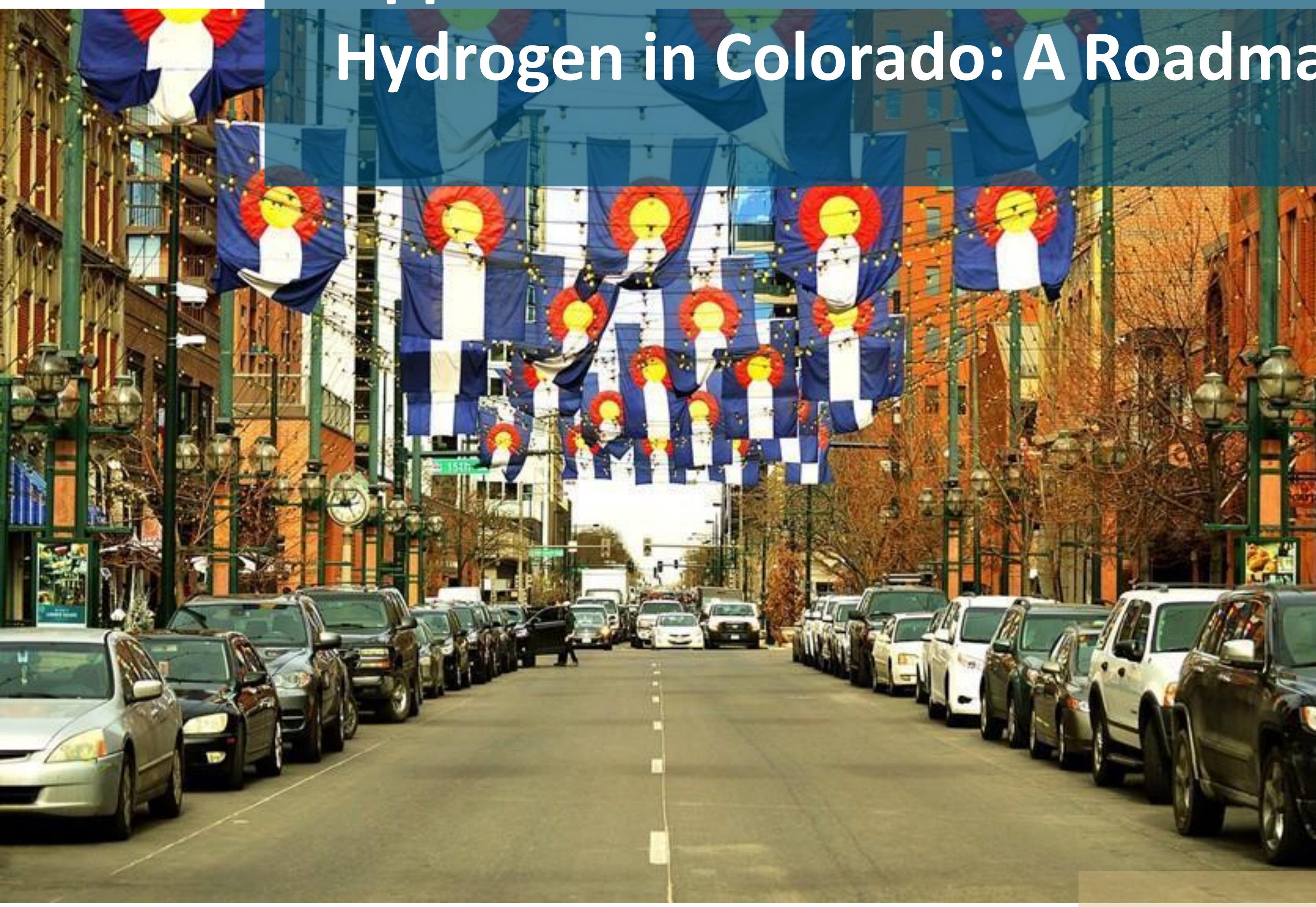
October 2021

Opportunities for Low-Carbon Hydrogen in Colorado: A Roadmap



Energy & Environmental Economics
44 Montgomery St., Suite 1500
San Francisco, CA 94104

Niki Lintmeijer
Mengyao Yuan
Anthony Fratto
John Stevens
Tory Clark
Amber Mahone

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Executive summary

The State of Colorado aims to reduce Greenhouse Gas (GHG) emissions by at least 26% by 2025, 50% by 2030, and 90% by 2050 relative to 2005 emissions levels. To achieve this goal, the Colorado Energy Office (CEO) in January 2021 released the state's *Greenhouse Gas Pollution Roadmap* ("GHG Roadmap"), which outlines an achievable statewide decarbonization pathway. The GHG Roadmap identifies hydrogen as a potentially important low-carbon fuel for beyond 2030, especially to reduce emissions in hard-to-electrify sectors[1].

Characteristics unique to Colorado, such as its regional leadership in decarbonizing the electric sector using abundant wind and solar resources, its existing gas supply chain, and its strong intellectual capital (including its universities and the National Renewable Energy Laboratory (NREL)), could position the state for a role in the development and scale-up of hydrogen in the region. To evaluate the potential role hydrogen could play in achieving Colorado's climate goals, CEO commissioned Energy & Environmental Economics (E3) to develop this Low-Carbon Hydrogen Roadmap. This roadmap identifies opportunities, barriers and recommended actions for the deployment of low-carbon hydrogen in the state of Colorado over the next fifteen years.

Colorado's hydrogen supply chain & end-use opportunities

There are many potential supply chain paths for low-carbon hydrogen production, transport, storage, and delivery and the best paths forward for a hydrogen supply chain are not yet settled in the market. Most hydrogen produced today does not qualify as low carbon since it is produced via Steam Methane Reforming (SMR) of natural gas. Electrolysis using renewable electricity and SMR with Carbon Capture and Storage (CCS) are the most commercially available technologies to produce low-carbon hydrogen. Hydrogen produced from renewables could achieve cost parity with hydrogen from SMR with CCS by the mid-2030s, although the exact timing is sensitive to the electrolyzer cost and the renewable electricity price performance trajectory assumed. Hydrogen delivery via pipeline and a large-scale central hub of storage, potentially making use of Colorado's existing gas storage facilities, are likely to be the most cost-effective opportunities for transport and storage, if hydrogen were to be deployed at scale.

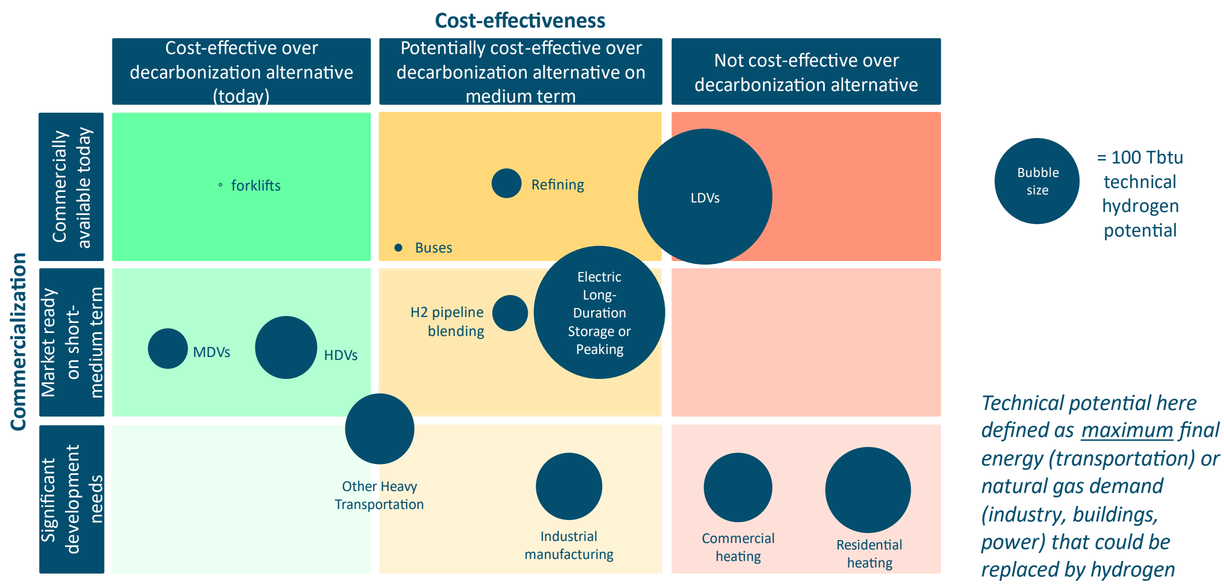
The potential demand for hydrogen exists in a wide range of sectors and end-use applications. In Colorado, E3 expects the most promising short-term applications for hydrogen consumption are in the medium and heavy duty vehicle sector, where some use cases are already cost-effective over decarbonization alternatives such as Battery Electric Vehicles (BEVs), and ready for commercialization pending the increase of a refueling station network and more availability of vehicle makes and models (See Figure 2). Additionally, we expect the application of hydrogen in the electric sector to provide significant potential in the medium term, especially as decarbonization targets become more stringent and the need for long

[1] This report refers to several ways of producing hydrogen as a low-carbon fuel. Low-carbon hydrogen can be produced from renewable electricity using electrolysis, often referred to as "green hydrogen", or produced from natural gas with Carbon Capture and Storage (CCS), often referred to as "blue hydrogen." See Appendix A for a full overview of definitions.

duration, multi-day storage increases. Eventually, hydrogen could replace natural gas[2] use for electric peaking generation, and both hydrogen production through grid-powered electrolysis and hydrogen-fueled electric generation could provide load-following services to the electric grid.

We also expect a potentially promising role to be fulfilled by hydrogen in high-temperature industrial processes, especially as the price of hydrogen becomes competitive with the price of alternative low-carbon fuels. Applications such as the use of hydrogen in Light Duty Vehicles (LDVs) and buildings are not expected to become cost-effective over decarbonization alternatives in the short term, but may provide other benefits to consumers and to the energy system as a whole if a hydrogen market develops at scale. These opportunities are conceptually summarized in Figure , where the size of the bubble represents the approximate energy potential for hydrogen in Colorado between now and 2030.

Figure 1. Conceptual overview of mid-term (2030) hydrogen potential in Colorado



Roadmap recommendations

Through conversations with state agencies in Colorado, a range of hydrogen experts and stakeholders,[3] and E3's research into the current hydrogen market, we recommend that the state of Colorado, as well as its utilities, private sector participants, and other stakeholders pursue the following near-term actions:

1) **Develop a Hydrogen Plan** that includes concrete actions for the deployment of low-carbon hydrogen in Colorado. Drawn from success factors in other regions, as well as from conversations with stakeholders, E3 particularly recommends setting mid-term targets related to:

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[2] This report refers to natural gas as a fossil fuel, consisting of methane and other hydrocarbons that occur underground. In Colorado's Senate Bill 264, this gas is referred to as geological gas.

[3] Throughout the development of the Colorado Low Carbon Hydrogen Roadmap, a Technical Advisory Committee consisting of market players, utility representatives, knowledge institutes and network organizations provided input to the CEO and E3.

a) ***The production of low-carbon hydrogen.*** To inform potential goal setting, E3 analyzed several scenarios for hydrogen deployment in Colorado that show that by 2030, demand for 45,000 metric tons of hydrogen could exist in a "Growth" scenario, versus 85,000 metric tons of hydrogen in a "Transformative" scenario. Assuming production would be supplied by hydrogen from renewable electricity, this demand would require capital investments ranging between $310-$650 million (Growth) and $590-$1,200 million (Transformative), depending on electrolyzer cost trajectories.[4]

b) ***The development of hydrogen infrastructure (i.e. number of refueling stations), potentially concentrated in a few centralized geographic areas or hydrogen hubs.*** E3 estimates that with approximately 4,000 – 20,000 hydrogen-fueled Medium and Heavy Duty Vehicles (MHDV) on the road in 2030 (in the Growth and Transformative scenarios respectively), between 30 (Growth) and 150 (Transformative) refueling stations would be required, with investment costs between $66 million and $330 million.[5]

2) **Investigate the market interest and feasibility of regional early-deployment hydrogen hubs** to demonstrate the use of hydrogen in mature or emerging applications such as heavy-duty transportation. These hubs would combine hydrogen production, storage, and end-use at relatively small scale, drawn from examples in, for instance, Canada and Northern Europe,[6] strategically making use of "anchor tenants" or early adopters existing in the market. The deployment of local hubs would allow the State of Colorado to test the hydrogen supply chain in a centralized setting before the market is fully developed in other regions. A hydrogen hub could be clustered around renewable generation resources and underground storage locations for use in electricity generation, or near heavy-duty transportation hubs. Although the exact location of the hydrogen hubs would need to be determined, E3 recommends investigating the areas in Colorado that combine good wind or solar resources for production with hydrogen transportation and storage opportunities, such as roads and existing pipeline infrastructure, within reasonable proximity of promising end-use opportunities and willing partners, such as the Denver Metropolitan Area, Colorado Springs, or Fort Collins.

3) **Develop pilot projects on the use of hydrogen in the power sector** to test hydrogen applications using existing infrastructure, potentially in combination with a local hydrogen hub. Pilot projects could include the combustion of hydrogen for power generation in gas turbines, in combination with hydrogen storage, potentially making strategic use of retiring coal-fired generation assets. One such example of this is the Intermountain Power Project (IPP) in Utah, which is set to convert its existing coal plant into gas-fired generation units capable of using hydrogen, plus on-site green hydrogen production and storage.[7]

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[4] E3 estimates electrolyzer cost trajectories to decline to around $970/kW in a conservative scenario, and $525/kW in an optimistic scenario by 2030, from around $1,100/kW today.

[5] The Transformative scenario as modeled by E3 also includes the adoption of 50,000 Light-Duty Vehicles (LDVs), for which another +/-30 refueling stations would be required.

[6] See: Hydrogen Strategy for Canada (December 2020) and the European NorthH2 project.

[7] See: https://www.ipautah.com/ipp-renewed/. The facility will use 100% hydrogen by 2045.

4) **Develop pilots related to the blending of hydrogen in existing gas infrastructure**, as part of utility-specific Clean Heat Plans. Senate Bill 21-264, passed by the Colorado state legislature in June 2021, requires Gas Distribution Utilities (GDUs) to file a Clean Heat Plan with the public utilities commission (PUC), demonstrating how the GDU will use clean heat resources to meet the clean heat targets of 4% reduction in greenhouse gases by 2025 and 22% by 2030 compared to 2015 levels.[8] Since green hydrogen is an allowed resource under SB 21-264, E3 recommends GDUs pilot the use of green hydrogen in existing infrastructure to test the application and effectiveness of hydrogen blending.

