, in an emissions-constrained setting, to transition from diesel fuel to hydrogen fuel cell electric vehicles. In addition, new federal tax credits for clean hydrogen production appear likely to significantly reduce the delivered cost of clean hydrogen, averaged across the range of cost uncertainties, potentially accelerating adoption in transportation applications, as well as supporting decarbonization in various industrial and energy supply sectors.

The project team identified several potential next steps that Texas stakeholders could take to foster development of a clean hydrogen economy:

- Rollout heavy-duty fuel cell trucks and fueling stations.

Fueling stations serving medium- and heavy-duty trucks can potentially have lower levelized dispensed fuel costs because per-vehicle fuel use is high and many trucks require long ranges between fills and fast refueling times, which battery electric technology cannot satisfy. Focusing on the Texas Triangle freight corridors (bounded by Austin, Dallas-Fort Worth, Houston, and San Antonio) could generate the sufficiently large clean hydrogen demand to spur investment in hydrogen fueling stations (with locations along pipelines being the most economical) and associated clean hydrogen supply (i.e., production and delivery) capacity.

- Pursue hydrogen blending for power plant decarbonization.

There are more than 40 natural gas power plants in Texas located in close proximity to existing hydrogen pipelines—some owned by utilities, some owned directly by energy-using industries—that could reduce air emissions and create a large and potentially baseload demand for hydrogen through blending with natural gas. Low blending rates (<5% H_2 by volume) would entail few, if any, changes. Blending at higher rates could increase emissions reduction benefits and boost hydrogen demand, but such applications may also depend on facilities' operational flexibility and the materials of construction in fuel supply and combustion systems. Significant blending tests by natural gas utilities and research organizations are under way across the United States, Europe, and elsewhere that may provide insight. Assembly of best practices for hydrogen blending for the specific delivery and end use systems in Texas could inform scale-up feasibility assessments and implementation.

- Implement hydrogen production via natural gas reforming combined with carbon capture and sequestration.

The HOwDI model results showed that hydrogen production via steam methane reforming (SMR) combined with CO_2 capture and long-term storage was an economically preferred clean hydrogen production technology for many Texas demand centers. Other commercial, at-scale reforming processes with relatively similar cost and performance characteristics, such as partial oxidation (POX) and autothermal reforming (ATR), should be similarly economical. Numerous commercial projects are in various stages of development in Texas, with many along the Gulf Coast region near existing hydrogen

[3] Fiscal Year 2019 H2@Scale Funding Opportunity Announcement, DE-FOA-0002022, U.S. Department of Energy, Office of Energy Efficiency and Renewables Energy, 2019.

and CO_2 pipelines and existing hydrogen markets for ammonia, methanol, petrochemical, and refining operations. Other projects are being explored for the Permian Basin, where captured CO_2 could be used for enhanced oil recovery.

- Refresh policy incentives and bridge gaps.

For Texas to keep its leadership position and realize the growth potential in the end-to-end hydrogen value chain as global clean hydrogen demand grows, it is advisable to revisit and potentially update the state's policy framework and its role in federal and international initiatives (as Texas is poised to be a major export market supplier).

Given its current advantage in natural resources, existing infrastructure, and institutional knowledge, Texas is well poised to lead development of the future hydrogen economy. Building upon a foundation of effective industry-government-academic collaboration, Texas can leverage these advantages for major economic growth.

1. Scaling up the Hydrogen Economy in Texas

1.1. Hydrogen Overview

Hydrogen is one of the most abundant elements on Earth, but it is rarely found naturally in its most-usable diatomic elemental form (H_2), unlike methane and the other gaseous hydrocarbons making up natural gas, which can be used directly with little or no processing. Therefore, hydrogen must be "produced" (i.e., separated from hydrogen-bearing compounds) through electrical, chemical, thermal, or other means. Once hydrogen is produced, it can be used as a carbon-free fuel or as a feedstock in a wide variety of chemical processes. This versatility in combination with the ability to produce hydrogen in ways that reduce its life-cycle greenhouse gas (GHG) emissions makes hydrogen an attractive and a necessary energy commodity for mitigating climate change and improving air quality.

The most common commercial methods of producing hydrogen in Texas (and globally) involve the chemical reforming of methane (CH_4) with steam (H_2O) or oxygen (O_2) at elevated temperature and pressure, usually in the presence of a catalyst. In a conventional, two-reaction SMR process, hydrogen is liberated from both the natural gas hydrocarbons and the steam, with the remaining carbon and oxygen atoms combining to form carbon dioxide (CO_2), which historically has been vented to the atmosphere. Fired heaters to create the high temperatures necessary for the reforming reactions have also historically released CO_2 from combustion exhaust. A POX process uses oxygen as the reactant with the natural gas, rather than steam, and does not require a catalyst. Using the same second reaction as SMR, water-gas shift, increases the amount of product hydrogen and CO_2 by-product. ATR uses both steam and oxygen as reactants, essentially combining SMR and POX as well as creating a capturable CO_2 by-product. Accordingly, approaches to reducing greenhouse gas (GHG) emissions using hydrogen produced by conventional methods must examine how to minimize GHG emissions during production.

Examples include capture and sequestration of the CO_2 produced in the reforming reactions or substitution of the natural gas feedstock with renewable natural gas or biogas.

An alternative approach to hydrogen production that does not require a hydrocarbon reactant is the electrolysis of pure water by electric current. There are no CO_2 emissions at the point of hydrogen production—the electrolyzer—but its electricity use is substantial, so the life-cycle GHG intensity (also called carbon intensity) of the electricity used to power the electrolyzer govern the life-cycle carbon intensity of the product hydrogen. Electrolysis has not been used commercially at the scale of reformation processes for hydrogen production, but electrolysis projects at hundreds of MW scale are now under construction in Utah and in other countries.

Clean hydrogen production methods already at or near commercial scale include: (1) SMR with CO_2 capture and subsequent long-term storage (CCS), and (2) electrolysis powered by low or zero-carbon electricity. Other hydrogen production approaches, such as direct solar or nuclear thermal hydrogen production or methane pyrolysis, may provide longer-term alternatives, but near-term commercial deployment opportunities center on chemical reformation processes with CCS or electrolysis.

Replacing current carbon-intensive hydrogen with clean hydrogen in the myriad processes that use hydrogen as a feedstock would yield immediate benefits in reduced CO_2 emissions throughout the economy. In addition, hydrogen remains one of the only solutions for reducing emissions in many hard-to-abate sectors, such as steel manufacturing and heavy-duty trucking. Today, hydrogen is primarily consumed in the refining of crude oil into petroleum products and as an industrial feedstock to produce ammonia, methanol, and urea fertilizers. Emerging large-scale applications could see hydrogen as a fuel for direct use in combustion and electrochemical processes and as input into the production of clean liquid fuels, such as sustainable aviation fuel. Hydrogen can also be blended with natural gas as fuel for combustion applications, which allows for a longer transition to gas turbines, reciprocating engines, and other heat engines capable of firing 100% hydrogen.

1.2. Hydrogen Benefits

Achieving net-zero GHG emissions by 2050 will require dramatic changes to energy production, transmission, storage, distribution, delivery, and end-use systems. Hydrogen is an attractive decarbonization solution because it can serve as an energy carrier, a zero-carbon fuel, and an industrial feedstock to reduce the carbon intensity of numerous end-use products. In the electric power sector, hydrogen can be used to generate electricity (and heat) and it can also be used as a high-volume long-duration energy storage solution. Because hydrogen does not include any carbon atoms in its chemical composition, it does not produce CO_2 when combusted or when electrochemically reacted in a fuel cell. Although hydrogen combustion can produce oxides of nitrogen (NO_X), technologies exist to mitigate stack or tailpipe emissions.

Hydrogen has the potential to reduce emissions in a variety of sectors, including transportation, industry, power, and buildings. When considering decarbonization approaches, hydrogen is particularly well suited for sectors where other options (e.g., electrification) are not feasible. Examples include industrial applications requiring high temperature heat, steel production, and long-distance heavy-duty transportation and aircraft. Because hydrogen is already widely used in the oil and gas, chemicals, fertilizer, and food processing sectors, reliable means for its production, distribution, and storage are commercially available. Production needs to evolve to clean technologies, economically, but the downstream storage and delivery processes are essentially the same regardless of how the hydrogen was produced. Scaling clean hydrogen production and developing the technologies needed to utilize hydrogen in new applications requires a significant expansion of both the infrastructure to handle the hydrogen as well as the feedstock and technologies to produce it.

1.3. Hydrogen Challenges

Cost is chief among the barriers to expanded deployment of clean hydrogen and the development of a broader hydrogen economy. Other challenges include the technology readiness levels of hydrogen end-use technologies and the availability and scale of the current hydrogen infrastructure in comparison with existing infrastructure for natural gas and electricity.

The levelized cost of producing hydrogen using SMR or other reformation processes at large industrial scale, without additional measures to capture and sequester by-product CO_2, is about \$1/kg-H_2 when wholesale natural gas prices are at the level of the decade of 2011–2020 and currently in 2023, about \$3–\$3.50 per million Btu. (Wholesale natural gas prices were higher in 2021–22, and throughout most of the decade from 2001–2010, which increased the cost of conventional hydrogen production during those times.) The inclusion of measures to capture and sequester by-product CO_2, yielding clean hydrogen, increases the levelized cost of hydrogen production by about \$0.50–\$1.00/kg-H_2, for a total cost of \$1.50–\$2/kg-H_2. The specific incremental cost of adding CCS to SMR depends on the CO_2 capture rate and the availability and cost of CO_2 transportation and storage options.[4]

In contrast, the current levelized cost of hydrogen produced by a commercial aqueous alkaline or polymer electrolyte membrane (PEM) electrolyzer is on the order of \$4–\$6/kg-H_2, with the specific cost being a strong function of the cost of electricity used to drive the water decomposition reaction.[5] The cost of electricity is usually the largest contributor to the overall levelized cost of electrolytic hydrogen. The carbon intensity of electrolytic hydrogen is a function of the carbon intensity of the electricity used in the electrolyzer. When zero-carbon electricity is used exclusively, the resulting hydrogen is also considered zero-carbon.

Previous analysis of electrolytic hydrogen production using the Texas grid found that the levelized cost of electrolytic hydrogen production would be roughly flat at full-load capacity factors above 65% (and higher at lower full-load capacity factors), suggesting that electrolysis plant operators using grid power could minimize the carbon intensity of their product hydrogen by electing to shut down during the modest number of hours when the carbon intensity of grid power was highest, without adversely affecting their cost for producing hydrogen. Further details of this analysis and results are provided in additional reading materials. The high cost of clean hydrogen and the paucity of CO_2 off-takers that can assure long-term sequestration of captured CO_2 are limiting both the replacement of existing conventional “unabated”

[4] https://www.iea.org/reports/the-future-of-hydrogen
[5] https://www.energy.gov/eere/fuelcells/hydrogen-shot

hydrogen production processes and the expansion of clean hydrogen technology into new end-use markets.

There are additional economic challenges with quantifying potential market demand, costs, and delivery pathways for an emerging energy commodity like hydrogen. Lack of price transparency is an example. The hydrogen market has historically been focused on a few large applications, such as petrochemical and ammonia production plants, with few buyers and even fewer sellers. With no indexes, established spot markets, or futures markets to reference, hydrogen prices are difficult to trend. As a counter to this historical market hurdle, new market entrants are emerging, along with new business models and technologies intended to drive down the price of hydrogen, especially clean hydrogen. Because of all this activity, the general overall cost trend for hydrogen appears downward. It is anticipated that lower costs will spur increased demand and increased market liquidity and transparency.

Texas and the Gulf Coast region bring a uniquely robust mix of hydrogen suppliers and end-use applications. This core hydrogen business and the delivery/supply infrastructure that supports it can be leveraged to expand clean hydrogen markets as well as introduce new business models for hydrogen generation and use. This region is a likely location for the establishment of a market index, which can then be used to create financial products, hedge future price fluctuations, and generally reduce the risk of hydrogen as a clean fuel solution.

Further technology improvements and infrastructure build-out in transportation, storage, and delivery are needed to make clean hydrogen economically competitive in a variety of sectors. For example, hydrogen fueling stations for fuel cell vehicles, such as heavy-duty trucks, are more costly (when amortized over low initial sales volumes of hydrogen) and could benefit from technology improvements and build-out at larger scale (when demand increases). Novel uses of hydrogen, such as in steelmaking, are seen in first-of-a-kind and technology demonstration plants around the world, however, benefits from economics of scale in hydrogen supply await wide-scale commercial deployment of these sectors.[6] For Texas, prioritization of targeted clean hydrogen applications can facilitate “early wins” in emissions reduction and return on investment, helping spur broader development of a robust and effective hydrogen economy.

1.4. Going Big

The U.S. Department of Energy’s H2@Scale initiative advances affordable hydrogen production, transport, storage, and utilization to provide revenue opportunities and enable decarbonization in sectors across the economy.[7] By fostering partnerships among industry, academia, and national laboratories, the H2@Scale initiative aims to unlock the potential of hydrogen as an energy carrier that unites energy resources and serves as a critical feedstock in multiple industries. The Regional Clean Hydrogen Hubs program extends this approach on a much larger scale. This project aims to serve as a building block to inform the development of Hydrogen Hub initiatives.[8] For example, the HyVelocity Gulf Coast Hydrogen Hub, based in the Houston region, plans to reduce the cost of clean hydrogen through the economies of scale in large-scale production plants using both natural gas reforming with CCS and renewable-powered

[6] https://www.ssab.com/en/company/sustainability/sustainable-operations/hybrit-phases
[7] https://www.energy.gov/eere/fuelcells/h2scale
[8] https://www.energy.gov/oced/regional-clean-hydrogen-hubs

electrolysis. To lower the cost of hydrogen distribution and storage, the Gulf Coast Hydrogen Hub is planning a pipeline network with large-scale salt cavern storage. Planned hydrogen end uses include fuel cell electric trucks, industrial process feedstocks, ammonia synthesis, oil and petroleum products refining, petrochemical production processes, and marine fuel (e-methanol). Adoption of clean hydrogen in these applications should reduce CO_2 emissions by about 7 million metric tons ("tonnes") per year.[9]

1.5. Hydrogen in Texas

With an abundance and diversity of natural energy resources, geographical location, and existing energy (and hydrogen) infrastructure, expertise, workforce, and industry facilitating approach, Texas is an ideal location for clean hydrogen deployment, and it stands to benefit significantly from a growing and expanding hydrogen economy. A 2022 study on getting Texas to net zero found that a hydrogen-rich, net-zero Texas economy would come with an additional 766,000 jobs and an average net economic benefit of $122 billion compared with business-as-usual scenarios by 2050.[10]

For both natural gas (SMR with CCS) and zero-carbon electricity-based (electrolysis) hydrogen production pathways, Texas offers ample resources. The state has the first and fourth largest wind and solar fleets, respectively, and is first in natural gas production in the United States.[11,12] Texas also offers opportunities to sell CO_2 captured during hydrogen production for enhanced oil recovery (EOR) and other applications that conclude in long-term sequestration.

Texas' geology is well suited for supporting a hydrogen economy. The state has the potential for geological storage of hydrogen in depleted oilfields, salt caverns, and saline formations onshore. There is also potential for geologic storage onshore and in the near-offshore for CO_2 generated by thermal hydrogen production processes. Three commercial large-scale geological storage facilities for hydrogen are operating in Texas. Each of these utilize salt caverns for storing and recovering hydrogen for industrial use. The combined capacity is over 14,000 tonnes of hydrogen. For example, Linde's pipeline and salt cavern alone store 5900 tonnes of high-purity hydrogen.[13]

The quantity of storage volume is significant. The salt caverns that store hydrogen commercially in Texas today have a storage capacity in excess of 40 GWh. These have been operated commercially for years and therefore validate technology maturity. A planned facility near Corpus Christi, Texas, has initial project expectations for 2 GW of hydrogen production and two storage caverns to be operational by 2026.[14] Given that Texas' peak electricity demand is about 80 GW and that the total installed utility-scale battery capacity is on the order of 3 GWh, hydrogen energy storage could play a key role in fully utilizing renewable energy resources.[15,16]

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[9] https://www.energy.gov/oced/regional-clean-hydrogen-hubs-selections-award-negotiations
[10] https://cockrell.utexas.edu/images/pdfs/UT_Texas_Net_Zero_by_2050_April2022_Full_Report.pdf
[11] https://www.eia.gov/state/analysis.php?sid=TX
[12] https://www.eia.gov/beta/states/states/tx/rankings
[13] UT BEG/CEM RFI Response, 2022.
[14] https://www.dieselgasturbine.com/news/World-s-largest-green-hydrogen-hub-announced-in-South-Texas/8018797.article
[15] https://www.statesman.com/story/business/2022/07/06/texas-power-grid-electricity-demand-hits-record-high/65368086007/
[16] https://www.energy-storage.news/texas-largest-battery-project-to-date-brought-online-by-vistra

Texas also has substantial existing hydrogen infrastructure. Texas produces 3.6 million tonnes of hydrogen each year, about one-third of the total consumption in the United States.[17] Texas has over 900 miles (1450 km) of hydrogen pipelines within the state and is interconnected other pipelines along the Gulf Coast region as part of a network of nearly 1600 miles (2600 km).[18] Texas is an attractive location for developing the foundation for a future national hydrogen economy and energy system, in part, because of the ability to leverage its existing hydrogen system. This system includes infrastructure, supply chains, and a trained workforce. Texas also has growing economic sectors with increasing hydrogen demand as well as substantial resources for producing clean hydrogen economically.