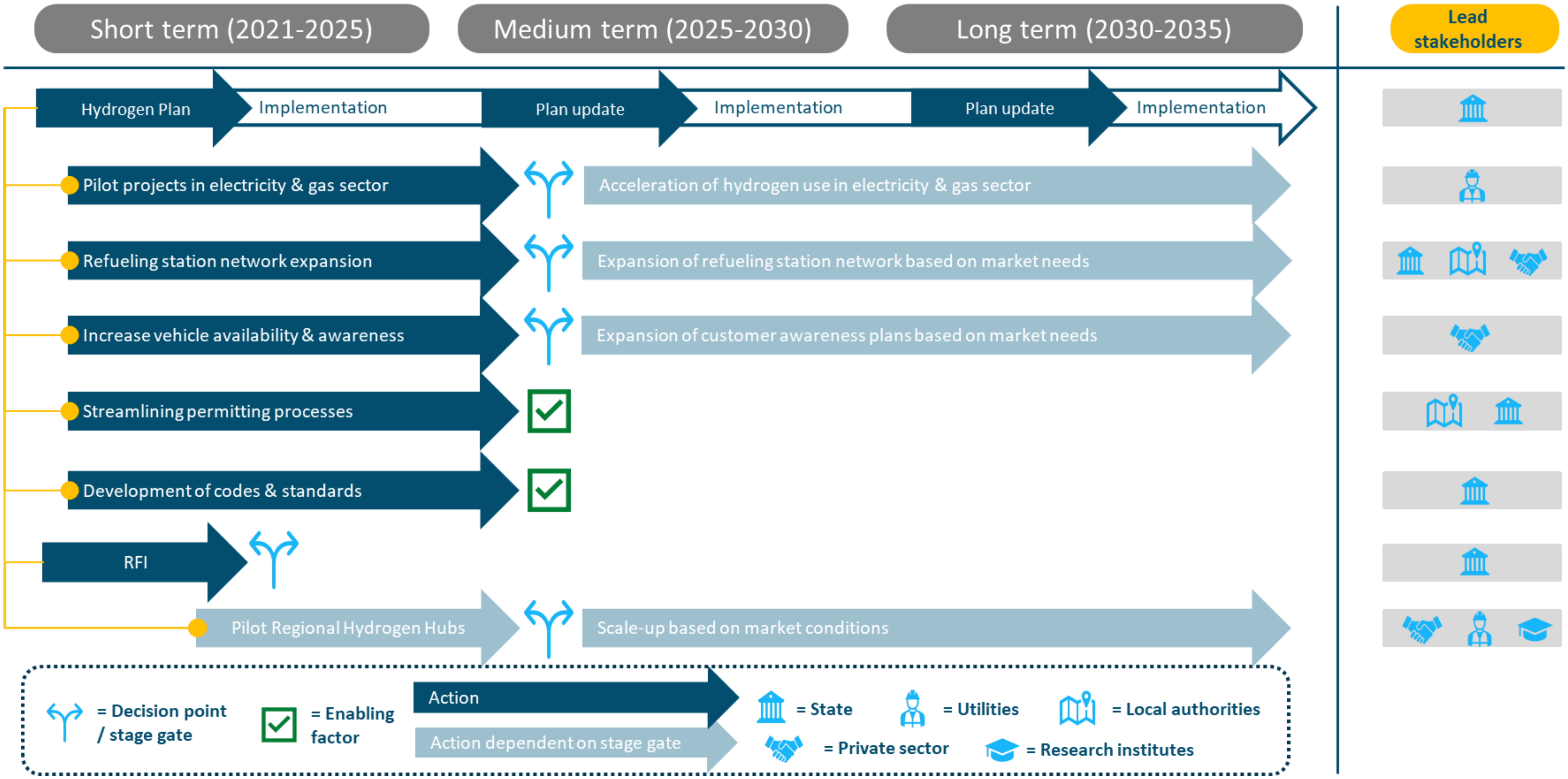
5) A first step towards implementing these recommendations could be to **issue a Request for Information (RFI) to potential Colorado hydrogen market participants** to assess the feasibility of developing pilots and/or geographically-based hydrogen hubs in the state. This RFI will gauge market interest and potential participation for the recommendations provided above, including:
    - Interest from market parties in becoming involved in the development of hydrogen hubs;
    - Information on where potential hydrogen locations could exist;
    - The scale of potential production or demand offered by market parties;
    - The required funding for the development of (components of) a hub and level of co-funding available from private market participants;
    - How market participants propose to re-purpose or leverage existing infrastructure.

Other near to mid-term actions recommended in this report, which would require the participation of non-government parties across Colorado, include:

1. Developing a hydrogen refueling station network, perhaps geographically clustered, following the results of the State's RFI and Hydrogen Plan as described above.
2. In cooperation with (inter)regional authorities, developing codes and standards for hydrogen transport and storage, for instance related to safety metrics, blending percentages, and material requirements (similar to Colorado's Retail Hydrogen Fueling Regulation). As the need for hydrogen codes and standards is shared across regions, interstate and national cooperation on the development of such codes and standards is recommended.
3. Streamlining permitting processes across the state to allow for accelerated construction of infrastructure, which has been noted by stakeholders as a barrier to hydrogen development projects in the state.
4. Increasing hydrogen fuel cell vehicle market availability and customer awareness, supported by transportation Original Equipment Manufacturers (OEMs) and other hydrogen market participants.

[8] The directions in the Clean Heat Plan are technology neutral, allowing for the use of energy efficiency, electrification, recovered methane and green hydrogen to meet a GDU's carbon reduction target.

Figure 2. Roadmap towards accelerated low-carbon hydrogen deployment in Colorado



1. Why Low-Carbon Hydrogen in Colorado?

1.1. Introduction

The State of Colorado has set ambitious, science-based climate targets. Under the leadership of Governor Jared Polis, Colorado has stated a vision to achieve a 100% renewable energy future by 2040.[9] House Bill 19-1261, signed by Governor Polis in 2019, compels Colorado to reduce its greenhouse gas (GHG) pollution by at least 26% by 2025, 50% by 2030, and 90% by 2050, relative to 2005 levels.[10] Achieving these goals will require transformative changes in every sector of the economy.

In January 2021, Colorado released its *Greenhouse Gas Pollution Reduction Roadmap* ("GHG Roadmap"), outlining an achievable pathway to meet the state's climate goals. The GHG Roadmap shows how Colorado's largest sources of GHG emissions, the transportation sector, industrial applications, electricity generation and fuel use in buildings, can drastically reduce emissions using existing technologies. The GHG Roadmap finds that additional policies beyond those already taken by the state are necessary, and that an emphasis on low-carbon fuels is important beyond 2030. In particular, the GHG Roadmap notes that low-carbon fuels may be important after 2030, but that the role of ethanol, biodiesel, renewable natural gas, advanced biofuels and hydrogen will need to start ramping up between 2025 and 2030.[11]

Hydrogen is a potentially valuable resource to decarbonize hard-to-electrify sectors such as industrial applications and heavy transportation. It can also provide firm zero-carbon capacity to the electric grid. Although research into hydrogen as a potential energy carrier is not new, the last two years have seen a global influx of regional roadmaps for the deployment of hydrogen as costs of renewables and hydrogen production have declined. For example, both the European Union and Canada published their vision of a hydrogen economy in 2020, following similar ambitions from Australia (2018), Japan (2018) and New Zealand (2019). In the U.S., recent reports have demonstrated how the American economy could significantly ramp up demand for hydrogen in energy-intensive end-use applications in the next decades.[12] Characteristics unique to Colorado, such as its wind and solar resources, existing gas supply chain, and presence of research bodies, may position the state for a role in the development and scale-up of hydrogen in the region.

Given Colorado's ambitious climate goals and the potential role the state can play in a hydrogen supply chain, the Colorado Energy Office (CEO) in 2021 commissioned a Low-Carbon Hydrogen Roadmap. This Roadmap, developed by Energy & Environmental Economics (E3), examines the role of hydrogen in the State of Colorado and identifies opportunities and barriers to building a hydrogen supply chain. In particular, the Roadmap defines the state of the hydrogen market and the opportunities for both

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[9] See: https://www.colorado.gov/governor/news/governor-polis-releases-roadmap-100-percent-renewable-energy-and-bold-climate-action

[10] See: https://leg.colorado.gov/bills/hb19-1261

[11] See: GHG Roadmap, page 55.

[12] For instance, two U.S.-wide reports on the potential for hydrogen in the American economy were published in 2020, authored by the Department of Energy (DOE) and the Fuel Cell & Hydrogen Association.

production and end-use applications of hydrogen in Colorado, potential barriers to the deployment of a hydrogen economy and the steps Colorado could take to overcome those barriers in the next 15 year period.

1.2. What is low-carbon hydrogen?

Hydrogen (H_2) is the lightest and most simple element on our planet. Hydrogen has the highest energy per mass of any fuel: for example, it carries three times the energy content of an equivalent weight of gasoline. While being a potentially valuable energy carrier, hydrogen also has the lowest energy content by volume of any fuel, resulting in technical challenges related to storage and distribution. In addition, although hydrogen releases no GHG emissions when combusted to produce electricity or heat, hydrogen requires relatively high volumes to achieve similar levels of emission reductions compared to other low-carbon gases.

Hydrogen can be produced in a variety of ways. At present, the majority of global hydrogen production is derived from fossil fuels without the capture and storage of released CO_2 emissions, and therefore is not carbon free. Although standardized and consistent definitions of low-carbon hydrogen have not yet been established, this Roadmap refers to low-carbon hydrogen as hydrogen produced with significantly reduced life-cycle GHG emissions compared to existing hydrogen production. This encompasses both the production of fossil-based hydrogen with Carbon Capture and Storage (CCS), often referred to as “blue hydrogen” and hydrogen produced from renewable electricity, often referred to as “green hydrogen.” A complete overview of hydrogen production methodologies and definitions is included in Appendix A: Definitions of Low-Carbon Hydrogen.

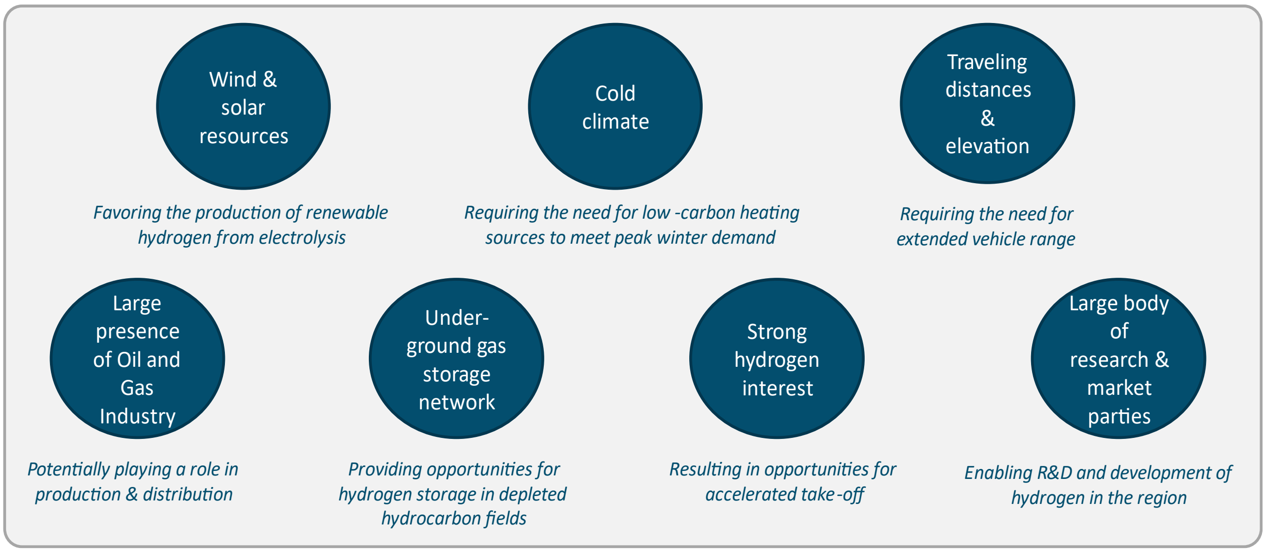
1.3. Colorado’s hydrogen advantages

Colorado possesses several advantages in deploying low-carbon hydrogen as a source of energy relative to other locations in the United States. As Colorado has abundant wind and solar resources, significant opportunities for the cost-effective production of low-carbon hydrogen exist in Colorado, especially because the costs of hydrogen from renewable electricity are expected to decline in the future. Additionally, when deployed at scale, the lowest cost way to transmit and store hydrogen could utilize some of the gas pipeline and geologic storage systems that already exist in the state. Colorado’s population centers are close to many existing geologic formations that could potentially be used to store hydrogen at low cost, and the state has an extensive gas pipeline network from the existing oil & gas industry. The presence of this industry also indicates that Colorado could potentially take advantage of its current infrastructure to produce low-carbon hydrogen from fossil-based sources with the addition of CCS, if needed to kick-off the deployment of low-carbon hydrogen in early stages.

In addition to the potential advantages across the hydrogen production supply chain, Colorado also has several characteristics that may favor the use of hydrogen in end-use applications. For instance, the state’s cold climate may make the use of low-carbon fuels, such as hydrogen, complementary to the use of electric heat pumps to supply heat during cold winter periods. Moreover, Colorado’s travel distances and high elevation features may make hydrogen fuel cell transportation applications more attractive than parts of the country with milder climates, lower elevations, and denser urban areas.

Finally, a network of players active in the hydrogen economy already exists in Colorado. With its large presence of research bodies, network organizations, technology providers and industrial players, an overview of which is provided in Section 3.4, Colorado seems well suited for the development and scale-up of hydrogen in the region. An overview of potential hydrogen advantages specific to Colorado is provided in Figure 1.

Figure 1. Region-specific factors which create potential opportunities for hydrogen in Colorado



1.4. About the Colorado Low-Carbon Hydrogen Roadmap

This Roadmap provides an overview of opportunities for the State of Colorado to facilitate a hydrogen economy. The Roadmap explores the current state of the global hydrogen market and translates opportunities for hydrogen production, transportation, electric generation and end-use consumption to Colorado's existing and potential future supply chain. In addition, the Roadmap identifies current barriers to the deployment of hydrogen and the key success factors to overcome these barriers on a medium-term timescale.

Opportunities for the use of hydrogen in end-use applications are examined using Colorado's existing GHG Roadmap and compared to the HB-1261 scenario that was developed in the GHG Roadmap as example pathways for Colorado to achieve GHG reductions of 90% by 2050. The Low-Carbon Hydrogen Roadmap examines the cost-effectiveness of using hydrogen in end-use applications compared to alternative decarbonization strategies such as electrification or the use of decarbonized gases. As such, this Roadmap presents an overview of the most promising applications for hydrogen and provides recommended actions for the state and other relevant stakeholders to deploy hydrogen in these sectors.

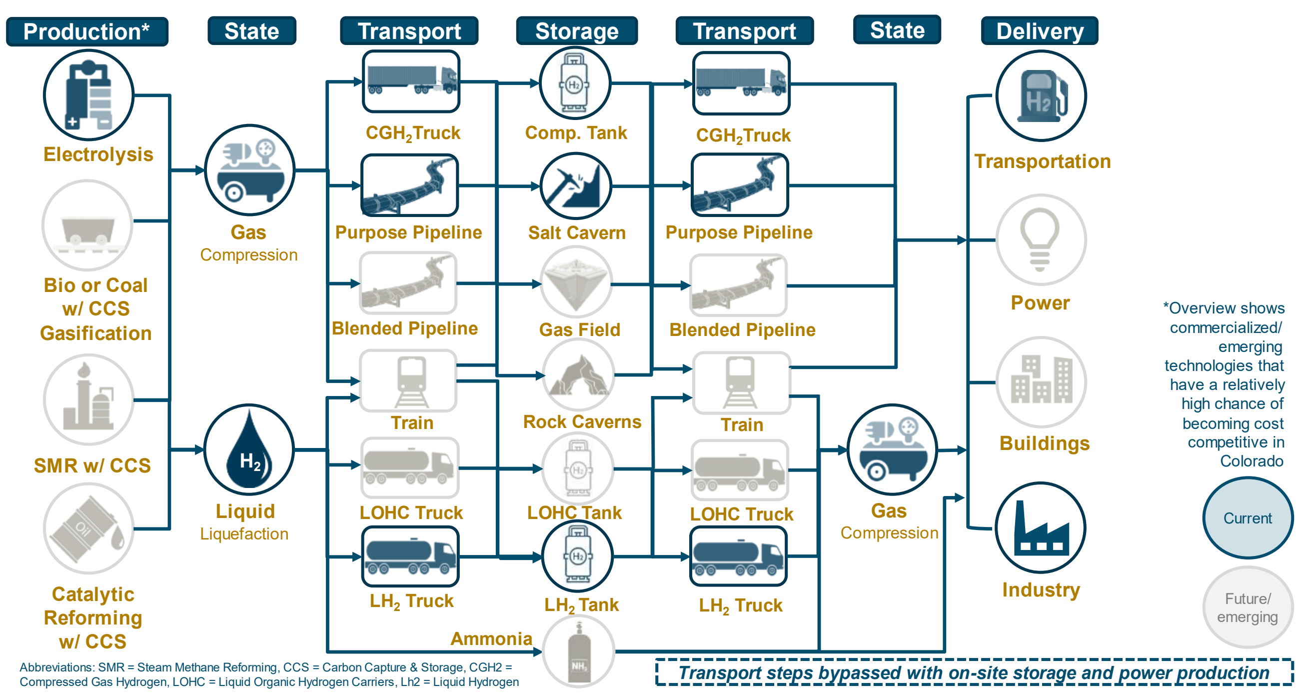
2. The State of the Low-Carbon Hydrogen Market

This chapter provides an overview of the current state of the low-carbon hydrogen market. The goal of this overview is to translate market developments and trends observed across the U.S. and abroad to the context of Colorado. In addition, this chapter provides background on the hydrogen supply chain including its methods of production, transportation and storage, to be able to identify the available options for the deployment of hydrogen in the short to medium term, as well as to identify potential barriers to building a hydrogen economy in the state.

2.1. The hydrogen supply chain

The schematic below provides an overview of the low-carbon hydrogen supply chain. The figure distinguishes between current supply chain options (in blue) and potential future supply chain options (in green). Potential future supply chain options are defined as commercialized or emerging technologies that have a relatively high chance of becoming cost competitive in Colorado. As the figure illustrates, there are many potential supply chain paths for hydrogen production, transport, storage, and delivery. The most promising near-term options circumvent the need for a complete hydrogen delivery supply chain, and would instead use utility on-site production of hydrogen, coupled with on-site storage and use, for example, through combustion in electric generation turbines or as feedstock in industrial processes. For a robust, large-scale hydrogen industry to develop, a more interconnected hydrogen supply chain will need to take shape. However, the best path forward for production, storage and delivery is not yet settled in the market.

Figure 2. Schematic overview of the low-carbon hydrogen supply chain



2.1.1. Hydrogen production

As hydrogen is highly reactive, it does not typically occur in its elemental state on Earth. Hydrogen can be produced using a number of different processes, including extraction from water or extraction from hydrocarbons. The methods described below all involve inputting chemical, electrical and/or thermal energy in order to create hydrogen and other byproducts. These byproducts typically consist of oxides of carbon or oxygen.

Extraction from water:

- **Low Temperature Electrolysis**: This method involves breaking liquid water into hydrogen and oxygen using an electrical current. Electricity is most commonly provided from renewables or grid electricity.
- **High Temperature Electrolysis**: With high temperature electrolysis, water is heated to high temperature steam, which lowers the amount of electricity that must be used for the electrolytic decomposition of water into hydrogen and oxygen. High-temperature nuclear reactors and waste heat from industrial processes have the best ability to provide the necessary zero-carbon heat.
- **Gasification**: Gasification refers to reacting water with a feedstock of coal or biomass at high pressure and temperature to produce hydrogen, carbon monoxide, and carbon dioxide.

Extraction from hydrocarbons:[13]

- **Steam methane reforming (SMR)**: A process that chemically reforms methane with steam, heat, and pressure to produce hydrogen and carbon dioxide. The reaction is endothermic and requires external heat. Steam methane reforming is currently the highest volume hydrogen production pathway globally.
- **Catalytic reforming**: Chemically reforming petroleum products (hydrocarbons) with a catalyst, heat, and pressure, with hydrogen and carbon dioxide being produced in the process. The hydrogen produced is often consumed in other processes within a refinery.
- **Partial oxidation (POX)**: An exothermic reaction (does not require external heat) and non-catalytic process in which the hydrocarbon is gasified in the presence of oxygen. Hydrogen and carbon dioxide are produced.
- **Autothermal reforming (ATR)**: A combination of SMR and POX. This process is similar to partial oxidation, except steam is added during the process. Unlike SMR, autothermal reforming does not require external heat. Hydrogen and carbon dioxide are produced.

Currently, low-temperature electrolysis,[14] steam methane reforming (SMR), catalytic reforming and gasification are the most common technologies for the production of hydrogen. Not all of these

[13] If using fossil-based hydrocarbons, the waste carbon dioxide would need to be permanently stored or sequestered in order to be considered a low-carbon hydrogen pathway (as described in the "definitions" section).

[14] Both low-temperature alkaline electrolysis (AEC) and low-temperature polymer electrolyte membrane electrolysis (PEM) are available technologies; although AEC is more commonly used.

technologies provide low-carbon hydrogen: In the United States, almost all hydrogen is produced as "grey hydrogen", referred to as hydrogen produced using fossil fuels, without capture of CO_2. The production of grey hydrogen mostly takes place at oil refineries, via SMR and catalytic refining, or via SMR for ammonia (fertilizer) production. Low-carbon hydrogen would need to be produced by electrolysis (from renewable electricity), or by reforming or gasification in combination with Carbon Capture and Storage (CCS). Although CCS has not been deployed at scale, CCS technology is relatively mature and a number of projects that combine hydrogen production with CCS are in the development phase globally.[15] Although more experimental technologies with low Technology Readiness Levels[16] exist, this Roadmap mostly focuses on the production technologies that are commercially available or emerging.

It is important to note that in addition to the production methods of hydrogen, a distinction can be made between different types of hydrogen in end-use applications. These range from the use of hydrogen in pure form (H_2) to the use of H_2 to produce synthetic fuels, such as Synthetic Natural Gas (CH_4), produced by a combination of hydrogen and a climate-neutral source of CO_2. Although this roadmap primarily focuses on hydrogen in pure form, it references to the use of synthetic fuels as opportunities for hydrogen end-use, for instance in the building sector (outlined in section 3.2.3).

2.1.2. Hydrogen transportation

There are two common methods of transporting hydrogen:

+ **Via trucks (in gas or liquid form).** Trucking of compressed gas hydrogen (CGH_2) or liquid hydrogen (LH_2) are the best methods to transport H_2 today for short- and long-distance delivery, respectively.
+ **Through pipelines (as a gas, either blended or "purpose built").** In the near-term, blending small volumes of hydrogen into existing gas pipelines is possible. However, blending percentages are limited. In the U.S., the estimated technical potential for hydrogen blending is approximately 20% by volume, or 7% by energy, resulting in relatively low carbon savings. This is due to constraints on pipeline materials and gas compressors, as well as gas end-use equipment.[17] Purpose-built pipelines are the most cost-effective way to transport hydrogen in high demand (tens of thousands kg/day). Purpose-built hydrogen pipelines are estimated to be roughly 10-20% more expensive than new natural gas pipelines.[18] They can be found in the U.S. today across Texas and

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[15] See IEA Hydrogen Project Database: https://www.iea.org/reports/hydrogen-projects-database

[16] The US DOE defines Technology Readiness Level as, "A metric used for describing technology maturity. It is a measure used by many U.S. government agencies to assess maturity of evolving technologies (materials, components, devices, etc.) prior to incorporating that technology into a system or subsystem." See: https://www.directives.doe.gov/directives-documents/400-series/0413.3-EGuide-04-admchg1

[17] See: https://www.nrel.gov/docs/fy13osti/51995.pdf

[18] The DOE/H2A model assumes a 10% cost adder to natural gas pipelines to account for inspections, better seals and more control values to accommodate hydrogen. An additional 10% cost adder could be required to account for larger diameter pipelines for hydrogen relative to natural gas pipelines. As noted in the European Hydrogen Backbone Report (2020), costs of a newly built dedicated hydrogen pipeline could be 10-50% more expensive than its natural gas counterpart, with large diameter pipelines (36 inch or more) on the lower end of the estimate.

Louisiana for the expressed purpose of transporting grey hydrogen to refineries and chemical plants. Purpose built hydrogen lines also exist in Europe, but again in a limited industrial corridor.

As shown below in Table 1, when operating at scale, trucking hydrogen is two orders of magnitude more expensive than delivering it via pipeline, but the upfront cost of the pipeline must be amortized by a large amount of hydrogen throughput for this to be true. Retrofitting existing gas pipelines to transport hydrogen is potentially feasible, but determining retrofit costs and compressor/pipeline material compatibility requires a detailed study that is beyond the scope of this work.

Table 1. Illustrative Levelized Costs of Gaseous Tanker Truck and Pipeline Transportation of Hydrogen (Equipment only, does not include fuel cost)

Hydrogen Transportation Method	Approximate Levelized Cost per kg of Hydrogen (2020$/kg)
Gaseous Hydrogen Tanker Truck	$2.17/kg[19]
Dedicated Hydrogen Pipeline	$0.16/kg[20]

In addition, shipping by train in storage tanks (in gas or liquid form) is physically possible and there are viable routes in the U.S., but no planned projects or estimates on costs are available. On a global scale, hydrogen is likely to be transported by ships if an international hydrogen market were to emerge. A mature industry would likely resemble the LNG shipping industry, with liquefied hydrogen or liquid hydrogen-containing chemicals employed to transport the hydrogen across long distances, using specially designed facilities at ports. Naturally, producing hydrogen at scale in close proximity to where it will be used can help reduce or eliminate transportation costs.

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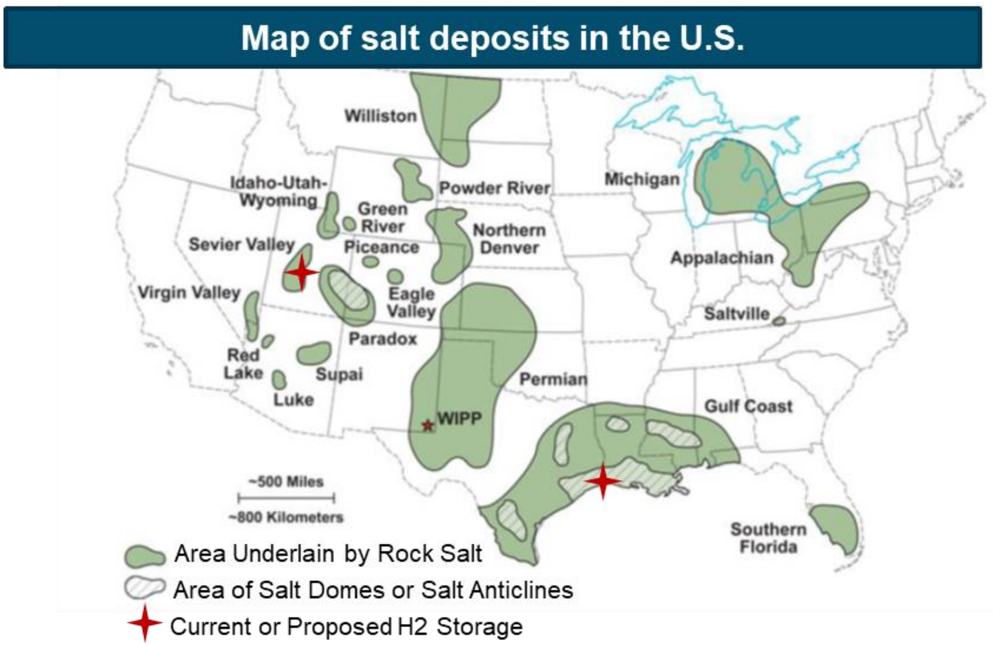
[19] Costs correspond to “Mature” Future High Volume Gaseous Tube Trailer, https://atb.nrel.gov/transportation/2020/index.html?t=eh

[20] Dedicated hydrogen pipeline costs derived from pipeline cost model in Argonne’s HDSAM Model, https://hdsam.es.anl.gov/index.php?content=hdsam and internal E3 analysis. E3 assumes 100 mi pipeline with 25% annual capacity factor, with approximately 175,000 MMBTU/day (1.2 million kg H_2/day) peak send out capacity

2.1.3. Hydrogen storage

Hydrogen can be stored to meet gas consumption demands at any time, which makes it an attractive low-carbon energy option. Hydrogen contains some of the highest amounts of energy per unit mass of any fuel but has a very low energy per unit volume, which makes hydrogen storage costs more expensive than natural gas storage costs. Furthermore, hydrogen's extremely low boiling temperature renders long-term liquid hydrogen storage impractical and means that liquefaction is very expensive. Salt caverns are, to date, the best form of large-scale, long-term storage of gaseous hydrogen because of their ability to store pure hydrogen with low losses and at a relatively low price. Additionally, salt dome storage of hydrogen has been demonstrated commercially. Although the geological availability of salt domes is limited, there are several options across North America and in Colorado specifically, as shown on Figure 3.

Figure 3. Map of salt deposits in the U.S.



For small volumes, short-term storage in pressurized containers is most economically viable. In the long run, if a hydrogen economy were to emerge, a supply chain with a large-scale central hub of storage that can be piped to different areas is likely to be more cost effective than on-site production and storage.

Illustrative costs of storage in salt domes as well as storage in pressurized tanks are provided below in Table 2. Similar to hydrogen transportation costs, this table shows that smaller scale hydrogen storage methods (pressurized tanks) are an order of magnitude more expensive than large scale hydrogen storage methods (geologic storage).