2. From Production to Consumption

2.1. Hydrogen Production

Commercial processes for producing hydrogen from natural gas include SMR, POX, and ATR. ATR is essentially a combination of SMR and POX. SMR has the largest installed capacity in the United States overall and in Texas. Methane pyrolysis is a developmental technology. Hydrogen production by gasification of coal and/or petroleum coke, followed by water-gas shift, is used commercially in areas where the capital cost of process plant construction is low and natural gas is expensive relative to solid fuels, most notably China. Hydrogen production by electrolysis of deionized water uses no natural gas or other hydrocarbon feedstock. Some electrolysis technologies are commercial, whereas others are developmental. All are currently at scales smaller than reformation processes.

If the CO_2 produced during the reformation/gasification and water-gas shift reactions is separated and sequestered, the product hydrogen is low in life-cycle carbon intensity (i.e., “clean”). Hydrogen production by electrolysis releases no CO_2 during production, and thus the carbon intensity of electrolytic hydrogen is a function of the electrolyzer’s efficiency and the carbon intensity of its electricity feed. If the electricity is from renewables, nuclear power, or fossil power plants with CCS, the resulting hydrogen potentially has the lowest carbon intensity of any hydrogen production method. Methane pyrolysis also inherently produces clean hydrogen. Given Texas’ access to fossil fuel resources, renewable electricity, and geologic formations suitable for CO_2 sequestration (directly or post-EOR), it is likely that clean hydrogen production facilities in the state, ether new-build or retrofit, will employ a variety of hydrogen production processes.

2.1.1. Steam Methane Reforming

In the SMR process, hydrogen is produced using high-temperature heat, pressure, and catalysts to convert methane and steam in two reaction steps (i.e., synthesis gas or “syngas” production and water-gas shift) to H_2 and CO_2. Reformers can be fed with a host of carbonaceous feedstock materials, including fossil fuels (natural gas, coal, petroleum coke, liquid petroleum gases, oil, naphtha), biomass (corn stover, wheat straw, forest residue, or energy crops), or municipal waste, but they must be desulfurized before reaction. The purity, cost, and carbon intensity of the hydrogen product are sensitive

[17] https://www.mckinsey.com/capabilities/sustainability/our-insights/houston-as-the-epicenter-of-a-global-clean-hydrogen-hub
[18] https://www.utilitydive.com/news/texas-hydrogen-proto-hub-leads-the-us-in-technical-potential-for-doe-fund/622565/

to the feedstock. In commercial practice, natural gas is by far the most widely used SMR feedstock in the United States, including Texas.

SMR technologies are relatively efficient and generally have low operating costs compared with other hydrogen production technologies. To reduce the carbon intensity of hydrogen produced, SMR can be coupled with CCS technology. Depending on how CO_2 capture is applied within the SMR process (i.e., to just the reactants product stream or to both the product stream and the exhaust of fired heaters), the amount of CO_2 captured is typically either about 50–60% or about 90%.

2.1.2. Partial Oxidation

POX is non-catalytic process that partially combusts a hydrocarbon in a pressurized reaction vessel with a predetermined (substoichiometric) mixture of pure oxygen. The resulting reaction is similar to that of SMR, but instead of an endothermic reforming reaction driven by high-temperature steam feed and fired heaters external to the reaction tubes, the POX reaction is exothermic. By replacing steam as a feedstock with high-purity oxygen, the reforming reaction results in a higher percentage of carbon monoxide in the product syngas, which is converted in a downstream catalytic water-gas shift reactor to hydrogen and CO_2. Historically, the CO_2 was vented to the atmosphere, but it can be sequestered to yield clean hydrogen. The high-purity oxygen required by the POX process is typically produced by a cryogenic air separation unit, which represents a significant parasitic load. POX with a natural gas feedstock is in essence a process of "gasifying natural gas." The announced large-scale Air Products hydrogen/ammonia project in Ascension Parish, Louisiana, will use POX technology with a CO_2 capture rate of about 95%.[19]

2.1.3. Autothermal Reforming

ATR combines the SMR and POX reactions into a single process unit, with the exothermic substoichiometric oxidation reaction providing the heat for the endothermic reforming process. ATR is claimed to have higher production capacity than POX and faster start-up and response times than SMR. As with POX, ATR requires pure oxygen, which is typically provided by a cryogenic air separation unit (at significant capital expense and parasitic energy load). Accordingly, ATR hydrogen production plants generally need to be very large for optimal cost-effectiveness. Although the ATR reactions can draw oxygen from an air feed instead of a high-purity oxygen feed, thereby avoiding the cost of the air separation unit, the volume of nitrogen in air accompanying the flow rate of oxygen needed for the reactions would require much larger equipment to accommodate very large gas volumes and thus would increase system capital costs. A 2022 DOE National Energy Technology Laboratory comparison of commercial state-of-the-art hydrogen production technologies, using fossil fuel feedstocks, selected a CO_2 capture rate of 94.5% for its techno-economic case of ATR with a natural gas feedstock.[20] The European H21 project found that for an optimized ATR process, the CO_2 capture rate would be about 94%.[21]

[19] https://www.airproducts.com/campaigns/la-blue-hydrogen-project
[20] https://www.netl.doe.gov/projects/files/ComparisonofCommercialStateofArtFossilBasedHydrogenProductionTechnologies_041222.pdf
[21] https://www.h-vision.nl/application/files/1216/0733/4674/H-vision_Bijlagen_bij_het_eindrapport.pdf

2.1.4. Gasification

Gasification is essentially a POX process using solid or heavy liquid fuel carbonaceous feedstocks. At very high temperatures and elevated pressure, hydrocarbons and/or organics are converted to a syngas in a substoichiometric environment (i.e., limited oxygen and steam), without a catalyst. The syngas consists primarily of CO and hydrogen, along with lesser amounts of methane, CO_2, and other compounds. After syngas cooling, particulate removal, and sometimes sulfur removal, a catalytic water-gas shift reaction converts much of the syngas CO to CO_2 and H_2, boosting overall hydrogen production (akin to the use of water-gas shift in other reforming processes). Where sulfur removal does not precede the water-gas shift reaction, it must be removed from the product hydrogen afterward. Further, additional hydrogen purification and dehydration may be needed as well, depending on the specifications of the end-use application.

Gasification can accommodate a wide range of feedstock types, including those with low costs on an energy-content basis, such as coal, coal wastes, and petroleum coke, as well as renewable biomass and some solid wastes. Although CO_2 separation from other by-product acid gases for sequestration has not been standard practice, it has been proven commercially for capture rates up to about 90%. The carbon intensity of hydrogen produced by gasification is highly dependent on the feedstock and degree of CCS used. As with ATR, gasifiers can draw oxygen from an air feed in lieu of high-purity oxygen, but "downstream" equipment sizes would need to be larger and more costly and CO_2 separation is less efficient.

2.1.5. Methane Pyrolysis

Methane pyrolysis involves an endothermic equilibrium reaction, typically aided by a catalyst, conducted in the absence of oxygen or water. Because no oxygen atoms are present, no oxides of carbon (CO or CO_2) are formed. The carbon atoms in the methane are converted to a solid carbon slag, often referred to as black carbon. This process inherently produces clean hydrogen. However, if air or water is present in the feedstock due to incomplete dehydration of the methane feed, gaseous oxides of carbon will form, reducing the purity of product hydrogen. Most methane pyrolysis processes are currently at the laboratory/pilot or pre-commercial demonstration stages of development.

2.1.6. Electrolysis

Electrolysis encompasses a range of technologies that convert electrical energy to chemical energy in the form of hydrogen. Electrolysis uses an electrical current to decompose water into its constituent molecules—hydrogen and oxygen. Electrolyzers are essentially fuel cells operating in reverse, and thus electrolyzers are characterized by their electrolyte chemistry and structure in a manner similar to fuel cells. The most commercially established electrolysis technology uses an aqueous alkaline electrolyte, generally potassium hydroxide, operating at a temperature slightly elevated from ambient. PEM electrolyzers, which are also commercial, similarly operate at a temperature just above ambient. A platinum group metal catalyst facilitates the ionic reaction. Both technologies can accommodate varying rates of electricity supply, with PEM being the most flexible, and thus both technologies pair well with variable renewable electricity. Solid oxide electrolyzers are less commercially mature, but with their higher operating temperature, they avoid the use of expensive platinum group metal catalysts and offer the potential to achieve very high efficiencies for baseload hydrogen generation. The primary component of the levelized cost of electrolytic hydrogen is the cost of electricity supplied to the electrolyzer. The source of electricity also determines the carbon intensity of the product hydrogen. Leveraging the renewable power industry in Texas, and new federal tax credits, could enable cost-competitive, zero-carbon hydrogen production.

2.2. Hydrogen Demand

Clean hydrogen can play a vital role in reducing GHG and pollutant emissions across the economy, from industrial uses to transportation. At a high level, end-use applications for clean hydrogen can be grouped into the following categories: industrial feedstock, industrial heat source, power generation fuel, and transportation fuel. In all cases, this demand can be local, regional/state-level, national, or global, with the latter presenting an opportunity for the export of clean hydrogen from Texas to lucrative overseas markets.

2.2.1. Industrial Feedstock

Much of the hydrogen currently used in Texas serves as a feedstock to oil refineries and ammonia production plants. In refineries, hydrogen is used to remove sulfur from fuels and to crack long hydrocarbon chain molecules and form “lighter hydrocarbon” products. The ammonia (NH_3) synthesis process combines hydrogen with nitrogen drawn from air. The leading use of ammonia is as an agricultural fertilizer, either directly, or through further processing to urea compounds. Ammonia also has numerous industrial uses. The oil refining and ammonia production industries are well established and currently consume nearly all of the hydrogen produced in Texas. As such, these markets present a vast, near-term opportunity for the adoption of clean hydrogen as a feedstock in existing industrial plants to reduce the carbon intensity of their products. Absent regulations or other drivers that alter demand, the challenge to expanding clean hydrogen usage in established industries is to reduce production costs to levels competitive with conventional, higher-carbon-intensity hydrogen.

2.2.2. Industrial Heat

Industrial heat is a broad-based energy-consuming sector with the potential to become a near-term, growing market for clean hydrogen. Many industrial processes require externally supplied heat to drive chemical processes, manufacturing, and other facets of their operations. Examples include steelmaking, of which Texas is among the top five states in the country,[22] and cement manufacturing, for which Texas is the leading state for production and consumption.[23] For industrial applications requiring high temperature heat, currently supplied by fossil fuels, it may be impractical to substitute concentrated solar energy or electric resistance heating. For these applications, combustion of clean hydrogen could be a feasible alternative that would meet process requirements while also reducing net CO_2 emissions. As with the use of hydrogen as a chemical feedstock, incentivizing and producing clean hydrogen that is cost-competitive with traditional fuel sources for heat remains a challenge. Depending on the burner

[22] https://www.fedsteel.com/insights/five-states-strongest-steel-industries/
[23] https://www.cementx.org/files/CCT%20Info%20Sheet%201.pdf

design, hydrogen combustion can also produce significant oxides of nitrogen emissions that may require post-combustion catalytic reduction.

2.2.3. Power Generation

Power plants fueled by hydrogen, blended initially with natural gas, represent a large potential market for clean hydrogen while also helping bolster resiliency in the Texas power grid. Further, hydrogen is viewed as a key contributing solution to the need for vast quantities of grid-scale energy storage to balance increasing variable renewable electricity. Otherwise, curtailed wind power, for example, could energize electrolyzers to produce hydrogen.

Major gas turbine manufacturers (e.g., Mitsubishi Power, GE, Siemens) are developing or currently offer models capable of firing blends of natural gas and hydrogen, typically up to about 30% H_2 by volume in machines equipped with "dry, pre-mix" combustors and at higher hydrogen rates (50–100%) in machines with "diffusion" combustors (although the latter typically require demineralized water injection for NO_X control). Similarly, manufacturers of medium-speed reciprocating engines for utility-scale power generation (e.g., Wärtsilä, MAN Energy Solutions) offer spark-ignition engines capable of firing blends of hydrogen with natural gas, generally up to 25% hydrogen by volume.

An initial analysis assessed the potential for co-firing hydrogen in Texas natural gas plants in order to reduce electric sector CO_2 emissions. The study found that if all natural gas power plants within 3 miles (5 km) of existing hydrogen pipelines in Texas (43 in total) blended 5% of their fuel (by volume) with hydrogen, CO_2 emissions for those plants could drop by about 2.2% or 1.8 million tonnes per year. Results of this analysis can be found in additional reading materials.

2.2.4. Transportation

Hydrogen fuel cell electric vehicles (FCEV) use electric drivetrains powered by on-board PEM fuel cells fed with high-purity hydrogen. For technical reasons, these vehicles also tend to include a small lithium-ion battery. FCEVs produce no tailpipe CO_2 or pollutant emissions. Depending on the specific application, they also offer an efficiency improvement compared with gasoline or diesel internal combustion engines. FCEV usually have a longer range than battery (only) electric vehicles. Although refueling must take place at dedicated stations, FCEV refueling times are much faster than charging times for battery electric vehicles, even when they use DC fast chargers. Because hydrogen is a very energy dense form of energy on a mass basis, onboard hydrogen storage has much less of an impact on a truck's payload carrying capacity relative to batteries, which are heavy (i.e., have a low mass-basis energy density). Given the diversity of vehicle types and applications across the transportation sector, FCEV technology may be especially competitive for uses that require high energy density and fast refueling times, such as heavy-duty trucking, trains, port equipment, marine vessels, etc. Niche applications include FCEV forklifts in multiple-shift operations where there is no opportunity to recharge a battery electric counterpart. Multiple businesses, including H-E-B, Sysco Foods, and Walmart, have employed fuel cell forklifts in Texas for several years. The challenge, once again, resides in reducing the cost of clean hydrogen versus the incumbent fuel, as well as the total cost of ownership for the hydrogen-powered vehicle compared with its fossil fuel or battery electric counterpart. In addition, retail hydrogen fueling stations are not available in Texas today; behind-the-fence dedicated stations may require a large FCEV fleet to involve smaller-scale packaged fuelers with longer refueling times.

Researchers and engine manufacturers have also explored hydrogen fueled internal combustion engines (H2ICE) for vehicles. For example, in the mid to late 2000s, automakers such as BMW and Ford worked with research organizations such as Argonne National Laboratory on light-duty vehicle H2ICE, in part to address California Air Resources Board requirements to introduce hydrogen-fueled zero emission vehicles. Much of the fundamental combustion R&D, component materials testing, track/road testing, and emissions testing from this era provide a knowledge base relevant to current and future H2ICE development efforts. In 2022, Cummins displayed a 15-liter displacement H2ICE at an industry trade show. It also announced its intent to introduce a 6.7-liter displacement H2ICE. As with FCEV, H2ICE vehicles produce no tailpipe CO_2, but they can emit NO_X, at levels dependent on combustion conditions (e.g., stoichiometry). H2ICEs are viewed as a "this decade" option for transitioning to zero carbon hydrogen technology in several transportation applications. H2ICEs can accommodate lower-purity hydrogen than PEM fuel cells and are more tolerant of dusty environments and thus appear to be suited to application in agricultural and construction equipment. H2ICEs may also be more readily to retrofit to existing vehicle platforms using diesel engines. Development challenges remain in controlling NO_X emissions and reducing the propensity for engine knock (i.e., pre-ignition). Where H2ICE replace diesel engines, local particulate matter and air toxic emissions can be reduced significantly, which supports initiatives to improve air quality in communities historically burdened with air pollution. The potential cost of achieving this benefit raises a policy question: should large-scale hydrogen deployment wait until the cost of hydrogen and fuel cells come down in order to maximize the benefit of its application (albeit deferred), or should the build-out hydrogen infrastructure begin earlier to provide benefits that may be ultimately smaller, but are realized in a nearer term?

2.2.5. Exports

Many countries are setting ambitious decarbonization targets using strategies that will increase the demand for clean hydrogen. In particular, the European Union has an announced an updated energy strategy that would require the import of significant amounts of clean hydrogen or commodity chemicals made from clean hydrogen such as ammonia or methanol.[24] With in-state resources to produce cost-competitive clean hydrogen coupled with existing port infrastructure along the Gulf Coast, Texas has the potential to build hydrogen export capability to meet international hydrogen market demand.

2.3. Hydrogen Distribution Infrastructure

A more robust and expanded hydrogen economy will require new infrastructure for hydrogen transmission and delivery. This includes hydrogen pipelines and storage, as well as fueling stations for FCEVs. As new clean hydrogen infrastructure is deployed, environmental impacts will need to be addressed, including the potential for hydrogen leakage. Hydrogen has indirect warming effects, so minimizing and monitoring leakage will be an important part of a hydrogen distribution system.[25]

[24] https://ec.europa.eu/commission/presscorner/detail/en/IP_22_3131
[25] Ocko and Hamburg. Climate consequences of hydrogen emissions. Atmospheric Chemistry and Physics. June 2022. https://acp.copernicus.org/articles/22/9349/2022/acp-22-9349-2022.pdf

Research at California State University, Los Angeles,[26] indicated a hydrogen loss rate from on-site production to fueling station dispenser ranging from 2% to 35%. Some of these impacts and costs can be minimized by designing a hydrogen system that includes monitoring and co-location of production with demand where feasible.

2.3.1. Hydrogen Transport and Delivery

Hydrogen is transported commercially in three ways: in pipelines as compressed gas, by truck or railcar as a cryogenic liquid, and by truck as a compressed gas in cylinders (“tube trailers”). There is no distinction between the methods used to transport and deliver clean hydrogen and conventional hydrogen; thus, there is no technology barrier to expanding clean hydrogen transportation and delivery infrastructure.