Table 2. Approximate Levelized Cost of Gaseous Hydrogen Storage (Equipment cost plus energy cost of pressurization, does not include fuel cost)

Gaseous Hydrogen Storage Method	Approximate Levelized Cost per kg of Hydrogen (2020$/kg)
Pressurized Tank	$2.25/kg[21]
Salt Dome	$0.25/kg[22]

2.2. Hydrogen production and consumption trends

2.2.1. Hydrogen production today

Global production of low-carbon hydrogen is currently small. In 2020, according to the International Energy Agency, around 4% of global hydrogen supply was produced via low-carbon sources (predominantly electrolysis).[23] However, planned projects indicate that low-carbon hydrogen supply is expected to significantly ramp up in the next decade, as shown on Figure 4. Europe and Australia lead the way in planned projects, driven by several large-scale electrolysis and SMR with CCS projects expecting to come online from 2027 (among which the Asian Renewable Energy Hub in Australia and the H21 North of England project in the United Kingdom). However, the low-carbon hydrogen production capacity available by 2030 is still projected to be small compared to current hydrogen demand.[24]

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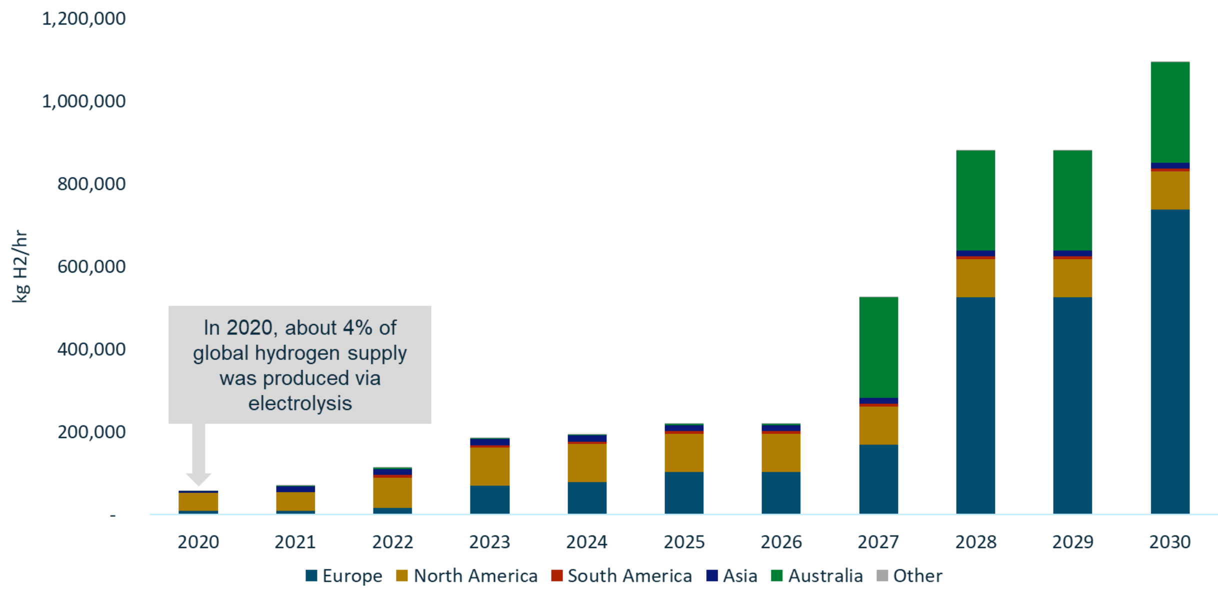
[21] Assume "Underground Pipe Storage" from Slide 16 of https://www.hydrogen.energy.gov/pdfs/review19/st001_ahluwalia_2019_o.pdf

[22] Assume "Salt Cavern Storage" from Slide 19 of https://www.hydrogen.energy.gov/pdfs/review19/st001_ahluwalia_2019_o.pdf

[23] International Energy Agency. Hydrogen Projects Database. 2020. https://www.iea.org/reports/hydrogen-projects-database (Extra data analysis by E3 used to arrive at percent of global hydrogen demand to be satisfied by clean sources)

[24] Idem.

Figure 4. Planned Low-Carbon Hydrogen Capacity by region (2020-2030)



In North America, almost all hydrogen is produced adjacent to, or onsite at, petroleum refineries and ammonia plants using SMRs or catalytic reforming (without CCS). There are however plans to scale up blue and green hydrogen production. For example, the Lake Charles Methanol plant in Louisiana is a planned $5 billion project that will use SMR + CCS to create blue hydrogen that will be consumed at an adjacent methanol plant. Construction is expected to begin in 2021.[25] Plug Power plans to install 120 MW of PEM electrolyzers to create green hydrogen in the New York Science, Technology and Advanced Manufacturing Park in Alabama, NY. This plant will contract hydroelectricity from the Niagara Power Project for its feedstock, though the plant will be drawing from the broader NYISO grid.[26] Finally, Magnum Power plans to develop solar-powered electrolyzers in conjunction with salt dome hydrogen storage at their Delta, UT site adjacent to the Intermountain Power Plant. The Intermountain Power Plant (re-powered from coal generation to gas turbines) would begin burning a 30% hydrogen, 70% natural gas mix in 2025 and by 2045 would burn 100% hydrogen as part of the Los Angeles Department of Water and Power's decarbonization strategy.[27, 28]

2.2.2. Hydrogen consumption today

According to the International Energy Agency (IEA), the current demand for pure hydrogen worldwide is around 70 million metric tons (MMT) per year. The majority of this demand is concentrated in the refining industry (38 MMT) and for ammonia production (31 MMT) and is almost exclusively supplied by fossil

[25] See: https://www.lakecharlesmethanol.com/

[26] See: https://www.ir.plugpower.com/Press-Releases/Press-Release-Details/2021/Plug-Power-to-Build-North-Americas-Largest-Green-Hydrogen-Production-Facility-in-Western-New-York/default.aspx

[27] See: https://millardccp.com/featured-local-news/54-featured-news/5059-magnum-seeks-ok-for-new-hydrogen-project

[28] See: https://power.mhi.com/regions/amer/news/200310.html

sources (grey or brown hydrogen). Only a small amount of hydrogen is consumed in the transportation and power sector. In North America, the vast majority of hydrogen is consumed in a few localized areas:

+ **Petroleum refining**: California (specifically Los Angeles and the Bay Area) dominates hydrogen demand in the Western U.S. due to its large refining capacity and high specific demand for hydrogen per gallon of California-formula gasoline.[29,30] In Colorado, Suncor Energy produces hydrogen at an estimated capacity of 19,000 metric tons per year.[31]
+ **Ammonia production:** Most ammonia production in the U.S. occurs along the Gulf Coast; in the Western U.S., small amounts of ammonia are produced in Wyoming and Oregon.
+ **Power production:** Currently, the most common power production application for hydrogen is using natural gas reformed on-site into H_2 for use in stationary solid oxide fuel cells (SOFC). These SOFCs are used to provide baseload uninterruptible power in locations like data centers where power outages would be extremely expensive.
+ **Transportation:** Hydrogen fuel cell electric vehicles (HFCEV) represent a nascent niche market in the U.S., concentrated in California today. Today's hydrogen pump price is about $10-$15/kg and is not competitive with electric fueling costs for light-duty electric vehicles (EVs).

2.2.3. Potential for future hydrogen consumption in end-use applications

The potential demand for low-carbon hydrogen, in a decarbonized future, exists in a wide range of sectors and end-use applications. In each of these sectors, hydrogen could provide a low-carbon source of energy that must "compete" against alternative decarbonization options to become viable:

+ **Power sector:** Hydrogen could play an important role in the power sector to provide multi-day and seasonal storage, firm capacity and load-following energy. Today, these roles are largely fulfilled by power plants using natural gas. Future demand for hydrogen in the power sector will be driven by increasingly stringent climate policies, the need for low- or zero-carbon firm resources following higher shares of variable renewables, and technology cost-competitiveness. Hydrogen use in the power sector is likely to compete for market share with other emerging long-duration energy storage technologies, such as aqueous batteries. It is not yet clear which technology solutions will prove to be the most scalable and cost-competitive.
+ **Transportation:** In the transportation sector, the application of hydrogen mostly "competes" with battery electric vehicles (BEV), both for light-duty (LDV) and medium/heavy-duty vehicles (MHDV). In terms of logistics and economics, heavy-duty trucking offers a likely opportunity for hydrogen fuel cell vehicles. Still, a low hydrogen fuel price alone is not enough to make renewable hydrogen competitive with BEVs, even for heavy-duty freight. Given the significant station costs, the primary challenge for hydrogen in heavy-duty freight is building the necessary refueling infrastructure and lowering the costs of those stations. Finally, there is interest in using hydrogen

[29] https://h2tools.org/file/9018/download?token=6HwLuhi1

[30] https://doi.org/10.1016/j.fuel.2015.03.038

[31] Hydrogen Analysis Resource Center: Captive, On-Purpose, Hydrogen Production Capacity at U.S. Refineries

to displace jet fuel in commercial airliners, but this application is in early development stages due to the low volumetric energy density of hydrogen.

- **Buildings:** In colder climates, building energy demands are dominated by seasonal space heating loads, with peak heating demands coinciding with cold-snaps. To meet these peak space heating demands, there is a plausible role for hydrogen combustion in furnaces, complementary to electrification in buildings. However, electrification still provides a more economic and efficient alternative for most of the year. To eliminate the use of natural gas in buildings and replace it with 100% hydrogen, entire segments of the gas system and end-use burner tips would need to be converted to be compatible with hydrogen. Alternatively, hydrogen could be transformed into synthetic methane for blending into existing pipelines (by combining hydrogen with a carbon-neutral source of CO_2). This option avoids the blend-wall limitations of hydrogen, or the need to convert pipelines and end uses to support 100% hydrogen. The use of dedicated pipelines that would fully supply building demands by hydrogen has not been demonstrated in the buildings sector worldwide. However, the H21 North of England project in the United Kingdom is investigating and developing such a system.[32]
- **Industry:** Low-carbon hydrogen provides a significant opportunity in the industrial sector to replace current grey or brown hydrogen or to displace natural gas or coal/coke in certain processes. This opportunity is especially large for existing applications such as ammonia production, which already uses hydrogen, or for higher temperature processes with limited alternative decarbonization opportunities. For example, in high temperature (>1600 °F) or thermochemical processes, hydrogen could replace cokes or natural gas. In the industrial sector, hydrogen would mostly need to compete with natural gas with CCS or, in some cases, electrification (such as electric arc furnaces in the steel or foundry industry). Pilots demonstrating the ability to use hydrogen in place of coal for steel refining are planned in Europe.[33]

2.3. Hydrogen policies & goals by region

In the past few years, jurisdictions both outside and within North America have started to establish hydrogen goals or targets related to parts of the hydrogen supply chain (Table 3). For example, the European Union announced a goal to establish up to 40 GW electrolyzer capacity by 2030, Canada plans to supply over 20 million metric tonnes of hydrogen per year by 2050, and Japan calls for 800,000 Fuel Cell Electric Vehicles (FCEV) by 2030. In the U.S., these targets are limited to California, where the state has set goals for fuel cell vehicles and hydrogen refueling stations, although several U.S. states do provide incentives for hydrogen deployment.

[32] See: https://h21.green/projects/h21-north-of-england/

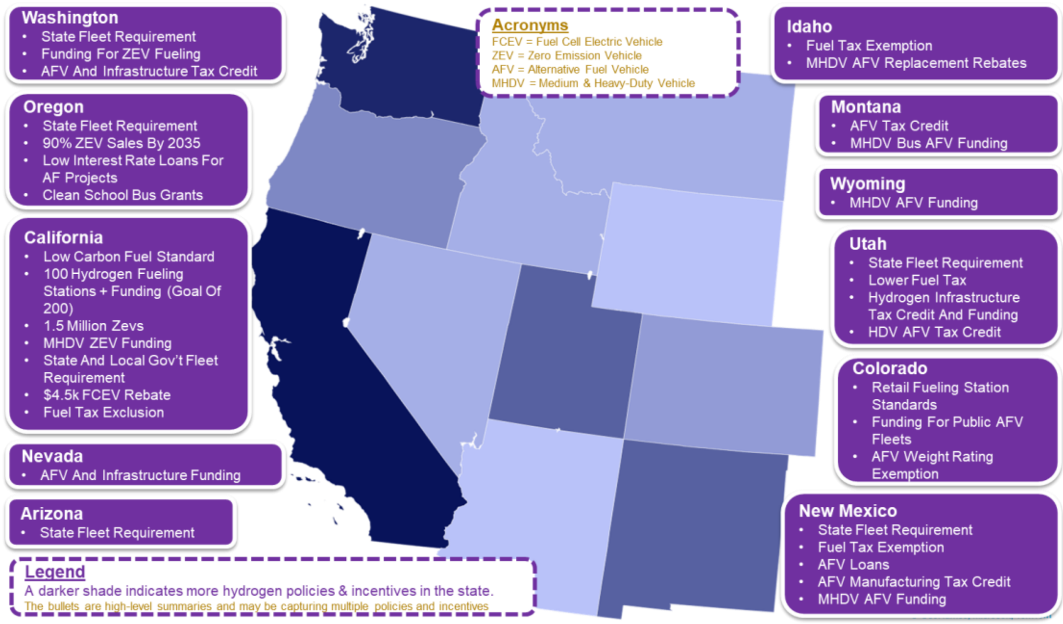
[33] Financial Times. European groups pump money into Swedish “green steel’ start-up. 2021. https://www.ft.com/content/ee91775f-0310-4e1b-b162-ffdf6e066757

Table 3. Examples of hydrogen targets across the world (non-exhaustive)

Category	Region	Goal/target
Production	Europe	6 GW electrolysis by 2024, 40 GW 2030
	Canada	Domestic supply of >20 million tonnes/year in 2050
	South Korea	1.9 million tonnes/year production by 2030
Transportation	Japan	800,000 fuel cell electric vehicles (FCEVs), 1,200 buses and 10,000 forklifts by 2030
	Canada	5 million FCEV by 2050
	South Korea	6.2 million FCEV (of which 2.9 million domestic), 40,000 buses, 30,000 trucks and 1,200 refueling stations by 2040.
	Spain	5,000 light- and heavy-duty vehicles and 150 buses by 2030
	France	50,000 FCEV by 2028
	California	100 hydrogen refueling stations with executive order of 200 stations by 2025
	California	100% sales of Zero Emission Vehicles (ZEV) by 2035 (number of FCEV unspecified).
Other	Japan	Reducing the costs of hydrogen production to 3.2 $/kg by 2030
	Europe	Developing a core European Hydrogen Backbone consisting of over 14,000 miles of pipeline

In addition, hydrogen has begun to play an integral part of broader transportation decarbonization targets and efforts. As seen in Figure 5, most existing hydrogen policies and incentives in the western U.S. focus on Zero Electric Vehicle (ZEV) deployment and funding for both state fleets and public consumers. Fuel tax exemptions are common as well, as are grants for clean school bus fleets.

Figure 5. High level policies, incentives, and standards for hydrogen in the West



California remains the only state actively pushing policies that encourage the adoption of Fuel Cell Electric Vehicles (FCEVs) by specifically targeting the growth of their hydrogen refueling network. Policies include:

+ **AB8** (California Health and Safety Code §43018.9), for which the California Energy Commission (CEC) allocates $20M year to fund at least 100 stations by 2024.[34]
+ **The Low Carbon Fuel Standard (LCFS)** (California Code of Regulations, §95480-95490) which includes the standard LCFS credit for hydrogen as well as an additional **hydrogen refueling infrastructure (HRI) credit**.[35] The HRI allows eligible hydrogen station operators the ability to generate LCFS credits based on the difference between the station's installed capacity and actual hydrogen throughput.[36]

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[34] Stations must have at least 33% of their hydrogen sourced from renewables.

[35] The LCFS establishes an annual declining carbon intensity (CI) target for the transportation fuel pool. It is a credit-based trading system so regulated entities generate "deficits" for their fuels above the CI target and must purchase credits generated by low-carbon fuel producers (1 LCFS credit = 1 $mtCO_{2e}$). There is an informal market cap of $200/credit. The current avg price (April 2021) is $190/credit. Therefore, a hydrogen refueling station can get LCFS credits based on the throughput of hydrogen sold at their fueling station (as can producers of hydrogen who are eligible for incremental credits if they electrolysis). An LCFS credit is worth about $1.38/kg for LDV and $1.17/kg for HDV.

[36] Under the conditions: 40% is sourced from renewables, can only generate HRI credits for 15 years, station's dispensing capacity is less than or equal to 1,200 kg/day, must apply by 2025, and total HRI credits cannot exceed 2.5% of the total LCFS program deficits.

Unlike every other state, Utah specifically targets the supply chain aspect of hydrogen as an incentive to boost the production of hydrogen in the state. Three major policy support mechanisms for hydrogen production, storage, and transportation have been introduced:

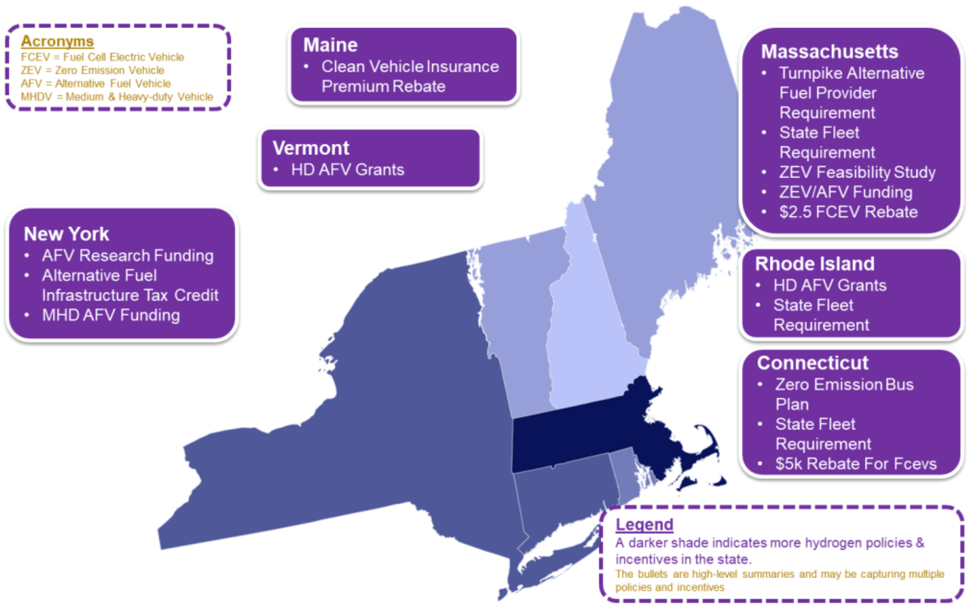
- Hydrogen Fuel Production Incentives (Utah Code §59-5-102)
  - Businesses that convert natural gas to hydrogen or produce natural gas to be used in hydrogen production are eligible for an "oil and gas severance" tax credit (up to $5M/year)
- The High-Cost Infrastructure Development Tax Credit (Utah Code §63M-4-600)
  - A facility that stores, produces, or distributes hydrogen for use in transportation, electricity, or industrial use is eligible for a non-refundable tax credit of 30% of qualifying state revenue generated during a tax period. The total credit is 50% of the cost of the infrastructure investment.
- The Throughput Infrastructure Fund (Utah Code §35A-8 308-309)
  - Pipelines that transport hydrogen or facilities that store, produce, or distribute hydrogen for use in transportation, electricity, or industrial use are eligible to apply for loans or grants from this $53M fund.

In Colorado, the "Retail Hydrogen Fueling Station Regulations" (Code of Colorado §1101-17) provides a standard under which the Colorado Department of Labor and Employment enforces rules concerning the development of stations.[37]

The Eastern U.S. has seen various hydrogen policies and incentives as well, primarily in New York and New England. As seen in Figure 6, all of these incentives are focused on transportation in the form of alternative fuel (AFV) or ZEV grants, research funding, and tax credits as well as state fleet requirements. Massachusetts and Connecticut provide $2.5k and $5k rebates, respectively, for FCEVs.

[37] The rules include inspections, specifications, shipment notification, record keeping, labeling of containers, use of meters or mechanical devices for measurement, submittal of installation plans, and minimum standards for the design, construction, location, installation, and operation of stations.

Figure 6. High level policies, incentives, and standards for hydrogen in New England and New York



Many of the western states and eastern states adopted joint policy initiatives to boost the consumption of hydrogen. For instance, ten states in 2014, with updated actions in 2018, collectively signed a Memorandum of Understanding (MOU) calling for a goal of 3.3 million ZEVs by 2025.[38] In addition, a collection of states specifically target ZEV deployment for MDVs through an MOU that aims for 100 percent ZEV truck and bus sales by 2050, with an interim target of 30 percent by 2030.[39] Hydrogen FCEVs are rarely called out specifically, but are eligible as Zero Emission Vehicles.

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[38] States include California, Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, Rhode Island, and Vermont.

[39] This includes all the aforementioned states plus Colorado, D.C., Hawaii, North Carolina, Oregon, Pennsylvania, and Washington

3. Opportunities for Hydrogen in Colorado

This chapter provides an overview of opportunities for hydrogen specific to Colorado. First, E3 examined the costs of producing hydrogen in Colorado, as well as specific costs and opportunities for the transportation and storage of hydrogen. Based on these production costs, E3 estimated the cost-effectiveness of hydrogen deployment in different end-use applications, comparing the use of hydrogen to decarbonization alternatives in several major sectors. Opportunities for hydrogen are translated to three scenarios for the deployment of hydrogen in the state to account for mid- to long-term uncertainties on the costs, feasibility, and regulatory landscape of a hydrogen economy.

3.1. Costs of producing hydrogen in Colorado

The hydrogen cost analysis for this study focuses on two low-carbon hydrogen production pathways: (a) SMR with CCS, and (b) electrolysis powered by off-grid (dedicated) renewable energy. In addition, E3 assessed the potential demand for hydrogen in the power sector based on curtailed renewable energy and gas peaking generation, as discussed in section 3.2.1.

Figure 7 shows the delivered hydrogen costs assumed for this study. Delivered cost includes the cost of production, storage, and transportation (excluding distribution and end-use costs). Inputs and assumptions for hydrogen cost estimates are consistent with previous E3 studies,[40,41] with fuel and energy costs updated for Colorado. Renewable energy is assumed to be derived from off-grid wind or solar resources in Colorado, with average capacity factors of 48% and 28%, respectively. Because of the uncertainty in the cost trajectory of electrolysis, Figure 7 shows a range of costs based on optimistic versus conservative electrolyzer cost assumptions. The “Least-Cost Renewable” pathway shows the lowest cost of hydrogen production based on either wind or solar resources:

- Under conservative electrolyzer cost assumptions, the least-cost renewable pathway is based on hydrogen production from wind resources.
- Under optimistic electrolyzer assumptions, the least-cost renewable pathway is based on solar resources from 2035 onwards.[42]

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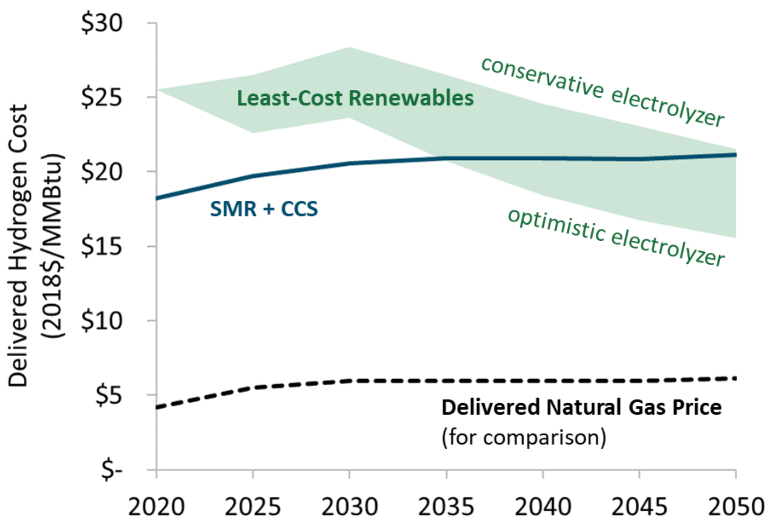
[40] Energy and Environmental Economics, Inc. Hydrogen Opportunities in a Low-Carbon Future: An Assessment of Long-Term Market Potential in the Western United States 2020. https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf

[41] California Energy Commission. The Challenge of Retail Gas in California’s Low-Carbon Future: Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use. 2019. https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf

[42] Hydrogen production costs are sensitive to the costs of electrolyzers and input costs of energy. When electrolyzer costs are high (both in the conservative scenario and in early years in the optimistic scenario), wind resources are ‘preferred’ over solar for its higher capacity factor, which translates into higher utilization of the electrolyzer and lower overall cost. When electrolyzer costs are low, hydrogen production costs are more sensitive to the cost of input energy, preferring solar over wind as the costs of solar are expected to drop on the medium term.

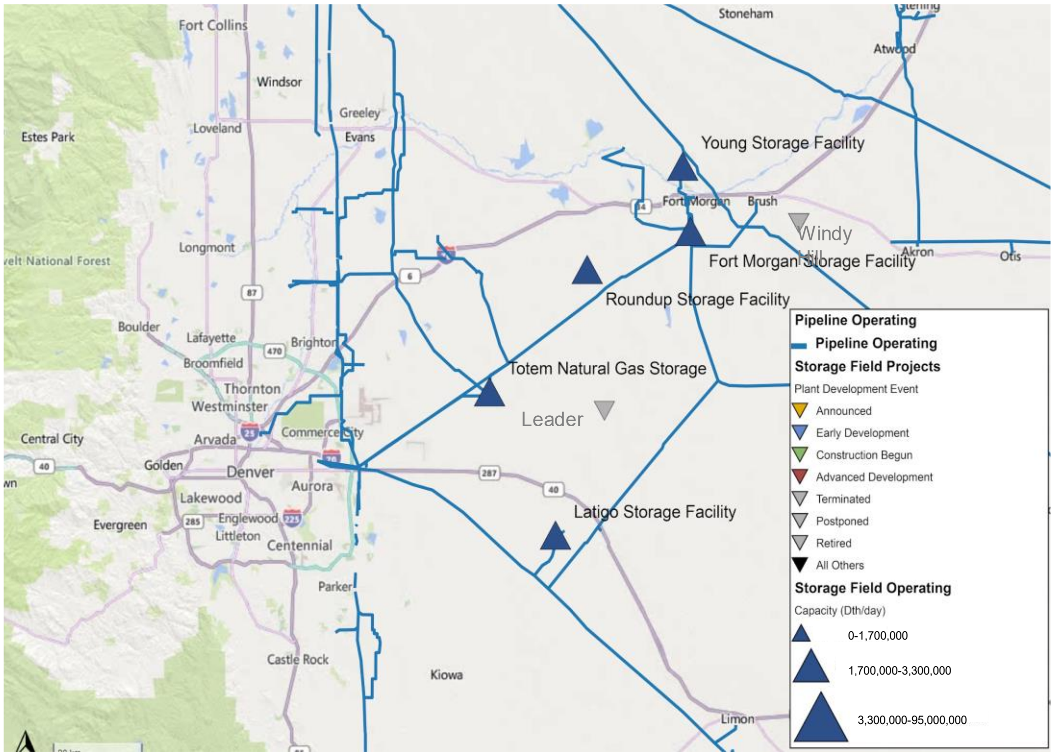
Figure 7 shows that hydrogen produced from renewables could achieve cost parity with hydrogen from SMR with CCS by the mid-2030s, although the exact timing is sensitive to the electrolyzer cost and performance trajectory assumed. A potential opportunity for Colorado could be to leverage its existing oil and gas infrastructure to jumpstart a market that relies on low-carbon hydrogen pathways such as SMR with CCS (e.g. by retrofitting the existing oil refinery), and transition to renewable hydrogen when it becomes a more cost-competitive option. Note that the data source used for this study did not provide a range for SMR/CCS costs (see Appendix B). The analysis therefore assumed a single cost trajectory for SMR with CCS in this study, recognizing that future SMR and CCS costs are subject to uncertainties such as the natural gas price, regulation on CCS and GHG emissions, and technology advancement.

Figure 7. Estimated delivered hydrogen cost trajectories used for this study.



All cost scenarios in Figure 9 assume dedicated new hydrogen pipelines and new salt cavern underground storage. In addition, existing gas infrastructure in Colorado, shown in Figure 8, could potentially be converted to be compatible with hydrogen, which, depending on location and asset specific characteristics, may result in cost advantages over developing greenfield infrastructure. Specifically, many existing underground gas storage facilities are relatively close to population centers in Colorado. These facilities are all depleted hydrocarbon fields and could potentially be converted for hydrogen storage due to geologic similarity. Existing gas pipelines or pipeline right-of-way could potentially be used for hydrogen transport, either through blending or dedicated pipelines (conversion or new construction). The technical feasibility and cost implications of converting existing gas infrastructure for hydrogen would need to be further assessed. Alternatively, in the power sector, electricity transmission could be used to bring power from co-located hydrogen production, geologic storage, and power plant facilities to load centers in populous or industrially-intensive portions of the state.

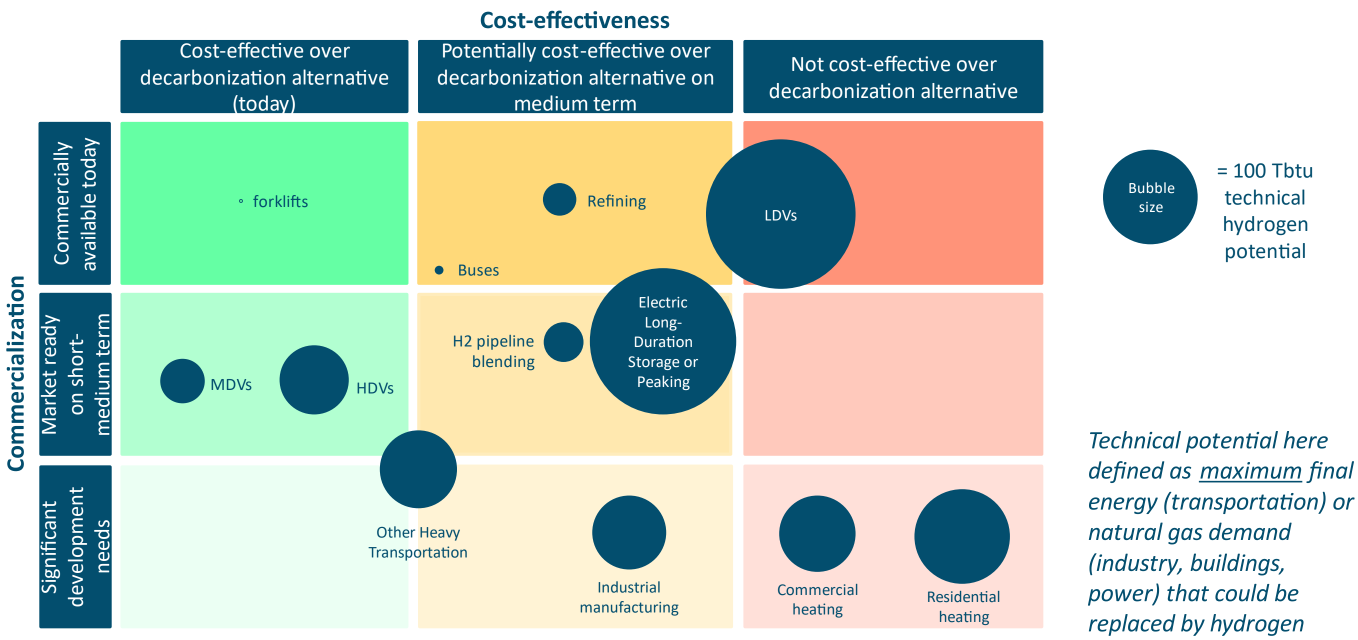
Figure 8. Existing gas pipeline routes and storage facilities in Colorado



3.2. Opportunities by end-use application

This section provides an overview of opportunities for hydrogen by end-use application in Colorado. The technical potential, cost-effectiveness and level of commercialization by end-use application are summarized in Figure 9. This figure shows the technical potential for hydrogen consumption in end-use applications, defined as the maximum final energy demand that could technically be replaced by hydrogen. As this chapter outlines, E3 expects the most promising applications for hydrogen consumption in the short term in the MHDV sectors. In these sectors, hydrogen is already cost-effective over decarbonization alternatives and ready for commercialization with the increase of a refueling station network and more availability of vehicles on the road. Additionally, E3 expects the application of hydrogen in power generation to provide significant potential in the medium term, especially as decarbonization targets become more stringent and the need for long duration storage increases. Neither the use of hydrogen in LDVs or in buildings is expected to become cost-effective over decarbonization alternatives in the short term, but hydrogen may provide other benefits to consumers and to the energy system as a whole that warrant further long-term investigation.