Pipelines offer the highest capacity and are generally the most economical way to transport large and continuous quantities of hydrogen between regional supply and demand centers. Hydrogen pipelines in Texas and elsewhere in the United States are most often owned and operated by industrial gas companies, which typically serve as “merchant” providers of a bundled service including the hydrogen commodity, storage as needed, and delivery to the end user (in contrast to a regulated, common carrier service for transportation only). Continued investment and build-out of hydrogen transportation and delivery infrastructure by industrial gas companies will be an important element of regional infrastructure expansion plans and the ability to supply clean hydrogen to new large-scale end-use projects. However, because these private hydrogen pipelines are not normally under jurisdiction of the Federal Energy Regulatory Commission, operational history, customer connections, and volumetric and capacity information are not available consistently, which could pose a challenge for planners. Additional entities investing in hydrogen transportation and delivery infrastructure may include companies currently transporting natural gas under the open access model, including natural gas pipeline companies and natural gas utilities. Existing natural gas pipeline segments could potentially be used for delivery of blended fuel (with hydrogen content up to about 20% by volume, if permitted by regulators and standards organizations/insurers) with later conversion to higher hydrogen contents as demand grew and technical concerns were addressed. Alternatively, new, dedicated hydrogen pipelines could be built within existing natural gas pipeline corridors.

Texas leads the United States in existing hydrogen pipeline infrastructure with over 900 miles (1450 km), with some pipelines also connecting to Louisiana, the state with the second largest hydrogen pipeline infrastructure. The existing hydrogen pipeline network should be considered a “core asset” for the broader Gulf Coast region when evaluating new hydrogen markets, infrastructure expansion, and connectivity to clean hydrogen sources. Leveraging this network allows for new “at scale” projects to proceed quickly, as pipeline delivery capability is generally considered a prerequisite to market entry for clean hydrogen users requiring large quantities to make adoption viable, such ammonia and methanol synthesis plants, other industrial process plants, and electric utility gas turbine and reciprocating engine power plants.

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[26] Genovese M., Blekhman D., Dray M., Fragiacomo P. Hydrogen losses in fueling station operation. Journal of Cleaner Production. 2020 Mar 1; 248:119266.

Truck delivery of hydrogen will likely be an important market-entry approach for enabling hydrogen FCEVs within the Texas Triangle corridors. There are two options for hydrogen deliveries by truck. Liquid cryogenic hydrogen is delivered in special vehicles designed to store and transport hydrogen at temperatures at about -423°F (253°C). Gaseous hydrogen tube trailers, on the other hand, are designed to carry compressed hydrogen at pressures of about 3625 psi (250 bar), although some trailers have received U.S. Department of Transportation exemptions that allow transport at pressures of 7250 (500 bar) or higher.[27] For large applications that would be considered “at scale,” hydrogen deliveries by truck may tend to be in liquid form because of the lower transportation cost per kg, especially when delivered over distances greater than 150 miles (240 km).

Alternative delivery methods include shipment of hydrogen energy in the form of ammonia, methanol, or liquid organic hydrogen carriers such as methylcyclohexane. These methods allow for transport of large quantities of hydrogen over great distances at ambient temperatures and pressures. Additional costs are incurred by having to produce the hydrogen carriers at the point of origin, as well as having to recover high-purity hydrogen at the destination. These delivery methods may play a role in global shipping and exports of clean hydrogen from Texas ports.

2.3.2. Hydrogen Fueling Stations

Use of clean hydrogen in transportation applications, either to power fuel cells onboard electric vehicles or as a fuel for direct use in internal combustion engines, can provide substantial air quality benefits. These applications require vehicular technology modifications and dedicated hydrogen fueling stations. Hydrogen fueling stations are not common or publicly available in the United States, with the exception of California, so fueling stations and infrastructure to supply fuel to the stations need to be developed for Texas to be able apply clean hydrogen in long-haul trucking, light-duty vehicles, port drayage vehicles, and other vehicle types. Hydrogen fueling stations follow SAE International standards for refueling at either about 5000 psi (350 bar) or about 10,000 psi (700 bar) with pre-cooled hydrogen gas (e.g., J2601 for light-duty vehicles). Some technology developers are considering station designs that could dispense cryogenic liquid hydrogen that could be stored onboard heavy-duty vehicles in liquid form to extend range and be more compact so as not to reduce space for cargo.

Challenges for hydrogen fueling stations include reliability, dependence on hydrogen supply chains (as most stations are not co-located with hydrogen production), and capital and operating costs. As has been observed in California, coverage of costs is especially challenging when the market for hydrogen as a transportation fuel is nascent because fewer kg-H_2 are being sold daily over which to amortize fixed costs. With respect to meeting the H2@Scale levelized cost goal for dispensed hydrogen at $4/kg, the levelized cost of fueling stations is a substantial cost component in the early commercial market period before economies of scale can be realized. Increasing demand, improving reliability, and optimization of how hydrogen is supplied to the station can help address these challenges.

[27] https://www.energy.gov/eere/fuelcells/hydrogen-tube-trailers

2.3.3. Hydrogen Storage

The most economical forms of hydrogen storage, akin to hydrogen transportation and delivery, depend on the scale and capacity required. For small- to medium-scale storage (i.e., hundreds of kg to tens of tonnes), above-ground solutions can be considered, but for large "grid scale" energy storage (i.e., hundreds or thousands of tonnes), subsurface hydrogen storage is the most viable.

Above-ground storage options include gaseous and liquid storage, in pressure vessels and cryogenic spheres, respectively, which store hydrogen at similar pressures and temperatures to those used in gaseous and liquid truck deliveries.

Potential, commercially proven alternative methods of above-ground storage include the liquid hydrogen carriers of ammonia, methanol, etc., as well as the more developmental technology of solid (or liquid) metal hydrides. Benefits of these alternative forms of hydrogen storage include increased energy density, reduced storage pressures or degrees of refrigeration, and reduced parasitic energy consumption.

For hydrogen storage at very large scale, subsurface storage is almost always the most economical. Geologic storage in salt caverns solution-mined within salt domes or bedded salt formations is commercially proven. Although "salt dome" geology is not prevalent throughout much of the United States, it is found along the Texas Gulf Coast and used commercially today for storing hydrogen in Texas. Three large salt cavern geological storage facilities for hydrogen are in southeastern Texas, with a combined capacity of roughly 6 billion cubic feet (more than 10,000 tonne-H_2).[28] These facilities also include dedicated hydrogen pipelines to charge and discharge the storage caverns. Bedded salt formations with the prospect of being suitable for development of hydrogen storage caverns are found within the Permian Basin region.

3. The People Factor

In addition to the technical aspects for growing a hydrogen economy in Texas, the people and communities impacted must be considered. Any plan for development of hydrogen must include considerations of workforce development, economic and employment opportunities, and potential impacts (positive and negative) for environmental justice and disadvantaged communities. Federal hydrogen legislation and agency implementation policies since 2021–22 have prioritized engagement of a broad range community and provision of community benefits as part of demonstration and commercial "hub type" projects.

3.1. Hydrogen Policy

Policy can be a vital companion to technology development in deploying clean hydrogen infrastructure.[29]

[28] Netherlands Enterprise Agency, 2017, The effects of hydrogen injection in natural networks for the Dutch underground storages: contract report, publication no. RVO-079-1701/RP-DUZA, 66 p.
[29] John D. Graham, 2021, The Global Rise of the Modern Plug-In Electric Vehicle, Edward Elgar Publishing, Cheltenham, UK/Northampton, MA, USA.

Because the current costs of clean hydrogen are prohibitively high for many sectors and applications, policies and incentives are likely to be key factors in the pace of scale-up of the hydrogen economy. This section summarizes a time-stamped snapshot of Texas hydrogen (and related) policies to 2023, select federal and state policies, and potentially viable new policy options for Texas to support accelerated hydrogen infrastructure build-out and deployment.

3.1.1. Texas State Policy

More than two decades ago, Texas laid the groundwork to develop a hydrogen economy within the state.[30] In 2001, Texas passed a bill that directed the State Energy Conservation Office (SECO) to develop a statewide plan for accelerating the commercialization of fuel cells in Texas (House Bill 2845).[31] SECO's response eventually led to the development of the Texas Hydrogen Roadmap[32], released in 2009, which highlighted Texas' hydrogen production capabilities and leadership opportunities for hydrogen use in transportation. In 2005, a bill that directed the Texas Department of Transportation (TxDOT) to seek funding from public and private sources to acquire and operate hydrogen-fueled vehicles and establish and operate hydrogen-refueling stations passed, which required the development of the TxDOT Hydrogen Strategic Plan. This strategic plan for hydrogen also focused on transportation applications.[33] Despite sound analyses and well documented reports, neither bill provided any financial support and thus the recommendations were not implemented. Though developed in the early to mid-2000s, many of the roadmap and strategic plan's recommendations and insights on the potential role of hydrogen in Texas are still applicable today.

3.1.2. U.S. Infrastructure Investment and Jobs Act

The Infrastructure Investment and Jobs Act (IIJA), also referred to as the Bipartisan Infrastructure Law, authorizes $9.5 billion for clean hydrogen research, development, demonstration, and deployment (RDD&D), including $1 billion for electrolysis R&D, $500 million for hydrogen equipment manufacturing and recycling R&D, and up to $8 billion for development of Regional Clean Hydrogen Hubs.[34]

The Regional Clean Hydrogen Hubs will be administered by the U.S. Department of Energy (DOE) and are governed by several legislative requirements related to diversity of production, end-use, and geography. At least one hub must demonstrate hydrogen production from renewable energy, one from nuclear energy, and one from fossil fuel feedstocks. Further, at least one hub must demonstrate a hydrogen end use of residential and commercial heating, one with an end use of electric power generation, one with an end use of transportation, and one with an end use in the industrial sector. The hubs must be centered in a different region of the United States, with at least two hubs being based in natural gas producing regions.

[30] A.C. Lloyd, M.C. Lewis, and E.A. Adams, "Policy Drivers for Clean Hydrogen in Texas," Mitchell Foundation report, May 2022.
[31] https://capitol.texas.gov/BillLookup/History.aspx?LegSess=77R&Bill=HB2845
[32] "Texas Hydrogen Roadmap," Houston Advanced Research Center, with the support of Texas H2 Coalition, National Renewable Energy Laboratory, U.S. Department of Energy, 2009.
[33] R. Hebner, et. al., "TxDOT Strategic Plan for Hydrogen Vehicles and Fueling Stations," Report No.: Product 5590-P1, 2005.
[34] https://www.congress.gov/bill/117th-congress/house-bill/3684

The HyVelocity Gulf Coast Hydrogen Hub, based in the Houston region, was selected in October 2023 to enter into award negotiations with DOE. The Gulf Coast Hydrogen Hub plans large-scale hydrogen production using both natural gas with CCS and renewable-powered electrolysis, leveraging the Gulf Coast region's abundant energy resources, to reduce the unit cost of hydrogen. To help lower the cost of distribution and storage, as well as supply clean hydrogen to more users, the Gulf Coast Hydrogen Hub plans to develop salt cavern hydrogen storage, a large open access hydrogen pipeline, and multiple hydrogen refueling stations. The Gulf Coast Hydrogen Hub will use hydrogen for fuel cell electric trucks, industrial processes, ammonia synthesis, oil and petroleum products refining, petrochemical production processes, and marine fuel (e-methanol). The introduction of clean hydrogen into these industries is estimated to reduce CO2 emissions by 7 million tonnes per year.[35]

3.1.3. U.S. Clean Hydrogen Production Tax Credits

The Inflation Reduction Act, signed into law in August 2022, includes a clean hydrogen production tax credit. This new policy provides a credit of up to \$3/kg of "clean" hydrogen produced, providing that prevailing wage and apprenticeship requirements are also met.[36] The credit value varies based upon the emission intensity of produced hydrogen, essentially on a life-cycle basis through the point of production, as shown in Table 1. On December 26, 2023, the Internal Revenue Service (IRS) published a notice of proposed rulemaking for the Section 45V tax credit, with a due date for comments of February 26, 2024.[37]

Table 1. Clean hydrogen federal production tax credit (IRS section 45V) amounts and associated production emission intensity thresholds. Note that the given credit value assumes project eligibility for all bonus tax credit options.

Hydrogen Production Emission Intensity [kg-CO_2/kg-H_2]	Production Tax Credit Value [\$/kg-H_2]
0 - 0.45	\$3.00
0.45 - 1.5	\$1.00
1.5 - 2.5	\$0.75
2.5 - 4.0	\$0.60

3.1.4. U.S. Clean Trucks Rulemaking

The U.S. Environmental Protection Agency (EPA) is working on developing GHG emission standards for heavy-duty vehicles as part of the Clean Trucks Rule.[38] This proposed rulemaking aims to set new oxides of nitrogen emission standards for trucks starting in model year 2027 as well as update greenhouse gas emission standards to capture market shifts and new technologies available for zero-

[35] https://www.energy.gov/oced/regional-clean-hydrogen-hubs-selections-award-negotiations
[36] https://www.congress.gov/bill/117th-congress/house-bill/5376/text
[37] https://www.federalregister.gov/documents/2023/12/26/2023-28359/section-45v-credit-for-production-of-clean-hydrogen-section-48a15-election-to-treat-clean-hydrogen
[38] https://www.epa.gov/regulations-emissions-vehicles-and-engines/regulations-greenhouse-gas-emissions-commercial-trucks

emission vehicles in heavy-duty trucking. Hydrogen and fuel cells are expected to figure prominently in this transition. Once enacted as a federal regulation, it would apply to Texas.

3.1.5. California Low Carbon Fuel Standard

California adopted its Low Carbon Fuel Standard (LCFS) in 2009 as part of the state's efforts to reduce greenhouse gases.[39] The LCFS requires the reduction in the carbon intensity (in terms of CO2e per unit of fuel energy content) of transportation fuels by percentages that ratchet down over time. The 2020 requirement was 10% below the 2010 baseline. The 2030 requirement is 20% below the 2010 baseline. Clean hydrogen used as a low-carbon transportation fuel is a compliance option. Overcompliance results in a tradeable credit. The potential to export Texas-produced clean hydrogen to California, earning tradeable credits, could make the LCFS an important element in the economics of Texas project. Further, direct air capture projects sited anywhere in the world are eligible for LCFS credits. Such projects are being developed to supply CO2 to Permian Basin oilfield operators for EOR.

3.2. Policy Options for Texas

As noted, Texas is ideally suited to host public- and private-sector initiatives to demonstrate and commercialize clean hydrogen technologies to decarbonize the energy, industrial, and transportation sectors. The "market push" provided by federal support of capital projects through the IIJA is complemented by the "market pull" provided by the production tax credits of the Inflation Reduction Act. However, to best capitalize on federal funding opportunities, Texas may need to address potential uncertainties about which state regulatory agencies are responsible for overseeing the approval and permitting of new hydrogen infrastructure. Resolving such issues is a focus of industry-based nonprofit organizations, such as the Texas Hydrogen Alliance (THA). Having clear and actionable policies in place could speed clean hydrogen project development and technology deployment.

3.2.1. Facilitate Implementation of Clean Hydrogen Hub(s)

In September 2022, DOE released a funding opportunity announcement (DE-FOA-0002779) for the Regional Clean Hydrogen Hubs in the IIJA.[40] Multiple Texas teams applied for funding, building upon Texas' infrastructure and workforce base in the Houston and Gulf Coast area, to bring substantial federal dollars to projects in Texas to augment private sector and potentially state and local funds to build out a clean hydrogen infrastructure within the state. The private sector is already demonstrating a commitment to fund commercially viable projects involving hydrogen. As noted, in October 2023, DOE announced it had selected the HyVelocity Gulf Coast Hydrogen Hub to enter into award negotiations with the agency.

3.2.2. Potential Texas Incentive Policies

Based on its history of energy policies, Texas appears more likely to approach policymaking regarding clean hydrogen from an "incentives" perspective, rather than "command and control." Although regulations could emanate from federal requirements, comprehensive state-originated regulations such

[39] https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about
[40] https://www.energy.gov/oced/regional-clean-hydrogen-hubs-0

as California's Low Carbon Fuel Standard or Zero Emission Vehicle mandate, may not be replicated in Texas. However, examples of incentive policies that Texas could consider in support of federal and private sector initiatives include:

1. In providing funds, the Texas Commission on Environmental Quality could give priority to low income or otherwise challenged communities and increase the funds available per project.
2. Provide access to high-occupancy-vehicle lanes or provide toll-free access to toll roads for zero emission vehicles, such as hydrogen fuel cell electric cars and trucks.
3. Provide vouchers to encourage the purchase of zero-emission trucks to replace older, gross polluting vehicles.
4. Provide cost share funds for Texas-centric Regional Clean Hydrogen Hubs and other Texas applicants to similar competitive federal solicitations.
5. Provide state tax credits for zero-emission vehicle (ZEV) manufacturing and fuel production facilities.
6. State, counties, and/or cities waive sales and use tax for implementation/construction of ZEV fueling infrastructure.
7. Facilitate rights-of-way access priority for hydrogen pipeline installation.
8. Waive state vehicle registration fees for ZEVs until a given time, say 2030, or market penetration rate.
9. Support and facilitate acceleration of usage of liquid hydrogen rail tenders at the federal level.
10. Facilitate and support implementation of export terminals for Texas-produced hydrogen-based energy carriers.

3.3. Community Engagement and Benefits

Stakeholder and community engagement are key to public acceptance of new energy technologies, including clean hydrogen. In Texas, preliminary research has been conducted on the impact of clean hydrogen development on disadvantaged communities.