Figure 9. Conceptual overview of mid-term (2030) hydrogen potential in Colorado



3.2.1. Power sector

Advantages of hydrogen for long-duration storage

Some of the most promising applications of hydrogen can be found in a highly decarbonized power sector. In this case, hydrogen could provide value to the grid in the form of a zero-carbon fuel for use in existing gas turbines (with necessary upgrades to handle hydrogen combustion) or long-duration energy storage to balance renewable generation on a multi-day to seasonal scale. For these applications, hydrogen will likely be used to provide zero-carbon firm energy and capacity during sustained periods of low renewable outputs. Incorporating long-duration energy storage or other forms of zero-carbon firm energy technologies could avoid overbuilding weather-dependent renewables and lower the costs of achieving a deeply decarbonized, highly reliable grid. These benefits have been shown in numerous studies across various jurisdictions and climates.[43]

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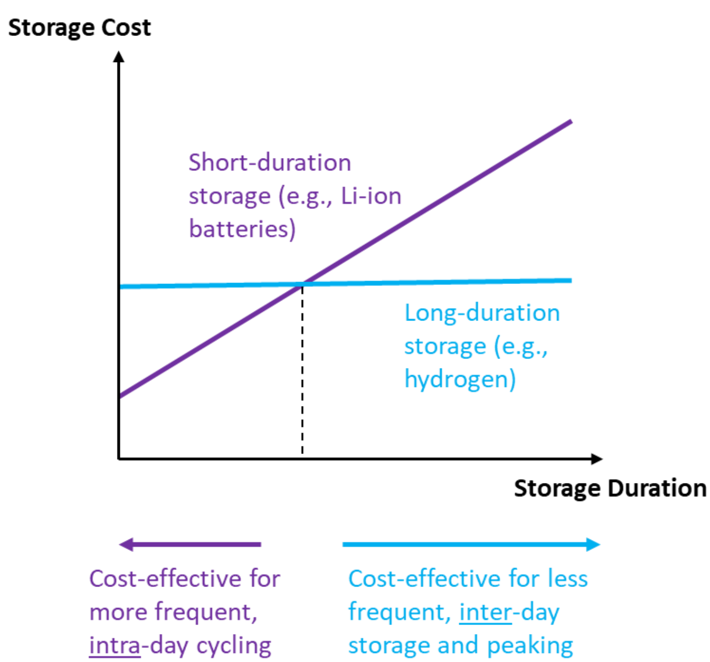
[43] Example studies include: (a) Sepulveda, N. A., Jenkins, J. D., de Sisternes, F. J., & Lester, R. K. (2018). The role of firm low-carbon electricity resources in deep decarbonization of power generation. *Joule*, 2(11), 2403-2420. (b) E3. Resource Adequacy in the Pacific Northwest. 2019. https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf. (c) Dowling, J. A., Rinaldi, K. Z., Ruggles, T. H., Davis, S. J., Yuan, M., Tong, F., Lewis, N. S. & Caldeira, K. (2020). Role of long-duration energy storage in variable renewable electricity systems. *Joule*, 4(9), 1907-1928. (d) E3. Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future. 2020. https://www.ethree.com/wp-content/uploads/2020/11/E3-EFI_Report-New-England-Reliability-Under-Deep-Decarbonization_Full-Report_November_2020.pdf. (e) Long, J. C., Baik, E., Jenkins, J. D., Kolster, C., Chawla, K., Olson, A., Cohen, A., Colvin, M., Benson, S. M., Jackson, R. B., Victor, D. G., & Hamburg, S. P. (2021). Clean Firm Power is the Key to California's Carbon-Free Energy Future. *Issues in Science and Technology*. https://issues.org/california-decarbonizing-power-wind-solar-nuclear-gas/. (f) Sepulveda, N. A., Jenkins, J. D., Edington, A., Mallapragada, D. S., & Lester, R. K. (2021). The design space for long-duration energy storage in decarbonized power systems. *Nature Energy*, 6(5), 506-516.

The key reason that hydrogen can provide cost-competitive long-duration energy storage is that hydrogen can be stored in large quantities at low cost when underground storage (e.g., salt caverns) is available (see Chapter 2 for a detailed discussion on storage options). The low cost of energy storage is advantageous because the total cost of a storage device scales with storage duration:[44]

$$total\ storage\ cost\ \left(\frac{\$}{kW}\right) = capacity\ cost\ \left(\frac{\$}{kW}\right) + energy\ cost\ \left(\frac{\$}{kWh}\right) \times storage\ duration\ (hr)$$

Figure 10 demonstrates this relationship by illustrating how total storage cost changes as a function of storage duration. Conventional batteries such as Li-ion batteries are likely more cost-competitive for short-duration applications such as shifting energy within the day. Their capacity costs are comparatively lower than long-duration storage options such as hydrogen (capacity costs include electrolyzers and gas turbines). In contrast, hydrogen is likely more economic in longer-duration applications such as seasonal energy storage because energy storage in the form of hydrogen can be very cost-effective provided that underground storage is available.

Figure 10. Illustrative comparison of storage costs as a function of storage duration



Round-trip efficiency is one variable not shown in Figure 10. Typical ranges of round-trip efficiency for Li-ion batteries and long-duration hydrogen storage are 80-90% and 20-30%,[45] respectively. Li-ion batteries

[44] The units in this equation correspond to upfront costs. The same equation can be used to calculate levelized costs, with units in $/kW-yr or $/kWh-yr.

[45] Assuming a conversion efficiency of 70-80% for alkaline electrolyzers, and thermal efficiency of about 30% for combustion turbines (CTs).

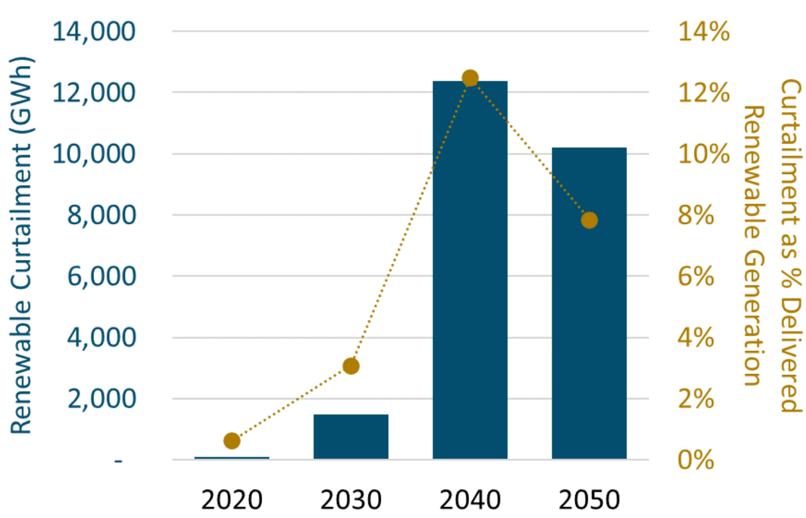
are thus more efficient for frequent, intra-day cycling. The lower round-trip efficiency of long-duration storage, on the other hand, is outweighed by its ability to provide economic energy storage on longer timescales. Long-duration storage, therefore, will likely occupy a different functional space than short-duration storage in a future grid by providing system stability during multiday periods of low renewable generation. It is expected to be discharged much less frequently than Li-ion batteries and other forms of short-duration storage.

Assessing hydrogen demand in the power sector

The power sector analysis in this study relied on previous modeling results that are consistent with the electricity portfolios from the *Colorado GHG Pollution Reduction Roadmap*.[46] Specifically, E3 used curtailment results to estimate hydrogen production and natural gas generation results to estimate hydrogen demand.

To reflect the role of hydrogen as long-duration storage, especially in the near- to medium-term when the cost of renewable hydrogen is relatively high, E3 first assessed the potential of hydrogen production from curtailed renewable energy. The annual curtailment levels are shown in Figure 11. Between 2020 and 2040, annual curtailed energy increases with time as more renewable resources are built to meet increasingly stringent GHG targets. By 2050, more energy storage and low-carbon firm capacity are built to meet GHG targets and reliability needs, which in turn helps balance renewable generation and reduce curtailment. As a result, curtailed energy is lower in 2050 than in 2040.

Figure 11. Estimated annual renewable electricity curtailment available for hydrogen production



To estimate the hydrogen production potential from curtailed renewables, electrolyzer capacity is incrementally added to the optimized resource portfolios. Hydrogen production is calculated from curtailed energy absorbed by the electrolyzer on an hourly basis. The technical potential of hydrogen production is indicated by the point where hydrogen production levels off with additional electrolyzer

[46] Colorado Energy Office. GHG Pollution Reduction Roadmap. https://energyoffice.colorado.gov/climate-energy/ghg-pollution-reduction-roadmap.

capacity. Based on this analysis, hydrogen production from curtailed renewables in Colorado can potentially reach 170-220 thousand metric tons per year in the 2040-2050 timeframe (see Appendix B).

On the demand side, a potential role for hydrogen in the power sector is the replacement of natural gas supply for electric peaking generation. In this application, hydrogen could potentially be supplied from curtailed off-grid renewables and used in gas turbines as a zero-carbon fuel. Hydrogen could play a bigger role as a peaking resource in the long run when renewable hydrogen production becomes more cost-competitive, and emissions targets become more stringent. To estimate the potential of hydrogen demand for peaking, E3 assessed the electricity generated from natural gas over time based on the modeling results consistent with the *GHG Pollution Roadmap*, as shown in Figure 12.

Figure 12. Annual gas generation results used in this analysis

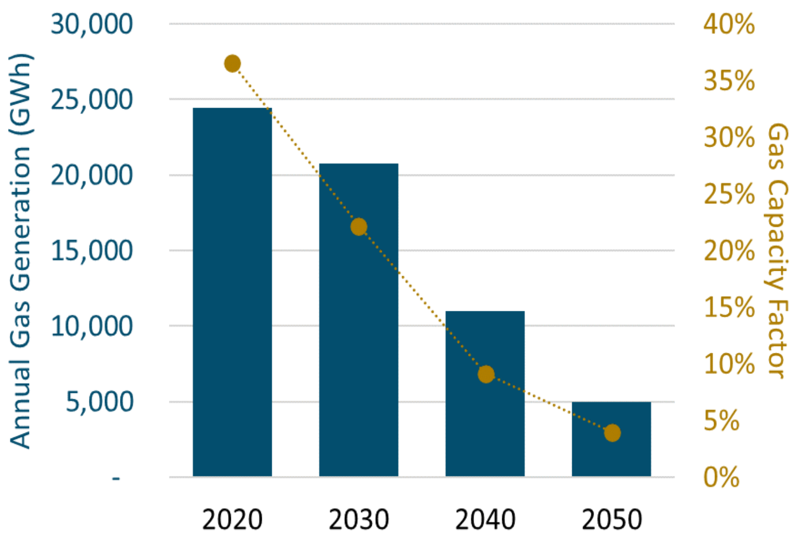


Figure 14 shows that gas generators are used primarily for energy in the 2020-2030 timeframe. In 2050, the average capacity factor from the entire gas fleet is about 4%, which indicates that natural gas is primarily used for peaking by this point in time. In a scenario where hydrogen is more cost-competitive than natural gas (especially with a stringent GHG constraint in place) or other zero-carbon fuel counterparts, hydrogen (supplied entirely by curtailed Colorado electricity) could potentially replace natural gas for peaking in the power sector by 2050.

3.2.2. Transportation sector

Hydrogen pump prices

As noted in Chapter 2, the majority of U.S. hydrogen use in the transportation sector is today concentrated in California while international use is highest in jurisdictions with ambitious hydrogen targets for both LDVs and MHDVs. In Colorado, the infrastructure for hydrogen in the transportation sector is currently limited. In 2020, Colorado State University acquired the first public hydrogen fuel station to enable research projects focused on hydrogen. Prior to that, NREL launched a hydrogen fueling station dedicated for research purposes as part of its Hydrogen Infrastructure Testing and Research Facility [47]

One of the biggest obstacles for the large-scale adoption of FCEVs is hydrogen's high pump price. California, the only state with active hydrogen pump stations, generally sees prices ranging from $10-15/kg.[48] This figure is about three to six times higher than Colorado's average gasoline and diesel rates at the pump: $2.5/kg and $3.4/kg, respectively.[49]

Figure 13 gives a breakdown of costs for a typical refueling station in Colorado in 2020, 2035 and 2050 using hydrogen from renewable electricity.[50] As shown in this figure, the capital cost of the refueling station itself today makes up more than 50% of the final pump price. The rest is largely made up of hydrogen production costs and operation and maintenance (O&M) costs. On-site production in this figure refers to hydrogen produced through grid electricity and stored in pressurized tanks at the site of dispensing. Off-site production indicates hydrogen is produced by dedicated off-grid solar, stored at a geological site, and then transported to the dispensing station by either trucks or pipeline.[51] E3's analysis shows that pump prices using off-site hydrogen production remain the more cost-effective option compared to on-site production, both now and in the future, as onsite electrolyzers using electricity from the grid are faced with higher electricity prices than those with access to dedicated off-grid electricity. However, off-site production, especially with transportation by pipeline, requires more advanced infrastructure that is likely to become viable only at scale.

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[47] See: https://engr.source.colostate.edu/csu-acquires-public-hydrogen-fuel-station-a-first-for-the-state-of-colorado/; https://www.nrel.gov/news/press/2015/20582.html

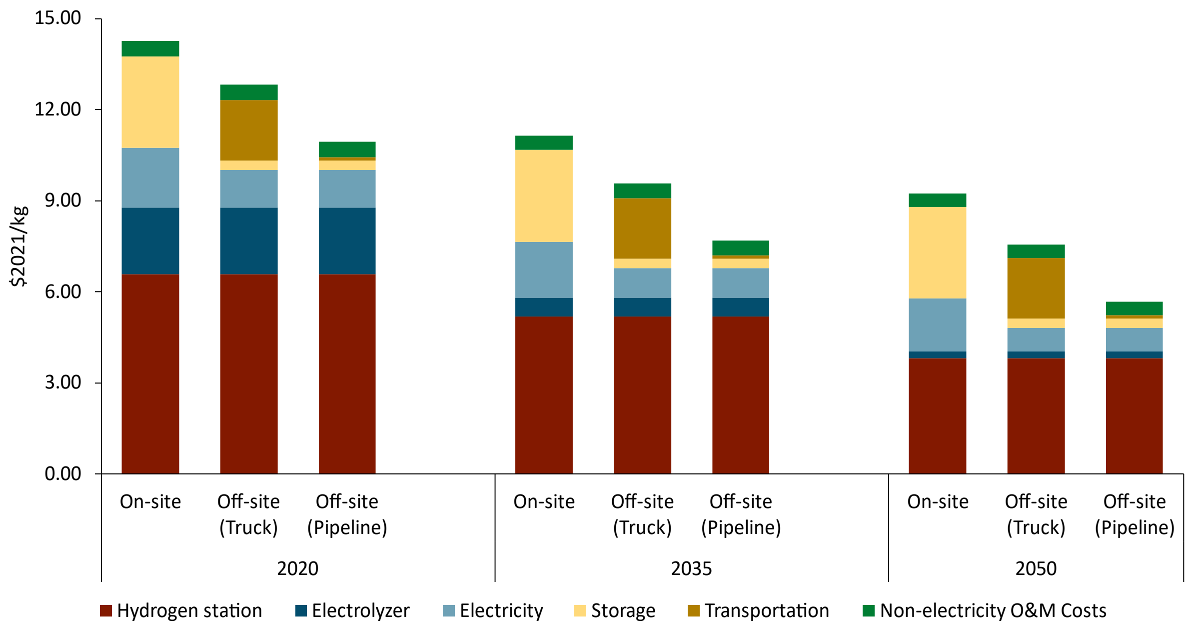
[48] Hydrogen Station Network Self-Sufficiency Analysis per Assembly Bill 8 (ca.gov)

[49] Derived from: https://gasprices.aaa.com/?state=CO

[50] 350 bar station with capacity of 1,000 kg/day. E3 uses the standard pressure for an HDV station rather than an LDV (700 bar) station, as the HDV segment is likely to become a more competitive sector. A higher pressure station would raise the costs shown on Figure 13.

[51] Pipelines are operationally significantly cheaper than trucking hydrogen but would require high upfront costs to build the necessary infrastructure.

Figure 13. Estimated hydrogen refueling pump prices in Colorado



As shown in Figure 13Figure 13, pump prices across all scenarios are expected to decline as electrolyzer costs decline and station cost economics improve with scale and higher utilization rates. In the analyses on hydrogen cost-effectiveness shown below, E3 uses the off-site pump price with pipeline transportation.

Cost-competitiveness of hydrogen in transportation

Zero emission vehicles today make up around 1% of Colorado's vehicle stock, mostly consisting of BEV or plug-in hybrids concentrated in the LDV sector. However, the market options for hydrogen fuel cell cars are growing. For example, Hyundai's Nexo, comparable to the electric Tesla Model Y, is one of the recent offerings in the compact SUV segment, which shows that FCEVs are an available alternative to BEVs today.

E3 assessed the cost-effectiveness of LDVs, MDVs, and HDVs compared to BEVs and Internal Combustion Engine (ICE) vehicles, as shown in Figure 14. In the MDV and HDV segment, E3 analyzed that hydrogen is a cost-effective solution compared to electric vehicles, both now and in the future, on a per weight basis. An important reason for this cost-effectiveness is that heavy duty electric vehicles are projected to have a significantly lower carrying capacity than diesel or FCEV counterparts.[52] Because most public roadways have an 80,000lb weight limit for vehicles, the greater unladen weight of electric trucks is a competitive disadvantage because it results in lower cargo capacity and therefore higher costs per ton of cargo shipped.

For MHDV, at today's diesel prices, hydrogen would only compete with a standard diesel MHDV at a price of $5-6/kg on an operating cost ($/ton-mile) basis. Approaching 2030 however, with assumed improved

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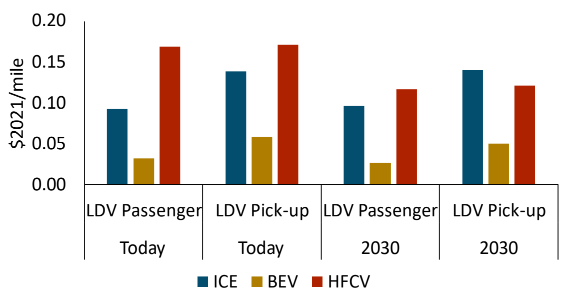
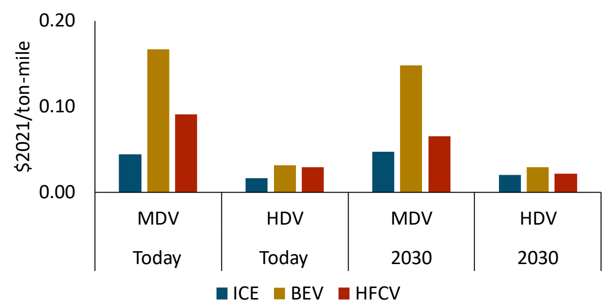
[52] E3 (June 2020). Hydrogen Opportunities in a Low-Carbon Future: An Assessment of Long-Term Market Potential in the Western United States.

fuel economies for MHDV and expected increase in diesel prices[53], hydrogen pump prices would only need to fall to $6-8/kg to become competitive on an operating cost ($/ton-mile) basis. This is foreseeable in the future as production and station costs of hydrogen fall, pushing the pump price down coupled with the greater fuel economy and equivalent weight carrying capacity of FCEVs.

In the LDV segment, E3 estimates that BEVs will remain a more operationally cost-effective option both today and in the next decade as a result of significantly better fuel economies and lower fuel costs than equivalent LDV FCEVs.

Figure 14. Economics of HFCEV versus alternatives. Note: figure shows an operational cost comparison only





It is important to note that this analysis only considers the operational economics of hydrogen versus decarbonization alternatives. Numerous factors will impact a customer's adoption of a vehicle, such as capital costs, tax credits, refueling times and accessibility. For instance, Colorado's elevation features may warrant the adoption of hydrogen vehicles over electric vehicles given their similar characteristics to ICE vehicles for some applications. On the other hand, the entrance of FCEVs into the market is rather delayed compared to BEVs and the analysis above does not take upfront capital costs of vehicles into account. For example, while a conventionally-fueled (ICE) Honda CR-V costs under $30,000 and Tesla 2021 Model's Y BEV is about $50,000, the 2021 Hyundai Nexo FCEV is $59,000.[54] Additionally, FCEVs are only viable with the introduction of a sufficient refueling station network.

Finally, while the technology is significantly less mature than for on-road transportation, the global aviation industry is considering using hydrogen as a means to reduce the carbon emissions of commercial jet airline travel. The advantage of using hydrogen directly in aviation over other transportation applications is that one can reduce the overall amount of fueling infrastructure required per unit energy of fuel delivered, given that planes only refuel at airports rather than needing an extensive on-road fueling infrastructure. However, the low volumetric energy density of hydrogen poses a challenge to allowing long distance flight. Alternatively, hydrogen may be useful for creating synthetic liquid aviation fuels, which will cost significantly more than hydrogen but can use existing planes and fueling infrastructure.[55]

[53] Diesel fuel prices are expected to increase by 25% by 2030, to $4.2/kg (EIA 2021 Energy Outlook – Diesel Fuel Price - Mountain Region. Annual Energy Outlook 2021 (eia.gov))

[54] See: 2021 Honda CR-V Prices, Reviews, and Pictures | Edmunds; 2021 Tesla Model Y Prices, Reviews, and Pictures | Edmunds; 2021 Hyundai NEXO Prices, Reviews, and Pictures | Edmunds

[55] See: https://www.ft.com/content/7099d84c-07b8-4970-b826-ac28b4e59841

Biofuels may outcompete hydrogen for this application should carbon-neutral biofuel production increase significantly. Given its significant long-term development needs, this Roadmap does not consider the use of hydrogen in the aviation industry on a medium-term timescale.

3.2.3. Building sector

To date, hydrogen has not been used at scale as a source of heating in buildings in North America and beyond. However, several studies have explored the viability of replacing natural gas infrastructure with large-scale low-carbon hydrogen infrastructure, especially in Europe. The most well-known example is the H21 North of England project that presents a conceptual design for converting the North of England's natural gas distribution network to hydrogen between 2028 and 2035.[56]

The use of hydrogen in buildings to date represents significant challenges. Apart from the lack of hydrogen supply, converting buildings to a hydrogen network, if hydrogen were to supply 100% of building demands, would require substantial upgrades to the distribution pipeline system and consumer appliances. The blending of limited volumes of hydrogen into the existing pipeline infrastructure could avoid the need for infrastructure upgrades, although more pilots and demonstration projects on this approach are required. Colorado's SB 21-264, which requires gas distribution utilities to develop clean heat plans to achieve decarbonization targets, allows utilities to include low carbon hydrogen and related pilot projects in their plans.

Colorado currently has relatively low natural gas prices compared to other parts of the country, making standard gas furnaces and boilers the more cost-effective option over electric heat pumps in existing single family homes today, as shown on Figure 16. Yet with more stringent decarbonization targets, electric heat pumps are expected to become the most cost-effective decarbonization solution on an operational cost basis, significantly outweighing the costs of hydrogen boilers as a result of efficiency benefits. However, it is important to note that Colorado's cold climate may warrant the need for additional heating supply in winter. As building heating demands are highly seasonal, with large peak loads coinciding with cold-snaps, large-scale building electrification may create peak capacity and resource adequacy challenges. As noted in the *GHG Pollution Roadmap*, these peak impacts can be mitigated through load flexibility in space heating and a balanced mix of technologies, for instance by providing combustible fuel backups. Therefore, E3 estimated the costs of using a dual fuel technology in single family homes that uses hydrogen in the form of synthetic natural gas (SNG) to supply heating demands in winter. Using SNG over pure hydrogen would avoid costly pipeline and appliance retrofits that would be needed for a 100% hydrogen system. Figure 15 shows that a dual fuel technology (using a heat pump combined with SNG for winter supply) is more cost-effective than hydrogen boilers in the medium term, although less cost-effective *on a consumer basis* compared to electric heating. However, the societal value of using SNG in winter periods would need to be assessed on system level to provide an accurate assessment of the value of hydrogen in buildings, which is beyond the scope of this study. It is important to note that the cost-effectiveness of SNG for dual fuel heating in large part depends on the cost and availability of other types of decarbonized gases, such as biomethane, which provide a direct alternative to the use of hydrogen-based gases in winter.

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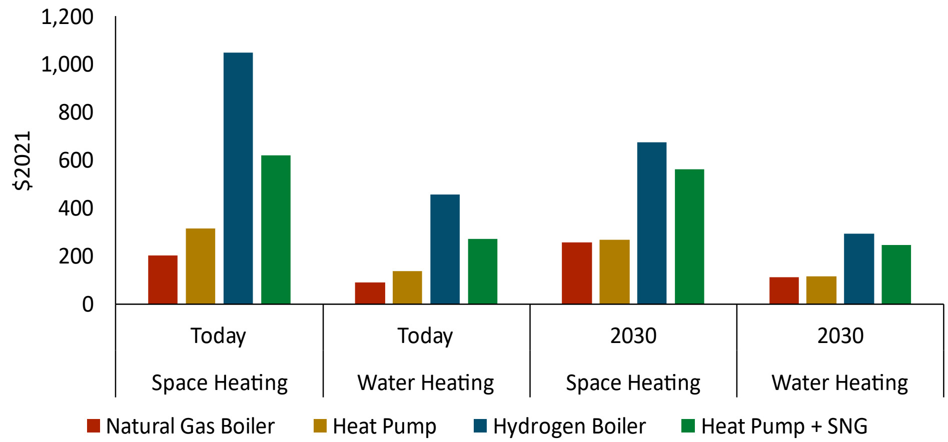
[56] See: https://h21.green/projects/h21-north-of-england/

Figure 15. Typical annual operating cost for heating a single family home in Colorado



3.2.4. Industry

Given the current consumption of hydrogen in the industrial sector across North America, the industry is a likely candidate for consuming low-carbon hydrogen in the medium to long term under more stringent decarbonization targets. Colorado's food and chemical manufacturing industries have a relatively large demand for process heating and demand for hydrogen already exists in the oil refining industry.[57] The oil refinery owned by Suncor Energy is the largest consumer of hydrogen today, with approximately 19,000 metric tons/yr hydrogen production capacity.[58] Transitioning this plant's hydrogen production to industrial uses besides oil refining would require separate economic and operational feasibility analysis, and the steam methane reforming plant would have to be retrofitted with CCS, or some other means of decarbonizing hydrogen.

In other industrial sectors, hydrogen has the potential to displace natural gas and coal demand used for (high-temperature) heating processes. In Colorado, this opportunity is especially large for existing applications with limited decarbonization opportunities, such as thermochemical processes and food processing, where hydrogen could be used as a syngas or combustion fuel to replace natural gas.

The heterogenous nature of industrial energy demands complicate a robust assessment of the use of hydrogen over direct electrification of industrial processes, CCS or alternative low-carbon fuels. Generally speaking, although the capital costs (plant upgrade) of displacing natural gas with hydrogen are limited, the operational (fuel) costs of hydrogen would need to be cheaper than the cost of alternative fuels or combusting natural gas with CCS in order for hydrogen to be competitive. E3 expects lower grade temperature industrial processes, for instance providing hot water and steam, to be more suitable for electrification purposes due to efficiency advantages. In addition, E3's modeling suggests that, on average, both green and blue hydrogen will likely be more expensive than natural gas with CCS. However, since not all regions or industrial applications are suited for CCS, hydrogen could be a viable decarbonization alternative available for some industrial processes where electrification alternatives are not competitive.

[57] Based on NREL Industrial Energy Database; EIA Manufacturing Energy Consumption Survey (MECS)

[58] Hydrogen Analysis Resource Center: Captive, On-Purpose, Hydrogen Production Capacity at U.S. Refineries

These applications likely involve industrial processes that today combust natural gas at high temperature levels.

In the higher temperature grade applications mentioned above, the cost-competitiveness of hydrogen partly depends on the cost trajectory of hydrogen compared to the cost trajectory of biofuels, which provide a direct alternative for the replacement of natural gas. As more sectors compete for biofuels under tighter decarbonization targets in the next decade, hydrogen may become the more cost-competitive decarbonization alternative. Yet, the use of hydrogen for large-scale industrial applications would require significant infrastructure upgrades, either in the form of new-built dedicated pipelines or through retrofitting existing pipelines that allow the transportation of hydrogen. In some European regions, these infrastructure needs are assessed and developed on cluster-level, where concentrated industrial demand clusters are used to kickstart a hydrogen economy.[59]

3.3. Quantifying demand opportunities

To translate the opportunity for hydrogen in Colorado to potential annual demand, E3 developed three scenarios, or "world views", that vary in level of ambition and assumed trajectory on the competitiveness of hydrogen relative to alternatives in each sector of the economy. These scenarios are outlined below, with more detailed assumptions included in Appendix B.

+ **HB 1261 (Reference) Scenario:** Hydrogen demand is assumed to be consistent with the HB 1261 scenario developed in the *GHG Pollution Roadmap.* This scenario assumes that hydrogen plays a modest role in all sectors of the economy. Specifically, no hydrogen demand is assumed for the transportation or power sector, and up to 5% of hydrogen (by energy content) is blended into distribution pipelines by 2050 (linearly increasing from 2031) to serve buildings and industrial manufacturing.
+ **Growth Scenario:** In the Growth scenario, hydrogen is assumed to play an increasingly important role in medium- and heavy-duty transportation. Demand in industry, buildings, and the power sector all rely on pipeline hydrogen blending, which is assumed to reach 7% (by energy content) by 2050 (linearly increasing from 2026). This scenario reflects a worldview with optimistic cost trajectories for biogas and biofuels, and continued cost decline of low-carbon hydrogen in line with current expectations.
+ **Transformative Scenario:** In the Transformative scenario, hydrogen is assumed to have a substantial presence across all sectors of the economy. In the transportation sector, hydrogen continues to be a key decarbonization strategy for medium- and heavy-duty transportation, but also emerges in light-duty transportation as a result of favorable policies and consumer preferences. In industry, hydrogen is used as a dedicated source of heat for some high temperature processes. In buildings, hydrogen is used to supply heat during winter peaks in the form of SNG. In the power sector, hydrogen serves as long-duration storage by utilizing curtailed renewables in the near- to medium-term, and replaces natural gas peaking generation by 2050.