Continuing work is expected to involve engagement of nongovernmental organizations, businesses, and state and federal agencies representative of the variety of organizations with an interest in the issues where hydrogen projects may be developed. Initial efforts could focus on developing a better understanding of these issues in historically underserved communities and distressed communities, providing insight into how these communities may view clean hydrogen projects so that their concerns could potentially be addressed early in the project development cycle and with community benefits realized. An outreach campaign with education and question-and-answer sessions developed for the public, including local and environmental justice communities, could be a way to address issues and engage communities in clean hydrogen projects.

Various mapping tools and underlying data resources can help define and identify disadvantaged communities that can potentially benefit from clean hydrogen. An example is DOE's Energy Justice Mapping Tool – Disadvantaged Communities Reporter, which uses census tract data.[41] These tools and resources include the 99 census tracts in the Houston region that meet the criteria of a Qualified

[41] https://energyjustice.egs.anl.gov/

Opportunity Zone as defined by the state of Texas and the City of Houston.[42] Many of these communities would also meet the definition of an economically distressed community due to high unemployment rates, high mortgage foreclosure rates, and declining home prices. Another example is the Distressed Communities Index developed by the Economic Innovation Group, which uses similar criteria.[43] Figure 1 shows a map of Texas using a five-tier Distressed Communities Index.

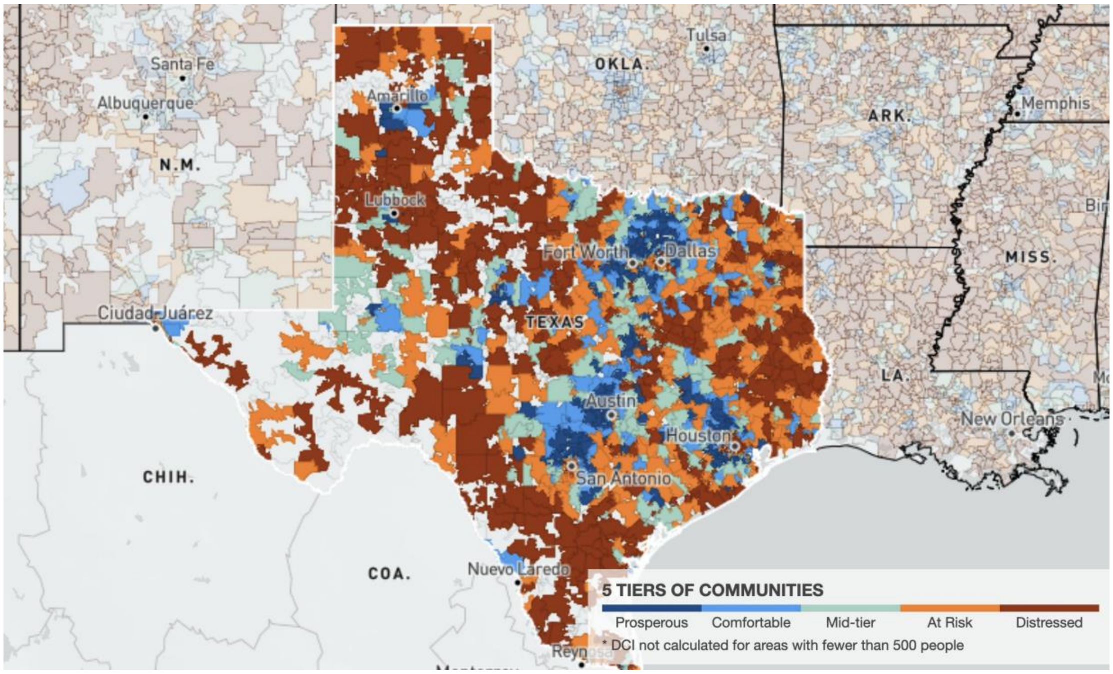

Figure 1. Map of Texas showing community status (Distressed Communities Index characterization) across the state based on five tiers of economic health used by the Economic Innovation Group.[44]

Definitions of communities for engagement will be further refined by building upon extensive research and knowledge developed for air quality, emissions, and public health analyses. For example, the Houston Advanced Research Center created overlays using the Center for Disease Control's Social Vulnerability Index data, which ranks census tracts on the basis of 15 social factors, including poverty, lack of vehicle access, and crowded housing.[45] Similarly, the Environmental Justice Indexes in EJScreen[46] developed by EPA reflect 11 environmental indicators, such as National Scale Air Toxics Assessment Air Toxics Cancer Risk, Traffic Proximity, and Volume or Proximity to Treatment Storage and Disposal Facilities.

In addition, there are other resources and web-based tools such as HGBEnviroScreen, which examines environmental justice issues in the Houston region and integrates and visualizes national and local data to address regional concerns across five domains:[47]

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[42] https://www.houstontx.gov/opportunityzones/index.html
[43] https://eig.org/distressed-communities/
[44] https://eig.org/distressed-communities/2022-dci-interactive-map/?path=state/TX
[45] https://www.atsdr.cdc.gov/placeandhealth/svi/index.html
[46] https://www.epa.gov/ejscreen
[47] https://hgbenviroscreen.org/

1. Social vulnerability
2. Baseline health
3. Environmental exposures and risks
4. Environmental sources
5. Flooding

These tools allow identification of the highest vulnerability census tracts that have multiple risk factors, with common drivers being flooding, social vulnerability, and proximity to environmental pollution sources. Building this fact-based approach will enable a framework to better assess the impact of clean hydrogen development on underserved communities.

Primary results of the developed model (discussed further in Section 4) will be a geospatially resolved build-out of new hydrogen infrastructure. Coupled with the environmental justice and disadvantaged community framework, impacts of potential project designs on communities can be assessed. For example, the model may build new electrolyzer facilities in a community that would benefit from the new jobs created by such a facility. Evaluating and understanding the impacts of model results and planned hydrogen projects on communities will be an important part of future work for regional hydrogen hub participants.

4. Framework for the Future

To investigate how Texas could expand the use of hydrogen throughout the state and leverage its resources and existing hydrogen infrastructure, the project team developed the Hydrogen Optimization with Deployment of Infrastructure (HOwDI) model. The model is a spatially resolved optimization framework that determines location-specific hydrogen production and distribution infrastructure to cost-optimally meet a specified location-based demand. This model allows users to explore how supporting infrastructure could develop to support potential near-term “actionable” hydrogen infrastructure development projects in Texas.

The optimization model maximizes system-level profit via the benefits realized from hydrogen consumption in various end-use sectors balanced with the costs of building and operating the required hydrogen infrastructure. The hydrogen infrastructure included in the model spans the entire hydrogen supply chain from production, distribution, and end-use delivery. The model includes costs associated with building fueling stations necessary to deliver hydrogen to meet heavy-duty transportation or industrial demand, but not the equipment required for the end use of hydrogen (e.g., hydrogen-fueled vehicles).

4.1. Overview of the HOwDI Model

The network model that forms the spatial basis for the infrastructure deployment optimization represents the geography of the Texas hydrogen system, including the hydrogen production and consumption at various hydrogen "hubs"[48] around the state, as well as the distribution path of hydrogen through the system. This enables realistic production and demand in different hubs, with pipelines or trucks to distribute supplies among them. Figure 2 provides a schematic representation of the network model logic and geographical area of consideration. At each hub, the model can build production, conversion, and/or distribution infrastructure to provide hydrogen for consumers.

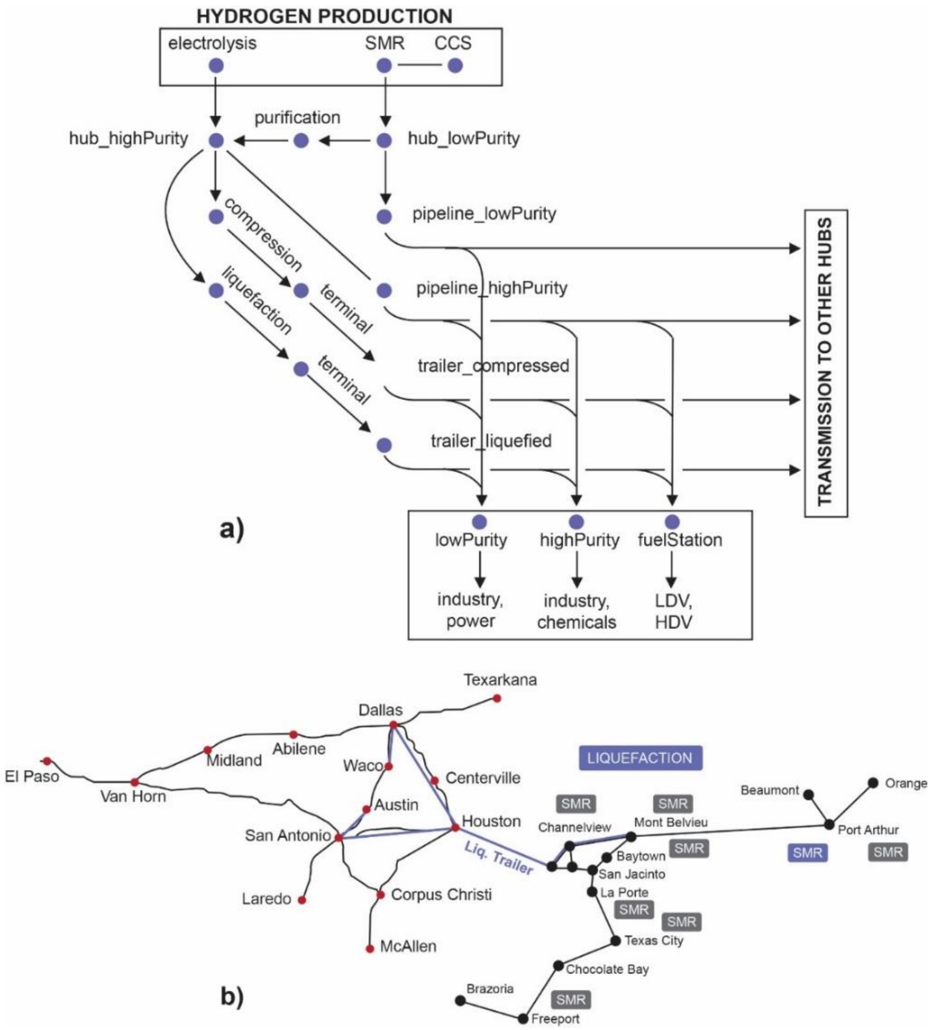

Figure 2. Schematic representation of the Hydrogen Optimization with Deployment of Infrastructure model demonstrating the a) network system of the model design and b) the geographical span of Texas and associated hubs included for model runs in this report. Black dots represent locations with existing hydrogen infrastructure; red dots represent locations with modeled new hydrogen demand.

Figure 3 shows a version of the results to demonstrate the model's capabilities for building hydrogen infrastructure across the state. In Figure 3, hubs with thermal production are noted with a red circle whereas hubs with electric production are denoted with a teal circle. Hubs with consumption but no production are noted with an open circle. The size of the symbols indicates the relative size of hydrogen

[48] In the terminology of the HOwDI model, "hubs" refers to locations across the state (often in cities) that serve as collections of nodes for hydrogen production, consumption, and distribution. This usage of the term "hubs" is distinct from the "hubs" proposed for funding under the DOE Regional Clean Hydrogen Hubs program.

production or consumption at each hub. The model also selects distribution infrastructure to connect between hubs (pipeline, liquid truck, or gas truck), which are indicated by different colored lines in the results.

Figure 3 shows the results for a singular model run (i.e., the optimal deployment of new infrastructure given a certain set of assumptions about infrastructure, energy, and feedstock costs, as well as assumptions for any policy-driven tax credits). Although these results are useful in understanding how and where hydrogen infrastructure might be built economically, there is a high level of uncertainty in some of the costs that were used for inputs. Thus, the project team added Monte Carlo methodology (simulation capability) to the model to address the uncertainty in the cost inputs and determine which input uncertainties had the greatest influence on the uncertainty in cost output variables (e.g., dispensed H_2 cost to fuel cell electric vehicles).

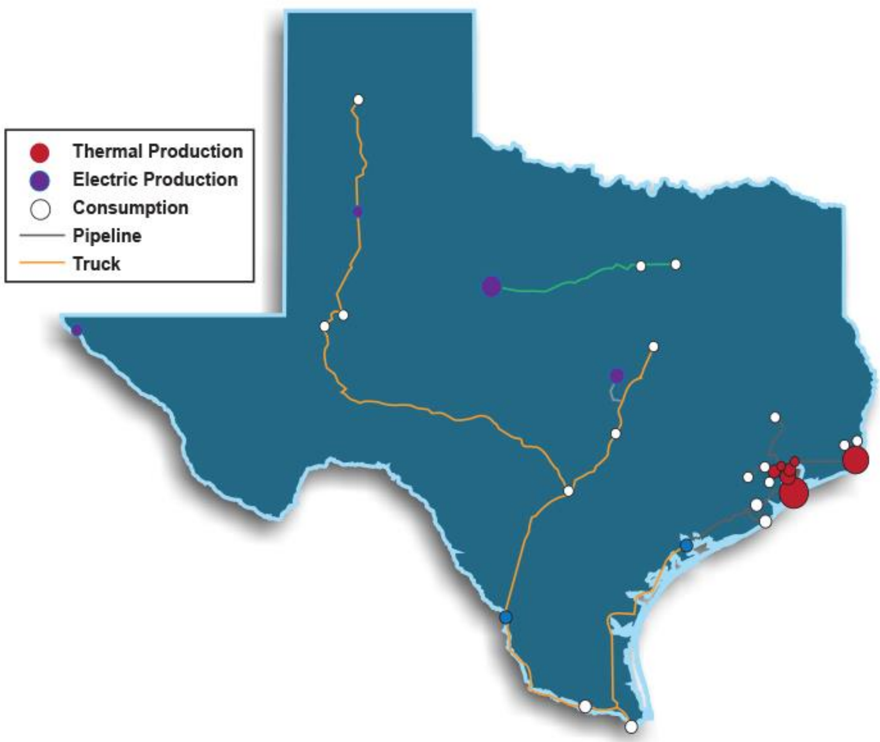

Figure 3. Sample outputs of model – spatially resolved hydrogen production and distribution infrastructure.

4.2. Monte Carlo Model Development

Because the model's linear formation results in short solution times, the modeling team parameterized the domain space and ran the model thousands of times via a Monte Carlo approach, which enabled the model to solve for many combinations of potential input costs and conditions. In each Monte Carlo run, a variable is randomly and independently chosen from each input distribution as an input into the HOwDI model and each of the HOwDI runs contributes to developing a distribution of outputs. The set of input and output distributions can then be analyzed to identify which input conditions led to the desired outputs, such as the levelized cost of hydrogen dispensed at the “fuel pump” being at or less than $4/kg-$H_2$. This model structure allows for the exploration of various pathways and scenarios and determines which model inputs are most important to achieving broader hydrogen deployment goals. Figure 4 provides a visual representation of the Monte Carlo simulation method with a subset of input cost variables and an example output cost distribution.

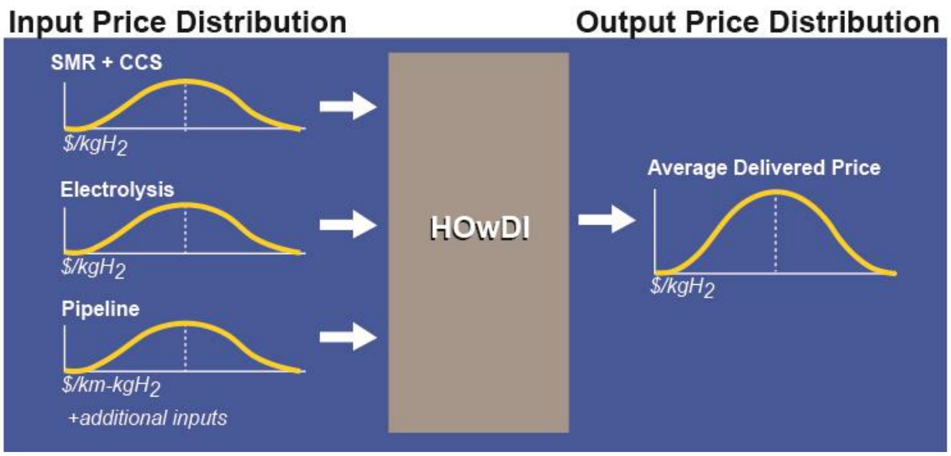

Figure 4. Demonstrative figure of the Monte Carlo simulation method showing sample distributions of model input variables and the resulting distribution for a sample output variable of interest.

The motivation for designing the model to run as a Monte Carlo simulation is to address the uncertainties associated with expected costs for hydrogen-related technologies that have not yet been built at scale. Because these costs come with significant uncertainties, it is unknown how well the model can reflect possible futures. Since the Monte Carlo model structure allows definition of a distribution and range of cost values, modelers can examine the effect of these price uncertainties over thousands of simulations, rather than relying on a single input value for each input parameter in a case study type model. Additionally, the input cost ranges can be set to reflect cost decline targets and expectations—for example, to align with DOE’s target for electrolyzer capital costs of $300/kW in 2025 and $150/kW in 2030[49]—and to explore the impact of realizing goals for delivered hydrogen cost.

4.3. Model Input Parameters

The model includes cost inputs for parameters across the hydrogen supply chain, including production, transportation, conversion, and distribution. A subset of the cost inputs was varied with each run during the Monte Carlo simulation scenarios. The varied cost parameters were selected because they are either inputs that are expected to see significant cost declines in the future, such as electrolyzer capital cost (CAPEX), or there is significant uncertainty in current costs, as in the case of fuel dispensers. Each parameter was assumed to vary based on a normal distribution. The Monte Carlo input parameters, mean (average), and standard deviation are given in Table 2. Variables that are in reality linked were also linked for the Monte Carlo variation. For example, the model has inputs for three different types of SMR production facilities: SMR, SMR + 60% CCS, and SMR + 90% CCS. Although each of these has a

[49] https://www.energy.gov/eere/fuelcells/articles/us-department-energy-hydrogen-activities-and-hydrogen-shot-overview-fc-expo

different base capital cost, the variation from this base was kept the same for the three technologies in each of the Monte Carlo runs such that if the unabated SMR capital cost was 0.8 times its mean for a Monte Carlo run, the SMR + 60% CCS and SMR + 90% CCS capital costs were also 0.8 times their means. Similar linked distributions were also applied to the electrolyzer capital cost, natural gas price, and electricity price.

Table 2. Input parameters and respective value for Monte Carlo simulations.

Parameter	Mean	St dev	Unit	Notes
Pipeline - CAPEX	3,000,000	± 25%	$/km	
Compressed Hydrogen Truck - CAPEX	600,00	± 20%	$/truck	
Liquefied Hydrogen Truck - CAPEX	1,000,000	± 20%	$/truck	
Liquefaction Facility - CAPEX	2,500,000	±20%	$/ton/day	
Fuel Station CAPEX (gas)	15,000,000	± 25%	$/ton/day	
Fuel Station CAPEX (liquid)	10,000,000	± 25%	$/ton/day	
Fuel Station CAPEX (pipeline)	5,000,000	± 25%	$/ton/day	
Electrolyzer - CAPEX	1,000	± 25%	$/kW	
Steam Methane Reformer - CAPEX	2,000,000 - 4,300,000	± 25%	$/ton/day	dependent on capture rate
Electricity Price	0.039 - 0.055	± 25%	$/kWh	spatially dependent
Natural Gas Price	4.004 - 4.657	± 25%	$/mmBtu	spatially dependent

In addition to cost inputs, the model also considers several key technical specifications of the various hydrogen technologies including electrolyzer electrical efficiency and CCS capture rates. Additionally, the model allows for inclusion of financial policy “levers,” including tax credits for carbon capture (such as the IRS Section 45Q credit value of $85/tonne-$CO_2$ captured),[50] the clean hydrogen production tax credit (IRS Section 45V), and a carbon price.

The model also considers various input demand scenarios, with demand specified at each hub and categorized by end-use type (i.e., existing, transportation, industrial, etc.) and carbon-sensitivity (whether the end consumer is specifically demanding clean hydrogen). Demand scenarios are set by the user and allow the model to be used to evaluate the impact of varying demand scenarios on infrastructure build-out.

The model results shown are from a transportation demand scenario that adds, in addition to existing industrial hydrogen demand, new demand in the heavy-duty transportation sector across Texas. Expected hydrogen demand was estimated using 2019 fuel consumption values for heavy-duty vehicle transportation mode in Texas and assuming a 25%, by energy content, replacement of heavy-duty transportation fuel.[51] The twenty largest hubs by population considered in the model were assigned this

[50] https://www.iea.org/policies/4986-section-45q-credit-for-carbon-oxide-sequestration
[51] https://tedb.ornl.gov/wp-content/uploads/2022/03/TEDB_Ed_40.pdf

demand, weighted based on hub population size. This was done to reflect the likelihood that hydrogen fueling stations will be installed in large population centers for initial hydrogen deployments.

4.4. Modeling Results

High-level results from Monte Carlo scenarios analyzed by the project team follow. A scenario refers to the Monte Carlo results composed of multiple individual HOwDI model runs. For most of the below results, each individual Monte Carlo scenario is composed of 1000 HOwDI model runs. The project team chose 1000 HOwDI model runs for each Monte Carlo scenario because the results indicated that for the same distributions of inputs, the output distributions of results of multiple Monte Carlo scenarios were very similar. This result indicated that 1000 HOwDI model runs in each Monte Carlo scenario captured a similar range of inputs and outputs.

The scenarios were designed to study the influence of various technologies and policies on the cost of hydrogen dispensed at fueling stations across Texas. The HOwDI scenarios included in this study are:

- **Baseline**: no policy or carbon constraints (business as usual)
- **Low Carbon**: all new hydrogen production built restricted to low-carbon technologies
- **Tax Credits**: any new hydrogen production allowed with inclusion of hydrogen and carbon capture tax credits for eligible technologies
- **Zero Carbon**: all new hydrogen production built restricted to zero-carbon technologies (electrolysis powered with renewable energy)
- **Zero Carbon Tax Credits**: all new hydrogen production built restricted to zero-carbon technologies (electrolysis powered with renewable energy) with inclusion of hydrogen and carbon capture tax credits
- **Zero Carbon with Direct Air Capture (DAC) offsets**: all new hydrogen production built restricted to zero-carbon technologies with inclusion of option to “offset” remaining emissions with direct air capture to meet zero-carbon threshold
- **Zero Carbon with DAC offsets and tax credits**: all new hydrogen production built restricted to zero-carbon technologies with inclusion of option to “offset” remaining emissions with direct air capture to meet zero-carbon threshold and with inclusion of hydrogen and carbon capture tax credits

The model results and system implications of each scenario are reported.

4.4.1. Baseline Monte Carlo Scenario Results

The baseline analysis consisted of running the Monte Carlo simulation with all possible technologies available to the model to determine which input cost variables were most correlated with achieving an average levelized price of ≤\$4/kg to deliver hydrogen to fuel cell trucks or vehicles at the fueling stations across all hubs in Texas. This scenario does not include any tax credits or other types of policy drivers. There is also no preference for or requirement to deliver hydrogen that is low or zero-carbon. The team also assumed that the model is free to build any hydrogen generation technology at every location. For this scenario, the team focused solely on deploying infrastructure for meeting the assumed heavy-duty trucking demand. Figure 5 shows a distribution of the cost of delivered hydrogen (dispensed to vehicle) for all 1000 model runs that make up the baseline scenario.

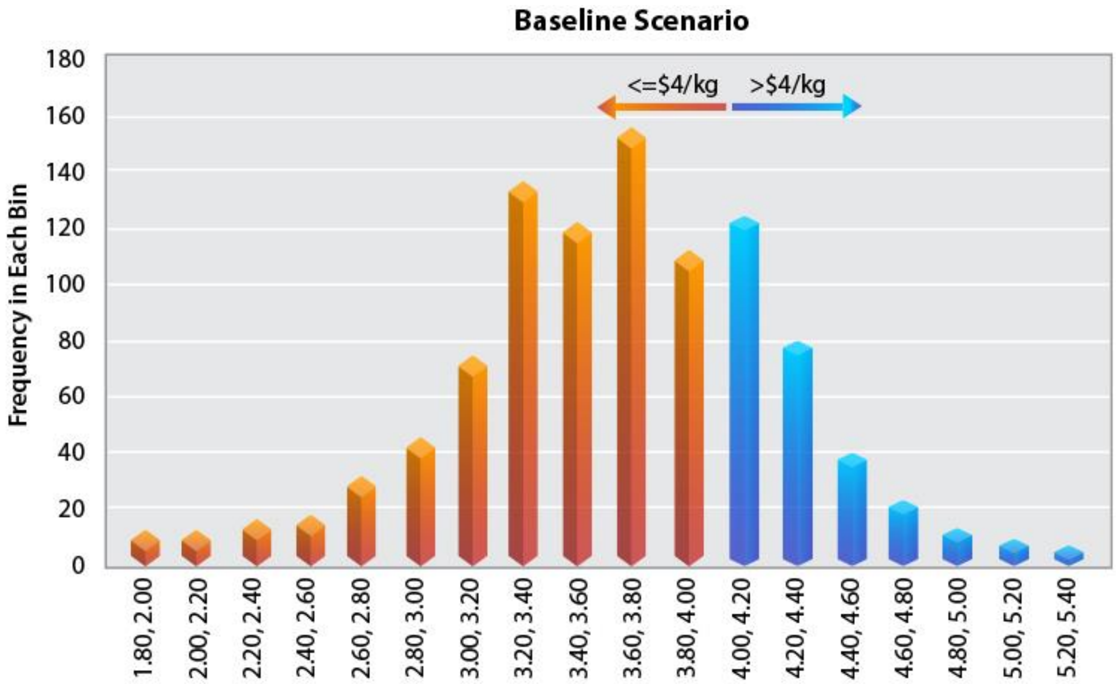

Figure 5. Figure showing the distribution of outputs of the weighted average dispensed cost ($/kg) of hydrogen at the pump for the Baseline Monte Carlo Scenario. The orange bars contain scenarios where the resulting average cost of dispensed hydrogen was less than or equal to $4/kg and the green bars contain scenarios where the resulting average cost of dispensed hydrogen was greater than $4/kg.

In this scenario, about 71% of runs resulted in an average dispensed hydrogen cost of $4/kg or less (at the pump). The average of the weighted average dispensed hydrogen cost for all 1000 runs was about $3.67/kg. All but 10 runs in this scenario resulted in the deployment of new SMR units without any kind of carbon capture. The only time that the model chose to deploy electrolysis for the majority of hydrogen production in lieu of SMR was for runs where SMR costs were very high and electrolysis costs were very low, relative to their respective distributions. There was only one run of the 1000 where the model built roughly equal amounts of new SMR and electrolysis.

However, about 80% of the HOwDI runs in the baseline Monte Carlo scenario deployed at least small amounts of new electrolysis units, corresponding to roughly 1-2% of new demand. The model chose this pathway for a few reasons. The project team assumed that the smallest SMR that could be built was for 100 tonnes of hydrogen per day, but the model could build smaller electrolyzers, down to 1 tonne of hydrogen per day. For example, in this analysis, Odessa, Texas, was assumed to only have a demand of about 19 tonnes of hydrogen per day. Thus, it was most often cheaper to deploy more expensive electrolyzers in such locations with smaller demand than to either build a 100 tonne/day SMR unit and utilize only 20% of its capacity or to bring in hydrogen from another location via truck or pipeline.

The remaining 20% of HOwDI runs that did not deploy any new electrolysis units and relied solely on new SMR systems adopted a mix of strategies to deliver hydrogen, including deploying SMR units that were utilized less than 50% of the time in some locations as well as a mix of pipelines and (mostly) liquid truck routes. These runs yielded a slightly higher average dispensed hydrogen cost of about $3.70/kg.

Some of the variables used in the Monte Carlo scenario were more influential than others in reaching the goal of ≤$4/kg. Table 3 shows the results of a correlation analysis between each of the input variables used in the Monte Carlo scenario and whether the individual HOwDI model run resulted in a dispensed cost of hydrogen ≤$4/kg. A positive correlation coefficient indicates that a reduction in the cost of that input is positively correlated with achieving a dispensed cost of hydrogen that is ≤$4/kg at the pump.

A correlation coefficient is a statistical measure of the strength of a linear relationship between the relative movements of two variables.[52] In Table 3, a positive correlation coefficient value indicates that a reduction in the cost of that input is positively correlated with achieving a dispensed cost of hydrogen that is less than or equal to $4/kg at the pump.[53] For example, the 0.68 correlation coefficient associated with the fuel station capital cost (pipeline fed) variable indicates that as the price of a pipeline-fed fueling station declines, it is more likely that the run will result in delivering a final cost of ≤$4/kg at the pump.[54]

Table 3: Table showing the correlation coefficients of each of the Monte Carlo variables for the Baseline Scenario with the average cost of hydrogen at the pump of less than or equal to $4/kg. A positive correlation coefficient indicates that a reduction in the cost of that input is positively correlated with achieving a dispensed cost of hydrogen that is less than or equal to $4/kg at the pump.

Variable	Correlation Coefficient
SMR + CAPEX	**0.18**
Electrolyzer CAPEX	-0.01
Pipeline CAPEX	0.03
Truck CAPEX (compressed gas)	0.00
Truck CAPEX (liquefied gas)	0.00
Fuel Station CAPEX (gas fed)	0.05
Fuel Station CAPEX (liquid fed)	-0.02
Fuel Sation (pipelline fed)	**0.68**
Liquefaction CAPEX	-0.03
Natural Gas Price	**0.23**
Electricity Price	-0.01

This scenario indicates that, of the variables considered in the baseline Monte Carlo scenario, the fuel station capital cost (pipeline fed) variable (0.68) had the strongest influence on achieving the $4/kg target. The second strongest influence was the price of natural gas (0.23), followed by SMR capital cost (0.18). Because the overwhelming majority of optimal HOwDI runs deployed SMR for the majority of their hydrogen production, it is understandable that that pathway's components would have the largest impact on the final delivered cost of hydrogen. However, because the model prefers to build hydrogen generation infrastructure close to the point of consumption, focusing R&D funding on reducing the cost of fueling stations might have the largest impact in achieving the $4/kg at the pump target.

[52] https://www.investopedia.com/terms/c/correlationcoefficient.asp
[53] This variable was coded as a binary, either a zero or a one, to mark whether the final average price was $4/kg or not.
[54] A fueling station that is fed directly from a pipeline and does not receive trucked deliveries of hydrogen.

In this scenario, the other variables appear to have little to no correlation with achieving the $4/kg target. One reason that a variable might not be correlated with the $4/kg target is that the HOwDI model never chose that option in the optimization of infrastructure. For example, fuel stations that are fed by gaseous truck deliveries (fuel station capital cost, gas fed) are generally much higher in cost relative to the other options and rarely, if ever chosen, so their changing capital cost would have little influence on the results.

Although the baseline scenario yields many pathways to the delivered cost target, most of the hydrogen is produced via SMR, which emits CO_2 during the process of reforming natural gas into hydrogen. Thus, modelers ran another scenario where the model was restricted to solely building low-carbon options.

4.4.2. Low Carbon Monte Carlo Scenario Results

In the Low Carbon Monte Carlo scenario, the ability of the model was limited to building new low-carbon hydrogen generation technologies to meet new hydrogen demand. In this scenario, each individual HOwDI run could build new hydrogen production units that have a life-cycle carbon intensity of 4 kg-CO_2/kg-H_2 or less. This emission threshold was selected because it is the highest allowable emissions for several low-carbon hydrogen policies currently being considered in the United States, including the regional clean hydrogen hubs and clean hydrogen production tax credits. This model run includes grid-fed electrolyzers at 65% utilization[55] (3.6 kg-CO_2/kg-H_2), SMR with 90% CCS (0.9 kg-CO_2/kg-H_2), and electrolysis paired with renewable energy only (0 kg-CO_2/kg-H_2). For reference, unabated SMR produces about 9 kg-CO_2/kg-H_2.

Figure 6 shows a distribution of the dispensed cost of hydrogen for all 1000 model runs that make up the low carbon scenario.

In this scenario, about 31% of runs resulted in an average dispensed hydrogen (at the pump) cost of ≤$4/kg. The average of the weighted average dispensed cost of hydrogen at the pump across the 1000 runs was about $4.35/kg. As in the baseline scenario, the majority of the runs in the low-carbon scenario deployed SMR for new hydrogen generation, although all of the new SMR units were limited to those with 90% CCS. In only 32 of the 1000 runs was the majority of hydrogen produced with new electrolysis units. But, similar to the baseline scenario, the majority (~90%) of the runs deployed some electrolysis for servicing locations with demand levels smaller than the capacity of the smallest SMR unit.

Because of the similarity in the results to the baseline scenario, the same variables that were more highly correlated with achieving the target $4/kg in the baseline results are more highly correlated in the low-carbon results. Table 4 shows the results of the correlation analysis between each of the input variables used in the Monte Carlo scenario and whether the individual HOwDI model run resulted in a dispensed cost of hydrogen ≤$4/kg.

[55] Previous analysis of grid-tied electrolysis in Texas (see additional readying materials) showed that for a utilization of 65%, marginal emissions of the electricity and associated hydrogen production emissions would be 3.6 kg CO_2/kg H_2.

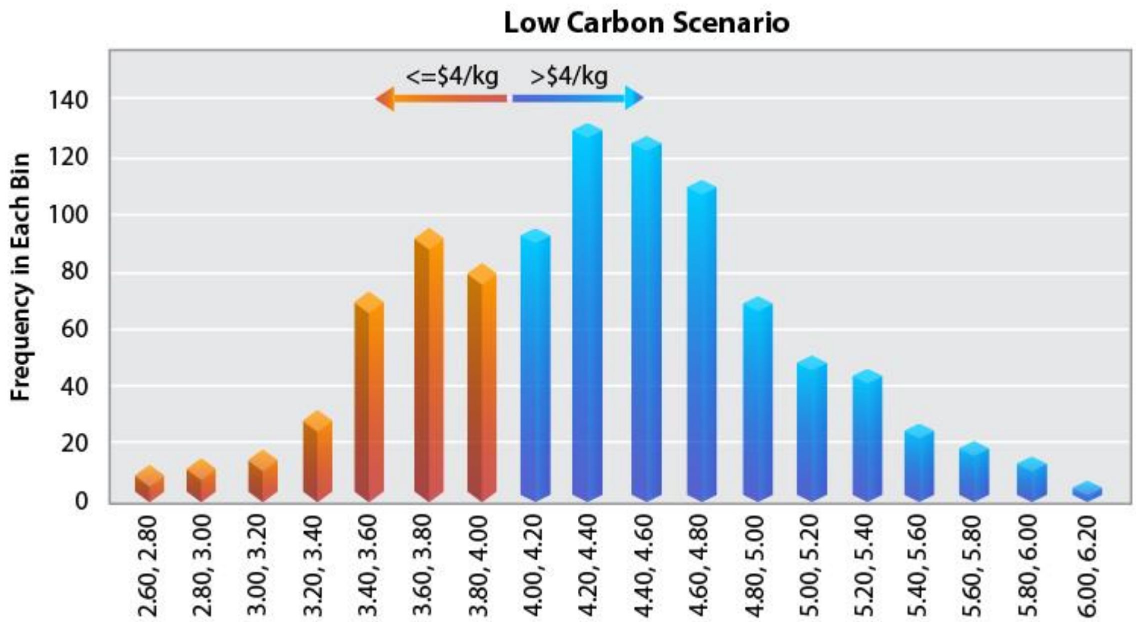

Figure 6. Figure showing the distribution of outputs of the weighted average dispensed cost ($/kg) of hydrogen at the pump for the Low Carbon Monte Carlo Scenario.

Table 4: Table showing the correlation coefficients of each of the Monte Carlo variables for the Low Carbon Scenario with the average cost of hydrogen at the pump of less than or equal to $4/kg.

Variable	*Correlation Coefficient*
SMR + CCS CAPEX	**0.37**
Electrolyzer CAPEX	0.07
Pipeline CAPEX	0.03
Truck CAPEX (compressed gas)	0.02
Truck CAPEX (liquefied gas)	0.00
Fuel Station CAPEX (gas fed)	0.10
Fuel Station CAPEX (liquid fed)	-0.07
Fuel Sation (pipelline fed)	**0.66**
Liquefaction CAPEX	-0.02
Natural Gas Price	**0.25**
Electricity Price	0.07

In the low-carbon scenario, the biggest influencer of whether the run achieved the $4/kg target was the fuel station capital cost (pipeline fed) (0.66), followed by SMR + CCS capital cost (0.35), and the price of natural gas (0.25). The capital cost of electrolysis and the price of electricity appear to be weakly correlated (0.07), which is plausible, but could also be within the “noise level” of the model outputs.

4.4.3. Tax Credits Monte Carlo Scenario Results

In this scenario, the project team incorporated tax credits potentially available for low-carbon hydrogen production methods based on their life-cycle GHG emissions. Each model run was able to choose to build any available technology, even if it didn't qualify for tax credits. The tax credits serve to lower the cost of hydrogen production from certain low-carbon technologies. The two tax credits considered were the IRS Section 45Q tax credit for carbon sequestration and the 45V clean hydrogen production tax credit. SMR with CCS facilities were able to take the 45Q credit value (based on the amount of CO_2 captured) or the 45V credit (based on the amount of hydrogen produced and the respective carbon intensity of that hydrogen production) at each of their respective levels. The two production technologies that qualified for tax credits were SMR with 90% CCS, grid-fed electrolysis with reduced capacity factor, and electrolysis that ran exclusively on renewable energy.[56] Figure 7 shows a distribution of the delivered price of hydrogen for all 1000 model runs that make up the tax credits scenario.

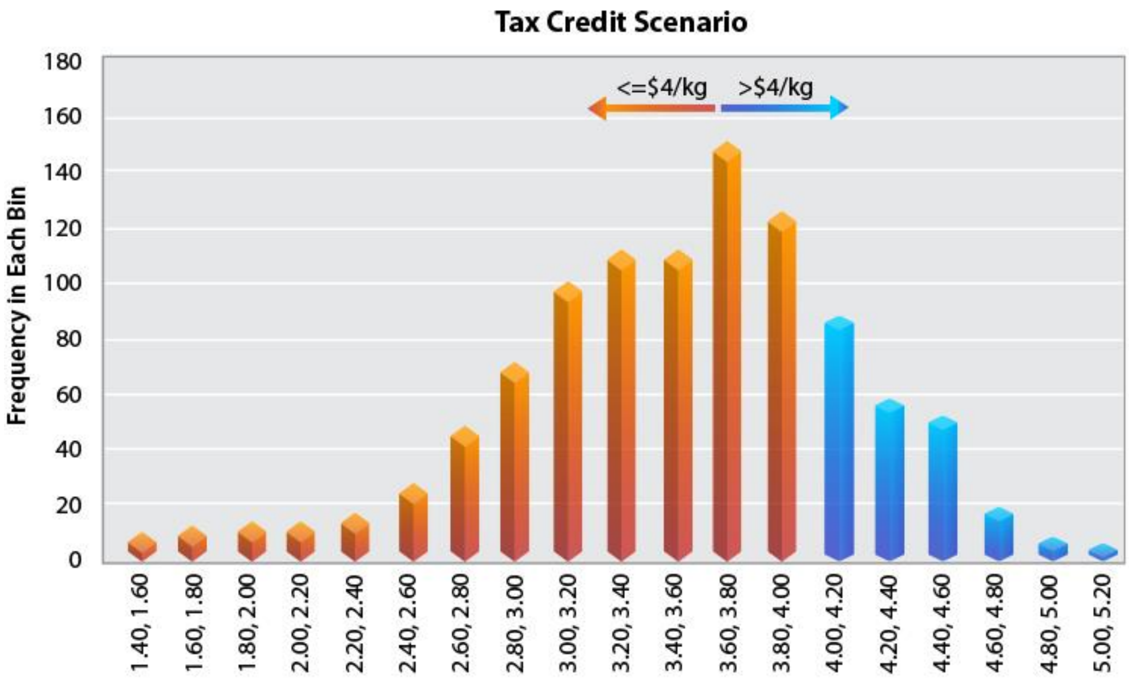

Figure 7. Figure showing the distribution of outputs of the weighted average dispensed cost ($/kg) of hydrogen at the pump for the Tax Credit Monte Carlo Scenario.

In this scenario, about 77% of the model runs resulted in achieving the ≤$4/kg goal, with an average dispensed cost of about $3.55/kg. However, only about 43% of the runs deployed a majority of technologies that qualified for the tax credits. Of those runs that deployed technologies that qualified for tax credits, only 86 deployed a majority of new electrolysis units and about 340 deployed SMR with 90% CCS. These results suggest that the tax credits play an important role in bringing clean hydrogen costs on par with unabated SMR. The rest of the runs in this scenario generally deployed SMR without CCS,

[56] Modeled by forcing the electrolysis + renewable energy to have a 40% capacity factor whereas it was assumed that grid-fed electrolysis would have a 90% capacity factor in the baseline scenario or a 65% capacity factor in the low-carbon scenario.

often paired with grid-fed electrolysis for locations with small demands. Given the similar technology deployments as in other scenarios, the correlation analysis is roughly the same as well, with the largest correlations (with meeting the $4/kg target) associated with fuel station capital cost (pipeline fed) (0.62), SMR + CCS capital cost (0.25), and the price of natural gas (0.18), as shown in Table 5.

Table 5: Table showing the correlation coefficients of each of the Monte Carlo variables for the Tax Credit Scenario with the average cost of hydrogen at the pump of less than or equal to $4/kg.

Variable	*Correlation Coefficient*
SMR + CCS CAPEX	**0.25**
Electrolyzer CAPEX	0.05
Pipeline CAPEX	0.01
Truck CAPEX (compressed gas)	0.04
Truck CAPEX (liquefied gas)	0.03
Fuel Station CAPEX (gas fed)	0.03
Fuel Station CAPEX (liquid fed)	0.06
Fuel Sation (pipelline fed)	**0.62**
Liquefaction CAPEX	-0.07
Natural Gas Price	**0.18**
Electricity Price	0.08

Although the tax credit scenario resulted in more scenarios that meet the $4/kg target than the low-carbon scenario, the majority of scenarios were not low-carbon. The next few scenarios require that all new hydrogen be generated by zero-carbon technologies.

4.4.4. Zero Carbon Monte Carlo Scenario Results

The first zero-carbon scenario incorporated no tax credits and essentially limited the ability of the model to building only electrolysis units powered solely by renewable energy. Renewable electricity electrolysis build locations were restricted to regions with high renewable resource potential and low population density to simulate the practical considerations of where electrolyzers could be built powered by dedicated renewables. Figure 8 shows the histogram of delivered hydrogen prices seen by the model.

This scenario indicated that the model was not able to deliver hydrogen at the $4/kg target for any run in this scenario. The average dispensed cost was about $8.32/kg. As such, a correlation analysis for this scenario was not included. The next scenario is the same, except that the model was allowed to take advantage of available federal tax credits.

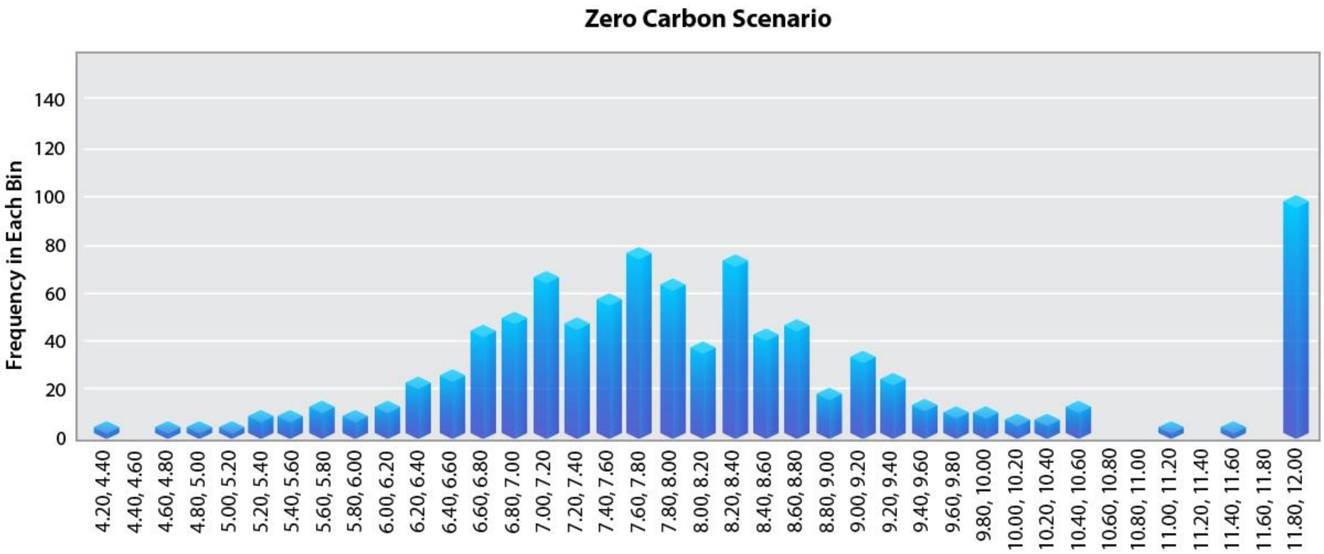

Figure 8. Figure showing the distribution of outputs of the weighted average dispensed cost ($/kg) of hydrogen at the pump for the Zero Carbon Monte Carlo Scenario. All runs in the zero-carbon scenario resulted in dispensed hydrogen greater than $4/kg. The bar on the far right side of the histogram includes all runs where the cost was greater than $12/kg.

4.4.5. Zero Carbon with Tax Credits Monte Carlo Scenario Results

The zero-carbon with tax credits scenario still limited the ability of the model to build only electrolysis units powered by renewable energy, which is the only strictly zero-carbon technology available. However, now the model was free to monetize the $3/kg-$H_2$ tax credit available from the Inflation Reduction Act. Figure 9 shows the distribution of dispensed costs in this scenario.

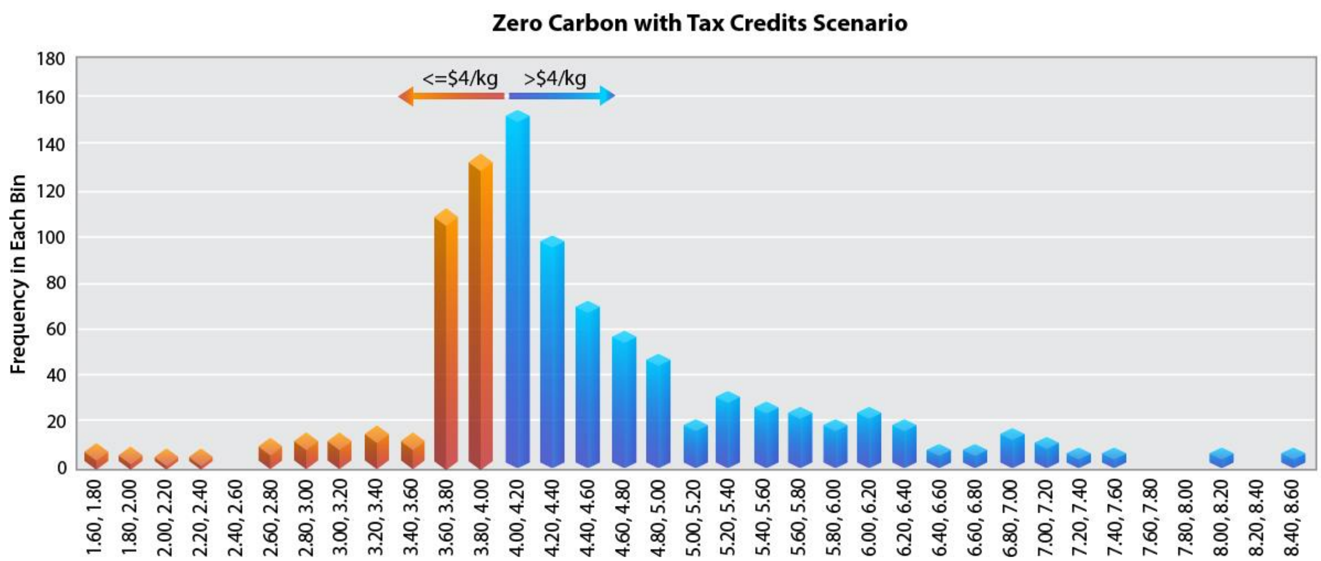

Figure 9. Figure showing the distribution of outputs of the weighted average dispensed cost ($/kg) of hydrogen at the pump for the Zero Carbon with Tax Credits Monte Carlo Scenario.

In the zero-carbon with tax credits scenario, the model was able to meet the $4/kg target in about 33% of the runs, with an average dispensed cost of about $4.48/kg. Because the model was only able to deploy new electrolysis units, this scenario was the first to yield significant correlations for electrolysis cost elements, shown in Table 6 below.

Table 6: Table showing the correlation coefficients of each of the Monte Carlo variables for the Zero Carbon with Tax Credits Scenario with the average cost of hydrogen at the pump of less than or equal to $4/kg.

Variable	*Correlation Coefficient*
SMR + CCS CAPEX	0.12
Electrolyzer CAPEX	**0.58**
Pipeline CAPEX	0.18
Truck CAPEX (compressed gas)	-0.02
Truck CAPEX (liquefied gas)	-0.06
Fuel Station CAPEX (gas fed)	-0.01
Fuel Station CAPEX (liquid fed)	0.00
Fuel Sation (pipelline fed)	**0.40**
Liquefaction CAPEX	-0.04
Natural Gas Price	0.14
Electricity Price	**0.32**

4.4.6. Zero Carbon with DAC Offsets Monte Carlo Scenario Results

In the zero-carbon with direct air capture (DAC) offsets scenario, the zero-carbon production options were expanded so that the model could choose between renewable energy powered electrolysis or SMR with 90% CCS paired with DAC to sequester the remaining 10% of emissions. DAC was not modeled directly but utilized a levelized cost of DAC from the International Energy Agency ($200/tonne-$CO_2$) converted to a per kg of hydrogen variable cost adder for the SMR unit.[57] This scenario did not consider any available tax credits. Figure 10 shows the distribution of delivered fuel costs for this scenario.

In the zero-carbon with DAC offsets scenario, the model can meet the $4/kg target about 20% of the time and results in an average dispensed cost of about $4.60/kg. In this scenario, the model chose to deploy the SMR with CCS+DAC option in 100% of the runs, only building electrolysis powered by renewable energy in locations with smaller demands, similar to previous scenarios.

Table *7* shows the correlation of input cost variables with output cost for this scenario.

In this scenario, the only two variables that appear to be correlated with achieving the $4/kg target are fuel station (pipeline fed) capital cost (0.60) and SMR + CCS capital cost (0.43). The correlation analysis doesn't indicate that the price of natural gas is correlated with the price of hydrogen, which could be explained by the fact that including the DAC variable costs in the model increased the variable costs of the SMR+CCS unit from $90/ton-$H_2$ to $270/ton-$H_2$, likely overwhelming the impact of changing natural

[57] https://www.iea.org/data-and-statistics/charts/levelised-cost-of-co2-capture-by-sector-and-initial-co2-concentration-2019

gas prices. The next scenario iterated on this scenario by incorporating the maximum clean hydrogen production tax credits available from the Inflation Reduction Act.

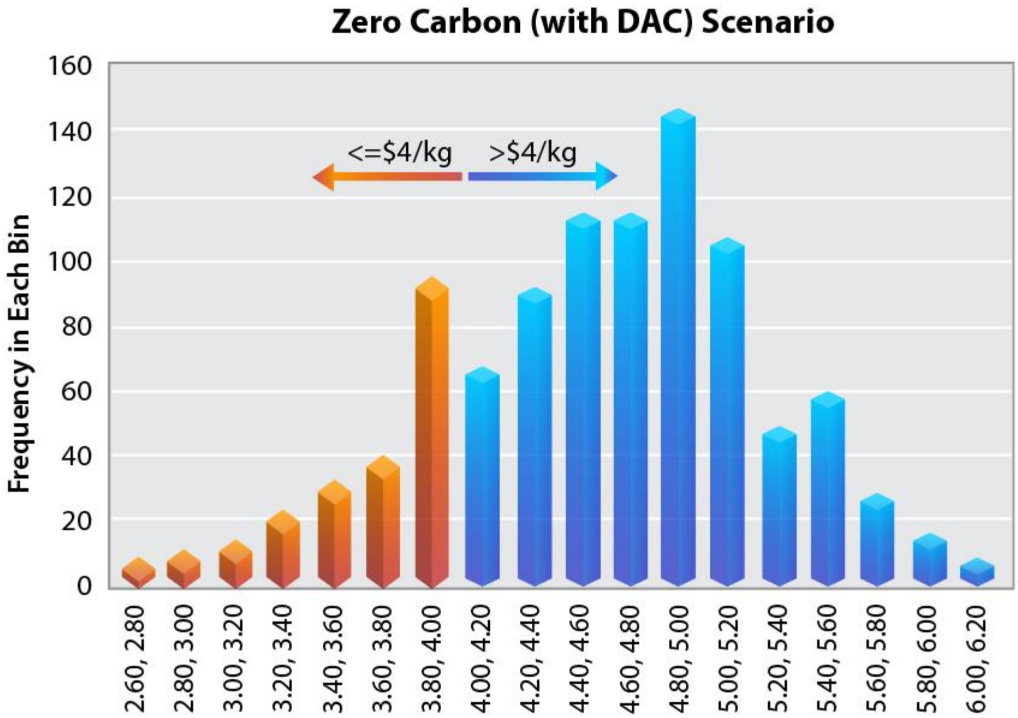

Figure 10. Figure showing the distribution of outputs of the weighted average dispensed cost ($/kg) of hydrogen at the pump for the Zero Carbon with DAC Offsets Monte Carlo Scenario.

Table 7: Table showing the correlation coefficients of each of the Monte Carlo variables for the Zero Carbon with DAC Offsets Scenario with the average cost of hydrogen at the pump of less than or equal to $4/kg.

Variable	Correlation Coefficient
SMR + CCS CAPEX	**0.43**
Electrolyzer CAPEX	0.01
Pipeline CAPEX	0.04
Truck CAPEX (compressed gas)	-0.03
Truck CAPEX (liquefied gas)	-0.00
Fuel Station CAPEX (gas fed)	-0.02
Fuel Station CAPEX (liquid fed)	-0.04
Fuel Sation (pipelline fed)	**0.60**
Liquefaction CAPEX	0.05
Natural Gas Price	0.02
Electricity Price	0.02

4.4.7. Zero Carbon with DAC Offsets + Tax Credits Monte Carlo Scenario Results

In the zero-carbon with DAC offsets + tax credits scenario, the project team assumed that the model had to build out zero-carbon technologies that could include renewable energy powered electrolysis or SMR with 90% CCS + DAC, similar to the zero carbon with DAC offsets scenario. In this scenario, both production technologies qualify for some form of tax credit. The research team assumed that the renewable energy powered electrolysis would qualify for an IRS Section 45V $3/kg clean hydrogen production tax credit and the SMR with CCS+DAC would qualify for the IRS Section 45Q tax credit based on the amount of CO_2 sequestered by the hydrogen production facility ($0.69/kg-$H_2$ based on a 90% capture of standard SMR emissions and $85/tonne CO_2 credit). SMR+CCS facilities were not able to count "offset credits" met by DAC (CO_2 emissions captured off-site and separate from the hydrogen production facility) to qualify for the highest tier of clean hydrogen tax credit. Figure 11 shows the distribution of dispensed hydrogen costs in this scenario.

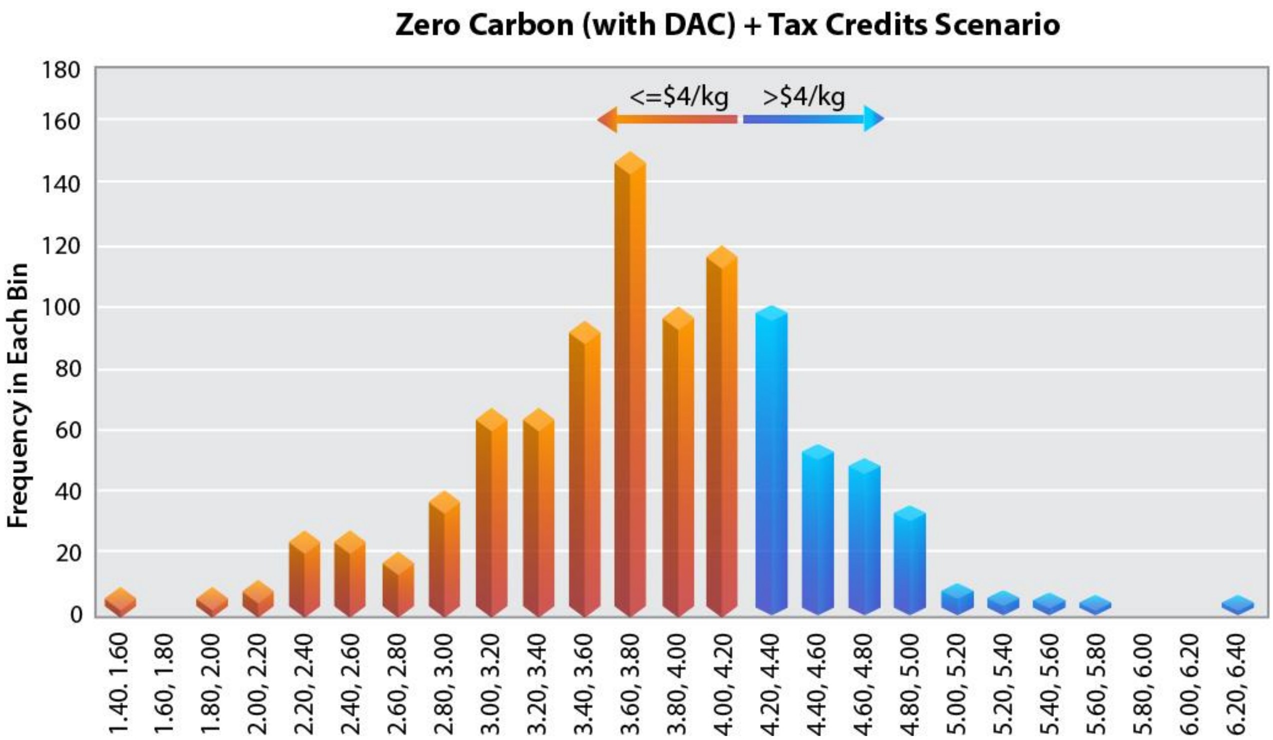

Figure 11. Figure showing the distribution of outputs of the weighted average dispensed cost ($/kg) of hydrogen at the pump for the Zero Carbon with DAC Offsets and Tax Credits Monte Carlo Scenario.

In the zero-carbon with DAC offsets + tax credits scenario, about 60% of runs resulted in achieving the $4/kg target, with an average dispensed cost of $3.79/kg across all runs in the scenario. Across the scenario's 1000 runs, about 144 runs deployed a majority of renewable energy powered electrolyzers, 92 runs deployed a roughly even mix of the two technologies, and the rest deployed a majority of SMR with CCS+DAC. This scenario produced the largest number of runs where the model deployed both technologies. Table 8 shows the correlation of the input cost variables with achieving the $4/kg target.

Table 8: Table showing the correlation coefficients of each of the Monte Carlo variables for the Zero Carbon with DAC Offsets and Tax Credits Scenario with the average cost of hydrogen at the pump of less than or equal to $4/kg.

Variable	Correlation Coefficient
SMR + CCS CAPEX	**0.30**
Electrolyzer CAPEX	0.17
Pipeline CAPEX	0.02
Truck CAPEX (compressed gas)	0.00
Truck CAPEX (liquefied gas)	-0.02
Fuel Station CAPEX (gas fed)	-0.01
Fuel Station CAPEX (liquid fed)	0.00
Fuel Sation (pipelline fed)	**0.65**
Liquefaction CAPEX	-0.10
Natural Gas Price	0.17
Electricity Price	**0.19**

In this scenario, the highest correlated variable to achieving the $4/kg fueling station target was the fuel station (pipeline fed) capital cost (0.65). The more even deployment of each hydrogen production technology resulted in both the SMR + CCS (0.30) and electrolysis (0.17) capital cost values, as well as their respective fuel prices: electricity (0.19) and natural gas (0.17), being correlated with achieving the $4/kg target.

4.4.8. Monte Carlo Scenario Results Summary

Table 9 is a summary of the results from the seven Monte Carlo scenarios analyzed by the project team.

Every scenario, except for the zero-carbon scenario without tax credits, resulted in at least 20% of the runs being able to meet the $4/kg-$H_2$ dispensed fuel cost target, indicating that many pathways exist for delivering hydrogen at the pump economically. In general, tax credits reduce the expected delivered cost of hydrogen, but are not always enough to incentivize the deployment of the technologies that they target: for example, the model often choose to deploy SMR without CCS even when tax credits were available for SMR with CCS or electrolysis.

No scenario deployed a majority of electrolysis units to meet new demand unless the scenario was restricted from deploying new SMR units via carbon constraints. Even at a levelized cost of $200/tonne-$CO_2$ for abatement by direct air capture, the model still showed a preference for that technology (as a "trim" to zero in conjunction with SMR + CCS) over renewable energy powered electrolysis. Across all scenarios that were able to dispense $4/kg hydrogen, all saw a strong correlation between the capital costs of fuel stations, in particular those that receive hydrogen via pipelines instead of liquid or gaseous trucks. Although some model runs saw a few truck routes or hubs connected via some short pipelines, the vast majority preferred to build hydrogen production facilities at the same location as the fueling station to minimize distribution costs.

Because most model runs across most of the scenarios deployed SMR-based technologies, the capital costs of SMR units as well as the cost of natural gas were often correlated with meeting the $4/kg dispensed fuel target. Only scenarios that required zero-carbon technologies or required zero-carbon technologies and included tax credits saw the deployment of meaningful levels of electrolysis. These scenarios showed correlations of meeting the $4/kg target with electrolyzer capital cost and the price of electricity.

Table 9: Table showing summary statistics of the various Monte Carlo scenarios.

Scenario Name	Scenario Number	Tax Credits	% runs ≤$4/kg	Average Dispensed Cost ($/kg)	Majority Deployed Technology	Most Correlated Variables
Baseline	8.3.1	No	71%	$3.69	SMR	Fuel station* & SMR CAPEX, NG price
Low carbon	8.3.2	No	31%	$4.35	SMR with CCS	Fuel station* & SMR CAPEX, NG price
Tax credits	8.3.3	Yes	77%	$3.55	SMR/SMR with CCS	Fuel station* & SMR CAPEX, NG price
Zero carbon	8.3.4	No	0%	$8.32	Electrolysis + RE	N/A
Zero carbon +tax credits	8.3.5	Yes	33%	$4.48	Electrolysis + RE	Fuel station* & SMR CAPEX, NG price
Zero carbon with DAC offsets	8.3.6	No	20%	$4.49	SMR with CCS+DAC	Fuel station* & SMR CAPEX
Zero carbon with DAC offsets +tax credits	8.3.7	Yes	60%	$3.79	SMR with CCS+DAC	Fuel station*, SMR & electrolysis CAPEX, electricity & natural gas price

Figure 12 shows the distribution of costs for key input parameters across a subset of Monte Carlo scenarios that resulted in a dispensed hydrogen cost of less than $4/kg at the fueling station. The three technologies with the highest correlation to delivered fuel cost are shown for each scenario. The input price has been normalized to the mean such that a value of 0 in Figure 12 represents an input value equal to the mean value of that input across all model runs in that Monte Carlo scenario. The mean cost of the input variables for the runs that delivered hydrogen for ≤$4/kg, in absolute terms, for each of these technologies, across multiple scenarios is shown in Table 10.

The range of input prices that yielded ≤$4/kg hydrogen across all technologies is very wide, which indicates that there are many pathways to achieving the cost target. For example, even in a run where fueling station costs remained high, decreases in SMR capital costs could still result in a competitive cost of delivered hydrogen. However, if the mean value of a given input for model runs that achieved the cost target was less than the mean of the full trial, this difference indicated a strong need to decrease costs of these technologies to deliver hydrogen at or below the cost target. The pipeline-fed fueling station capital cost mean was the lowest value for all scenarios except the Zero Carbon Tax Credits Scenario, reinforcing the observation that high fueling hydrogen costs are largely driven by high fueling station costs. For the Zero Carbon Tax Credits Scenario, the significant majority of all ≤$4/kg runs saw an electrolyzer capital cost well below the current mean value, indicating that decreasing electrolyzer capital costs is a key driver to reducing the cost of zero carbon hydrogen production and delivery. The Zero Carbon Scenario (without tax credits) is not included in Figure 12 because no runs resulted in a dispensed hydrogen cost of ≤$4/kg.

Although these model results are specific to a transportation demand scenario, there are relevant insights for hydrogen use across other sectors, such as power generation, industrial applications, and export. Across these scenarios, hydrogen production costs—both capital to build new facilities as well as feedstock costs—were highly correlated with the final delivered fuel cost. Reducing hydrogen production costs will allow hydrogen to be more competitive across sectors, including in industry, as a feedstock for ammonia for export, etc.

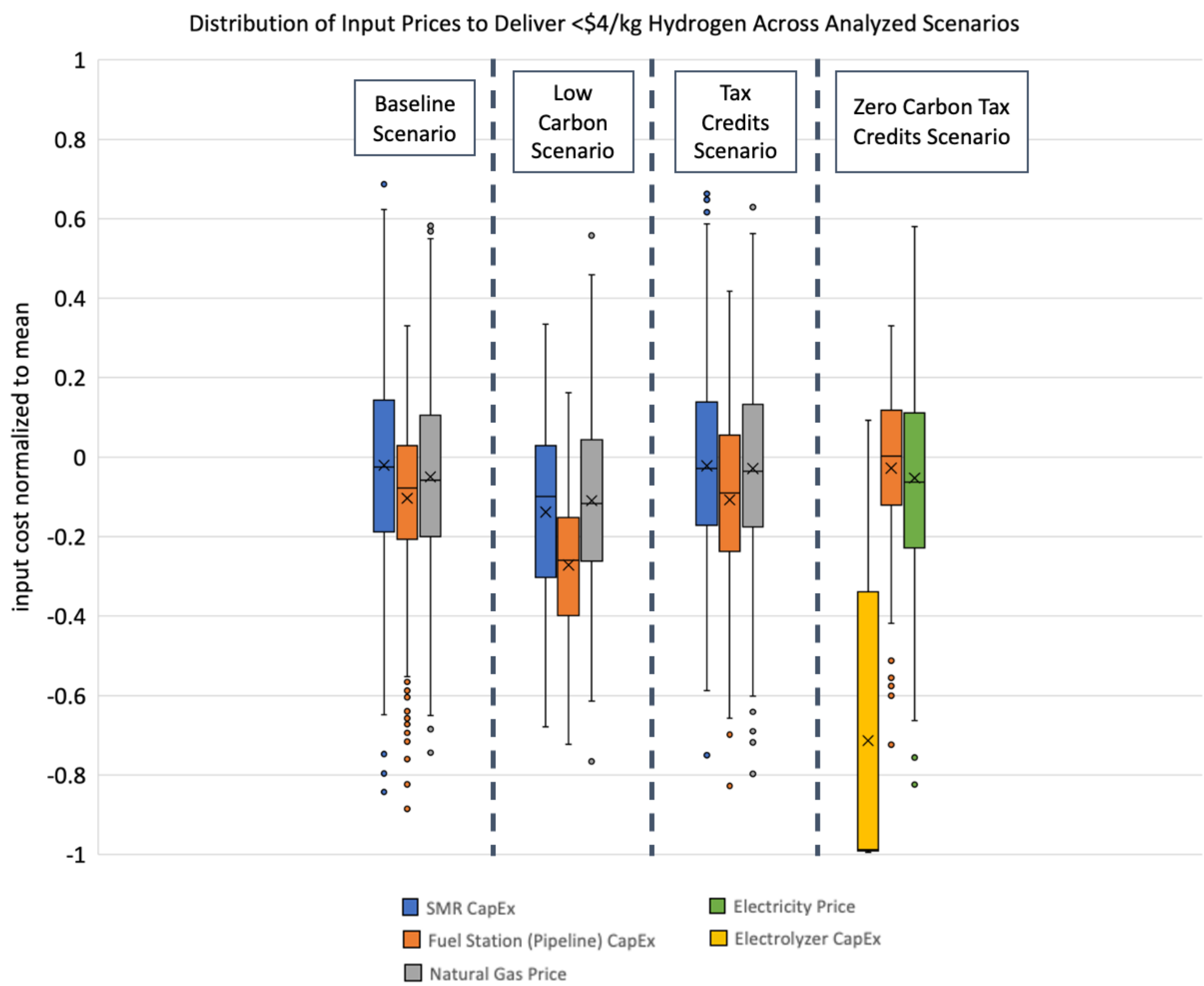

Figure 12. Distribution of input variable costs in runs that dispensed hydrogen <$4/kg across the analyzed scenarios. Input prices are shown normalized to the mean where a value of 0 on the vertical axis indicates the input mean cost for all Monte Carlo runs.

Table 10. Mean input price (in absolute terms) for runs that dispensed hydrogen <$4/kg for a subset of Monte Carlo scenarios for the three input prices with the highest correlation with dispensed hydrogen cost for that particular scenario.

Baseline Scenario	SMR CAPEX	1,959,380	$/ton-day
	Fuel Station (pipeline) CAPEX	4,483,493	$/ton-day
	Natural Gas Price	3.974	$/mmBtu
Low Carbon Scenario	SMR CAPEX	3.705,775	$/ton-day
	Fuel Station (pipeline) CAPEX	3,642,911	$/ton-day
	Natural Gas Price	3.725	$/mmBtu
Tax Credits Scenario	SMR CAPEX	4,206,173	$/ton-day
	Fuel Station (pipeline) CAPEX	4,462,334	$/ton-day
	Natural Gas Price	4.062	$/mmBtu
Zero Carbon Tax Credits Scenario	SMR CAPEX	287	$/kW
	Fuel Station (pipeline) CAPEX	4,862,839	$/ton-day
	Electricity Price	0.0435	$/kWh

5. Strategic Next Steps

In the context of existing hydrogen generation, distribution, demand, and infrastructure assets, as well as policy and community engagement, the project team and industry partners assessed what next steps could enable or accelerate the deployment of stationary and mobility applications using clean hydrogen in Texas, beginning with the Gulf Coast. With a focus on the five years ahead, in the context of both this H2@Scale project and the preparatory stage for implementing a Texas and Gulf Coast Clean Hydrogen Hub, the following representative scale-up project types were recommended.

5.1. Rollout Heavy-Duty Fuel Cell Trucks and Fueling Stations

The HOwDI model indicates that multiple pathways for cost-competitive clean hydrogen fueling stations to support FCEVs in Texas. These stations could first be built for medium- and heavy-duty trucks, as their fuel use is high due to hours of operation and many require range and refueling times that battery electric counterparts cannot satisfy. The HOwDI model showed a preference for fueling stations along hydrogen pipelines and existing hydrogen infrastructure, making the Gulf Coast region ideal, but it also found opportunities for fueling stations throughout Texas. Focusing on the Texas Triangle freight corridors could identify sufficient clean hydrogen demand to support deployment of hydrogen fueling stations and clean hydrogen production capacity.

To quantify this opportunity, characteristics of the Port Houston area could be used as a test case. Port Houston is the 7th largest container port in the United States with over 1.5 million containers imported at the two major container terminals of Barbour's Cut and Bayport. The Houston Ship Channel Industrial area is the nation’s busiest seaport complex, consisting of more than 200 public and private terminals, and it supports the nation’s largest petrochemical complex. Its four public container terminals handle over two-thirds of all U.S. Gulf Coast container traffic with 9000 daily truck visits. There are an additional 50,000 daily truck visits at the 200 privately owned terminals within the port, making this area an anchor for deploying clean hydrogen applications.

Additionally, it is the largest U.S. port in terms of tonnage. About 25% of these containers are moved by trucks to Dallas and beyond on I-45. Over 15,000 medium- and heavy-duty trucks travel on this route daily. Connecting Houston-Galveston and Dallas-Fort Worth, two of the largest metropolitan areas in the nation and the two largest in the state, the corridor provides primary access for freight movement between these two major markets and with major seaports in the Houston Gulf Coast area.[58]

The North Central Texas Council of Governments (NCTCOG) completed an “I-45 ZEV Corridor Plan,” funded by the Federal Highway Administration, which addresses the need for hydrogen fueling infrastructure on this major trucking route.[59] The project team is collaborating with NCTCOG as well as with commercial fuel cell electric truck manufacturers and fleet operators to identify optimal near-term fueling station locations for commercial fleet applications. To build on this single corridor effort, a broader planning exercise followed by infrastructure and pilot fleet rollout covering the at-scale region of the Texas Triangle and its connections to other regions of the country could provide more significant benefits in terms of scaled-up mobility supply and demand, community health, cost reduction for Texas, and a pilot case for other U.S. regions.

5.2. Pursue Hydrogen Blending for Power Plant Decarbonization

The project team is working with ONEOK, ONE Gas, and CenterPoint to identify natural gas pipelines and end use applications conducive to hydrogen blending. ONEOK focuses primarily on high-pressure transmission line operations, whereas ONE Gas and CenterPoint focus on lower-pressure distribution lines and key end-use applications, including power generation.

Analyses by the project team of the potential for hydrogen blending at natural gas power plants in Texas found that there are 43 plants within 3 miles (5 km) of existing hydrogen pipelines that could be candidates for partial fuel substitution via blending with hydrogen within the premises of the power plant. Further details on this analysis can be found in additional reading materials.

Blending potential and the resulting demand volume depend on the materials that would be in contacts with hydrogen and the location of existing assets. Pursuing this effort by developing a best practices guidance document to understand specific systems and infrastructure connections at two or three power plants should provide insight to scale-up feasibility and implementation at other locations. As the team’s modeling results showed, leveraging the existing hydrogen assets and pipelines along the Gulf Coast would help reduce costs for delivering clean hydrogen to power plants in the near-term while volume demand and market opportunities grow to support a wider rollout across the state.

[58] TxDOT I-45 Freight Corridor Plan, https://ftp.txdot.gov/pub/txdot/move-texas-freight/studies/i45-freight-corridor-plan.pdf
[59] https://www.nctcog.org/getmedia/d9c0e5a8-64a7-4c20-a61d-3dbc735b7c28/IH-45-0-Emissions.pdf

The pipeline operators are also evaluating other end-use applications that could accept blends of hydrogen and natural gas that would have similar benefits in terms of GHG emission reductions. Applications under consideration range from on-site, point-of-use blending for industrial uses to the controlled blending of isolated distribution network segments that can be monitored or instrumented for demonstration and evaluation for broader deployment.

5.3. Implement SMR, POX, or ATR with CCS

The HOwDI model results show promise for SMR with CCS as a means of providing cost-competitive clean hydrogen for transportation and industrial uses. Numerous projects are in various stages of development in Texas for industrial-scale hydrogen production using SMR and ATR technology. Most of the focus is on the Gulf Coast region near existing hydrogen and CO_2 pipelines with existing hydrogen markets for ammonia, methanol, petrochemical, and refining operations. Captured CO_2 from hydrogen production could be transported to a storage or EOR site via an existing CO_2 pipeline owned and operated by Denbury Resources or into an alternative pipeline.

Denbury Resources has an established business of providing CO_2 for EOR operations in Louisiana. There is also interest in CO_2 injection for sequestration in the geological formation along the Texas Gulf Coast. According to the Great Plains Institute, Texas' CO_2 storage potential in saline formations is estimated at nearly 1.4 trillion tonnes with an additional 4.9 billion tonnes in EOR operations, which inherently provide long-term storage upon cessation of oil recovery.[60] Implementation of large CCS projects in Texas will allow for decarbonization of hydrogen for commercial markets. H2@Scale sponsoring participants Chevron and Air Liquide have obtained access to such CO_2 storage along the Texas Gulf Coast to support large-scale clean hydrogen production.

5.4. Implementation of Wind Power to Hydrogen

5.4.1. Offshore Wind Power to Hydrogen

Results from modeling by the project team indicate that renewable electrolysis hydrogen production, when partnered with the clean hydrogen production tax credit, could meet target costs for hydrogen production. The project team examined the potential for offshore wind in the Gulf of Mexico as a power source for hydrogen production. Although not a near-term clean hydrogen production option due to economics, it has substantial long-term potential. Recently, two offshore wind farm projects were announced. One project is located 24 nautical miles off the coast of Galveston, Texas, with a total of about 547,000 acres covering a region larger than the city of Houston and the potential to power 2.3 million homes, per the U.S. Department of Interior's Bureau of Ocean Energy Management. The other project is located near Port Arthur, Texas, about 56 nautical miles off the coast of Lake Charles, Louisiana, covering about 188,000 acres with the potential to power 799,000 homes.[61]

[60] Abramson et al., "Transport Infrastructure for Carbon Capture and Storage," Great Plains Institute, June 2020.
[61] Ferman, "Offshore wind farm proposed for Gulf of Mexico near Galveston could power 2.3 million homes," Texas Tribune, 7-22-2022.

5.4.2. Onshore Wind Power

The project team is working with Mitsubishi Heavy Industries America to analyze the potential for curtailed wind capacity from either transmission congestion on the electric grid or economic curtailment due to low or negative energy prices to be used to power hydrogen electrolyzers as an “alternate off-taker” and energy storage solution. The project team developed models that will help wind farm operators plan for curtailment and optimize the value of their generating assets. Additionally, hydrogen as a solution for grid-scale long-duration energy storage could help support the continued build-out of renewable power generation such as wind and solar.

In January 2022, ERCOT released its “Long Term West Texas Export Study” that included the findings that wind and solar generation capacity could significantly be constrained as early as 2023.[62] By 2030, curtailment levels of wind and solar could reach 28.4%.[63] Further, the report stated that “Technologies beyond typical 345-kV circuit additions are needed to effectively improve the West Texas export limit.” Alternatively stated, building more electric transmission lines cannot alleviate grid constraints caused by too much wind and solar in the wrong locations in the Texas energy system.

Implementation of projects producing hydrogen from electrolysis during renewable curtailment periods, followed by hydrogen storage either in underground salt caverns, hydrogen pipelines, or blending of hydrogen into the natural gas pipeline network could provide a long-duration grid-scale energy storage solution that would relieve congestion on the grid and support the continued build-out of wind and solar power generating capacity.

5.5. Export of Clean Hydrogen

The project team’s analysis indicates that clean hydrogen production in Texas, especially when combined with tax credits, can be competitive and replace traditional hydrogen production. The project team and industry partners with operations in Texas evaluated opportunities to export clean hydrogen from the Gulf Coast ports in Texas, due to growing global demand for clean hydrogen. Both cryogenic hydrogen and hydrogen converted to “green” ammonia and methanol are under consideration. Multiple sites for such a project exist along the Gulf Coast, including Port Arthur, Port Houston, and Port of Corpus Christi. These could become available if project economics prove favorable.

Using potential clean hydrogen production pathways, the project team supported a techno-economic analysis of decarbonized ammonia production, the results of which will be used to analyze opportunities for hydrogen export (via ammonia) from the Gulf Coast region. As the HOwDI model results indicate, the pathways to competitive costs and economics will include leveraging existing hydrogen assets, which are numerous in the Gulf Coast region, as well as supporting research and development to drive down the costs of key hydrogen production and distribution technologies.

[62] https://www.ercot.com/files/docs/2022/01/14/Long-Term-West-Texas-Export-Study-Report.pdf
[63] Ibid, pg.7.

5.6. Pursue At-Scale Biomass Gasification

Results from the HOwDI simulations show a strong correlation between the capital cost of hydrogen production equipment and its feedstock, fuel, and energy source. Although established hydrogen technologies may provide the quickest path to scale-up, the maturity of the technology may offer less potential to reduce capital costs. Thus, it is important to continue to explore emerging technologies and new hydrogen production methods, such as biomass gasification with catalytic water-gas shift.

In late 2021, Houston-based SunGas Renewables announced plans to build the first woody biomass to hydrogen plant in California, and similar projects could be built in Texas.[64] SunGas Renewables has also partnered with Arbor Gas to build a gasification plant near Beaumont, Texas. Although the Beaumont plant will produce liquid fuels, hydrogen is an intermediate product (from the gasifier) and could alternatively be used as an end product, if economically favorable. Combined with CO_2 capture, via an added step to the acid gas removal process following water-gas shift, such clean fuels facilities could have a "net negative" carbon intensity if the life-cycle GHG emissions of the delivered and processed biomass feedstocks, facility energy use, and uncaptured CO_2 were less than the captured and sequestered CO_2.

5.7. Refresh Policy Incentives Framework and Bridge Gaps

For Texas to keep its leadership position in hydrogen production, distribution, and demand markets, its policy framework will play an important role in scaling up new markets and transitioning to new production sources. At the national level, "there is unprecedented policy momentum for clean hydrogen in the United States."[65] As exemplified by the 79 initial responses to the Hydrogen Hubs funding opportunity announcement, there is great competition among regions for the billions of federal dollars allocated to clean hydrogen.

The October 2023 selection of the HyVelocity Gulf Coast Hydrogen Hub to enter into award negotiations under DOE's Regional Clean Hydrogen Hubs initiative shows that Texas is ready to expedite the expansion of generation and deployment of hydrogen throughout the state by leveraging existing infrastructure and by identifying and reducing the opaqueness and complexity of regulatory, planning, and permitting barriers.

In regard to Texas policy, Medlock and Hung developed a framework to evaluate how market interventions can be directed. They found it was important to stimulate investments along the *entire* supply chain to support market growth.[66] Their framework provides several examples of such support commensurate with the policy directive from DOE on social and environmental justice, job creation, and training of a skilled workforce in areas of potential clean hydrogen deployment. These include local measures such as grants and tax abatement on the supply side and government grants, loan guarantees, and other subsidies to end-users on the demand side.

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[64] https://sungasrenewables.com/worlds-first-carbon-removal-plant-converting-wood-waste-to-hydrogen/
[65] https://energyfuturesinitiative.org/reports/the-u-s-hydrogen-demand-action-plan-2/
[66] https://www.bakerinstitute.org/research/developing-robust-hydrogen-market-texas

It is critical for hydrogen stakeholders, such as members of the H2@Scale Texas team and THA, to continue identifying potential barriers to the deployment of hydrogen in transportation, industrial, chemical, energy storage, and grid applications. The THA and industry legislative affairs representatives will need to work with key legislators, legislative committees, and state and local agencies to advance clean hydrogen in Texas and nationally. Actions taken within the most recent Texas legislative session (88th Session – 2023) saw two bills adopted to support hydrogen applications. HB 3100 establishes the Texas Hydrogen Infrastructure and Vehicle Grant Program within the Texas Emissions Reduction Program at the Texas Commission on Environmental Quality.[67] HB 2847 focuses on developing a policy framework regarding the production, transportation, and storage of hydrogen.[68] The resulting framework authorizes the Texas Railroad Commission to establish a Texas Hydrogen Policy Council. The Council will study the development of the hydrogen industry, monitor and coordinate regional applications for clean hydrogen hubs, and make recommendations regarding the Commission's regulatory framework over hydrogen.

There is also an urgent need to develop and disseminate educational materials covering all aspects of hydrogen from production to end-use. Active engagement of community and labor leaders could happen early and often. This includes communication to communities of the environmental benefits of hydrogen and an explanation of the various hydrogen production methods and associated carbon intensities.

6. Conclusions

Due to Texas' abundance of natural resources, existing infrastructure, and institutional knowledge, the state is an attractive location for the expansion and development of a future hydrogen economy. New hydrogen projects can leverage existing hydrogen pipelines and facilities while offsetting existing carbon-intensive demand, particularly in sectors such as heavy-duty transportation, industry, and oil/chemical refining, with clean hydrogen from new production.

The project team developed the HOwDI model to assess the feasibility of delivering cost-competitive clean hydrogen for use in the transportation sector in Texas. The HOwDI model "builds out" a hydrogen production and distribution system that meets a specified user demand while minimizing cost. Due to its system and network framework approach, model results can provide insights on the infrastructure cost elements with the largest impact on the final cost of delivered fuel, identify locations within the state that are best suited for new hydrogen infrastructure, and guide near-term hydrogen project selection in the state.

Model results indicate that there are a multitude of pathways that can achieve hydrogen delivery cost targets of $4/kg or less dispensed at a fueling station. Across all scenarios, reducing fuel dispenser costs was strongly correlated with meeting the delivered hydrogen cost target. Other significant cost drivers

[67] https://capitol.texas.gov/BillLookup/History.aspx?LegSess=88R&Bill=HB3100
[68] https://capitol.texas.gov/BillLookup/History.aspx?LegSess=88R&Bill=HB2847

include the capital costs of hydrogen production equipment (SMR and electrolyzers) and feedstock costs (natural gas and electricity prices).

When considering future hydrogen infrastructure deployment in Texas, the HOwDI model indicated a strong preference for building hydrogen production infrastructure at or near the location of hydrogen demand, thereby reducing the costs of distribution infrastructure. Recently expanded and/or federal tax credits (e.g., IRS sections 45Q and 45V) have the potential to significantly reduce the cost of clean hydrogen and increase the pathway options for meeting targets for cost-competitiveness of delivered hydrogen fuel.

A number of actions and next steps are recommended based on the work described in this report. To lay the groundwork of the topic in question, an essential step is to engage in hydrogen energy outreach to Texas legislators and communities. Without this engagement, policy actions and the build-out of new infrastructure could encounter delays or other hurdles. Alongside an outreach component, clean hydrogen energy infrastructure can deliver benefits to multiple energy and industrial sectors, such as medium- and heavy-duty trucking, energy storage and power generation, and avoidance of renewable energy curtailment. Investments in clean hydrogen, whether SMR with CCS or electrolysis from renewables, could grow statewide from an initial focus on Gulf Coast applications and markets where existing supply, delivery, and storage infrastructure could help reduce near-term delivery costs and existing users could help drive demand.

7. Additional Reading Materials-H2@UT White Papers

[1.] T.A. Deetjen, J.D. Rhodes, R.E. Hebner, M.C. Lewis, F.T. Davidson, and A.C. Lloyd, "Market Competitive Electrolysis in ERCOT," July 2021.

[2.] J.D. Rhodes, T.A. Deetjen, R.E. Hebner, M.C. Lewis, N. Bouwkamp, B. Weeks, F.T. Davidson, and A.C. Lloyd, "Renewable Electrolysis in Texas: Pipelines versus Power Lines," August 2021.

[3.] J.D. Rhodes, T. Deetjen, F.T. Davidson, M.C. Lewis, and R.E. Hebner, "Hydrogen Blending in Texas Natural Gas Power Plants at Scale," January 2022.

[4.] E. Beagle, J. Gawlick, W. Wade, A. Nisman, J.D. Rhodes, M.C. Lewis, M.E. Webber, and R.E. Hebner, "Texas' Role in the Future Global Demand for Hydrogen," September 2023.

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