[59] See, for instance the NorthH2 project in the Netherlands: https://www.north2.eu/en/

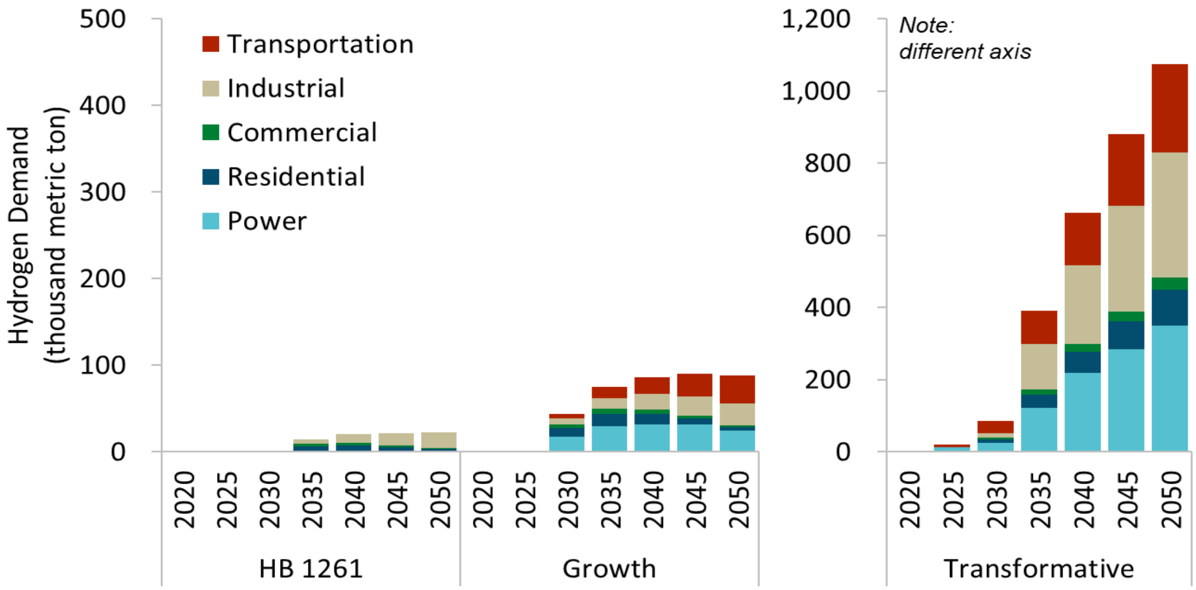
This scenario would rely on stimulating policies, extensive hydrogen infrastructure, steep cost declines of low-carbon hydrogen, and more conservative cost trajectories of biogas and biofuels.

The estimated hydrogen demand for the three scenarios is shown in Figure 16. In all scenarios, hydrogen demand is expected to increase from the late 2020s onwards to allow for production and infrastructure developments. In the HB 1261 scenario, hydrogen plays a modest long-term role, with an expected demand of around 30 thousand metric tons per year by 2050 as a result of hydrogen pipeline blending. In the Growth scenario, total hydrogen demand reaches about 45 thousand metric tons per year in 2030 and close to 100 thousand metric tons per year by 2050. In both the HB 1261 and Growth scenarios, hydrogen demand in buildings (commercial and residential) peaks around 2035-2040. In the Growth scenario, hydrogen demand in the power sector peaks around 2040. These peaks reflect that the decrease in gas consumption for buildings and power generation outpaces the increase in pipeline blending of hydrogen.

In the Transformative scenario, total hydrogen demand reaches around 85 thousand metric tons per year by 2030 and over 1 million metric tons per year by 2050. As an illustrative example, the total hydrogen demand in the Transformative scenario in 2050 would correspond to about 8 million metric tons of CO_2 emissions reduction per year.[60] The significant growth towards 2050 is mostly the result of the increasing reliance on hydrogen in the power sector, which is assumed to fully replace gas peaking generation by 2050 under stringent carbon targets, and on the use of dedicated hydrogen in industrial sectors. In addition, the scenario assumes a significant role for hydrogen in the transportation sector. Demand in the transportation sector reaches around 250 thousand metric tons per year by 2050, under this scenario around half of which accounted for by heavy duty transportation. It is important to note that across all of these sectors, significant infrastructure developments, as well as optimistic cost trajectories, will be required for this scenario to operationalize.

[60] Using the higher heating value of hydrogen at 142 GJ/metric ton. Assuming hydrogen displaces natural gas in power generation, buildings, and industry, with natural gas having an emissions factor of 117 lb/MMBtu per US EIA (https://www.eia.gov/tools/faqs/faq.php?id=73&t=11). Assuming hydrogen displaces transportation emissions at the 2020 average emissions rate that is consistent with the Colorado Energy Office *GHG Pollution Reduction Roadmap* (https://energyoffice.colorado.gov/climate-energy/ghg-pollution-reduction-roadmap).

Figure 16. Annual hydrogen demand estimated for Colorado by scenario



In addition to annual hydrogen demand, E3 estimated the annual costs to produce the hydrogen consistent with the demand figures in each scenario. These estimated costs are shown in Figure 17. A breakdown is shown by sector that is based on the "least-cost renewables" scenario with optimistic electrolyzer cost and efficiency assumptions, as outlined in Section 3.1. The ranges provided on the chart represent the "least-cost renewables" scenario with conservative electrolyzer assumptions on the high end, and the least-cost trajectory (with SMR + CCS before 2035) on the low end. The costs shown on this figure represent the total levelized costs of *delivered* hydrogen, including production, underground storage, and dedicated pipeline transportation. Both fixed costs (levelized capital costs, fixed O&M costs) and variable costs are included in these estimates.

Figure 17. Annual hydrogen cost estimated for Colorado by scenario

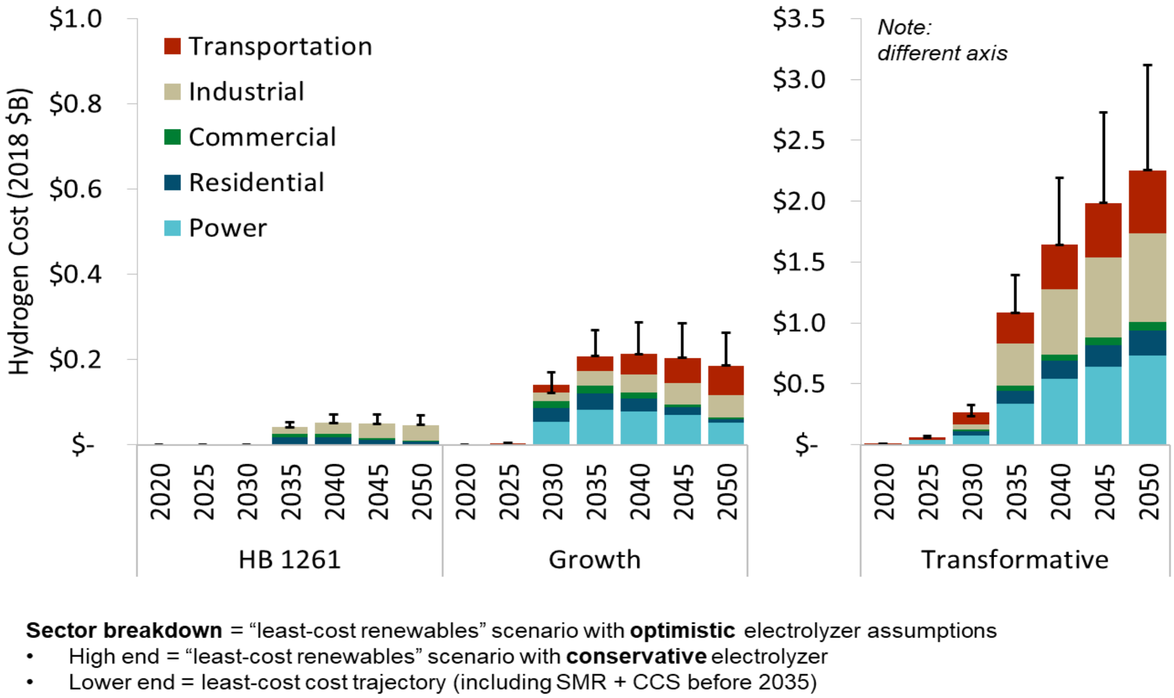


Figure 17 shows that between 2040 and 2050, annual costs for hydrogen reach about $60-80 million dollars in the HB 1261 scenario, and $200-300 million dollars in the Growth scenario. In the Transformative scenario, annual hydrogen costs can be as high as $2-3 billion dollars by 2050. For context, Colorado's 2020 GDP was about $390 billion dollars,[61] indicating that $2-3 billion dollars would be equivalent to 0.5-0.8% of the state's GDP in 2020.

3.4. Unlocking the economic potential

3.4.1. The hydrogen landscape in Colorado

Building a hydrogen economy requires participation from many players across a variety of sectors in the hydrogen value chain. From hydrogen production to end-use customers, the hydrogen supply chain involves a broad set of roles for commercial parties, utilities, governmental organizations and knowledge institutes. In Colorado, a network of players active in the hydrogen economy already exists. With its large presence of research bodies, network associations, technology providers and industrial players, Colorado is well suited for the development and scale-up of hydrogen in the region. Figure 18 provides an overview of the hydrogen landscape in Colorado, distinguishing several categories:

+ **Research & Development:** Colorado's large body of research organizations, universities and educational institutions provide an opportunity to lead the deployment of a hydrogen economy

[61] Data from U.S. Bureau of Economic Analysis, March 26, 2021 release. Colorado's 2020 GDP (preliminary) was 390,098.7 million current dollars.

in the state. Colorado is home to the National Renewable Energy Laboratory (NREL), a leading research facility specialized in the Research and Development (R&D) of renewable energy and energy systems integration. NREL has been active in a vast number of research activities related to hydrogen in Colorado. For instance, NREL launched a Hydrogen Infrastructure Testing and Research Facility aimed at testing hydrogen storage, compression and dispensing capabilities for fuel cell vehicle fueling.[62] In addition to NREL, the Colorado State University (CSU) Energy Institute provides data, analysis and testing of innovative hydrogen solutions. NREL and CSU, together with the University of Colorado, Boulder and the Colorado School of Mines form the Colorado Energy Research Collaboratory, an inter-institutional R&D collaboration conducting over $1 billion in scientific and technological research annually.[63]

+ **Technology & Market:** Technology providers play an important role in the hydrogen value chain both in and out of state, from developing and marketing fuel cell technologies to manufacturing electrolyzers and supplying innovative technological solutions. As an energy-rich region, Colorado is home to both traditional energy suppliers and cleantech developers. Clean Edge ranks Colorado among the top 10 states in cleantech leadership with its concentration of renewable energy suppliers, renewable energy, and storage equipment manufacturers and engineering businesses.[64] According to the Colorado Cleantech Industry Association (CCIA), Colorado's cleantech industry is rapidly growing, experiencing an employment growth rate within the sector of 9.6% between 2017-2019.[65] In addition, Colorado has ambitious renewable energy supply plans for the next decades. For instance, Xcel Energy in March 2021 submitted a Clean Energy Plan to the Colorado Public Utilities Commission that proposes the addition of 2,300 MW of wind, 1,600 MW of solar, and 1,300 MW of dispatchable resources between 2021 and 2030. In the hydrogen value chain specifically, a number of technology providers and industry suppliers are currently active. Examples include Vairex, a manufacturer of compressor systems for the fuel cell industry, Starfire Energy, a manufacturer of systems that generate ammonia from renewable energy, Lightning, a manufacturer of (among others) electric and FCEV trucks, Bayotech, a developer of SMR systems, and Versa Power Systems, a Solid Oxid Fuel Cell (SOFC) technology provider.

+ **Infrastructure:** The production, transportation and storage of hydrogen will involve a diverse set of market players. Which players will depend on whether hydrogen will be transported through pipelines or trucks. Hydrogen transportation by pipeline can be seen as a long-term, cost-effective strategy in a relatively mature market, in which gas utilities such as Xcel Energy and Black Hills Energy may play a role. Opportunities for hydrogen storage may exist by leveraging the many existing underground gas storage facilities relatively close to Denver; additional research would be necessary to evaluate whether these facilities are suitable for hydrogen storage. In addition, infrastructure opportunities exist for the deployment of hydrogen refueling stations, a market in which several players in Colorado, such as New Day Hydrogen, are currently active.

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[62] See: https://www.nrel.gov/hydrogen/hitrf.html

[63] See: https://www.coloradocollaboratory.org/about-the-collaboratory/

[64] See: https://cleanedge.com/reports/2017-US-Clean-Tech-Leadership-Index

[65] See: https://www.coloradocleantech.com/about/cleantech-in-colorado/

- **End-use:** Hydrogen can potentially play a role in many end-uses. At present, a few companies in Colorado are actively investigating or involved in the production and/or use of hydrogen. In Central Park, a Kroger distribution center operates over 200 fuel cell forklifts and operates infrastructure with liquid storage and multiple dispensers.[66] Suncor Energy, operator of the Commerce City Refinery, produces and uses hydrogen at a capacity of around 19,000 metric tons per year, currently from non-renewable sources.[67] The Roaring Fork Transportation Authority (RFTA) is investigating pilot programs on developing hydrogen production, storage, and fueling facilities for hydrogen-fueled buses. The RFTA plans to replace its aging bus fleet with an increasing number of zero emission vehicles over the next two decades. Other potential off-takers of hydrogen in Colorado include the transportation sector, large industrial facilities (for instance demand for process heating in the food manufacturing industry), and the electricity generation sector (using curtailed power to produce hydrogen for long duration storage), as well as local distribution companies that deliver gas to residential and commercial buildings.
- **Funds and Investors.** In 2020, the global hydrogen market received nearly $1.5 billion in investments, driven by fuel cell vehicles and buses, refueling stations and electrolyzers.[68] A recent report by Global Market Insights expects the global hydrogen market revenue to surpass $300 billion by 2027, indicating substantial growth of the market in the next decade.[69] In Colorado, the cleantech industry attracted $20.5 million in venture capital investments in 2019 from investors[58] and a financial landscape exists that has the potential to boost investments in the hydrogen economy. For instance, the Colorado Energy Office in 2019 helped launch the Colorado Clean Energy Fund to enhance investments in clean energy projects and the Rockies Venture Club in partnership with Traxion, CCIA, NREL and RMI formed the Colorado Cleantech Angels to invest in cleantech startups.
- **Network Associations and Coalitions:** A number of network associations and coalitions related to hydrogen and cleantech are currently active in Colorado. For instance, the Colorado Hydrogen Network represents a network of companies and organizations advancing innovative energy technologies. The Colorado Hydrogen Network was formed under the parent Colorado Cleantech Industries Association (CCIA), an organization dedicated to promoting Colorado's cleantech industry. In addition, the Denver Metro Clean Cities Coalition, Northern Colorado Clean Cities Coalition, and Southern Colorado Clean Cities Coalition are active in supporting actions that promote alternative fuels and petroleum reduction strategies in Colorado's transportation sector.
- **Government Agencies:** Government agencies play a role in the facilitation of a hydrogen economy in the state. State agencies such as the Colorado Energy Office (CEO), the Colorado Department of Transportation (CDOT), the Department of Public Health & Environment (CDPHE) and the

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[66] See: https://www.energy.gov/eere/articles/colorado-joins-hydrogen-and-fuel-cells-race

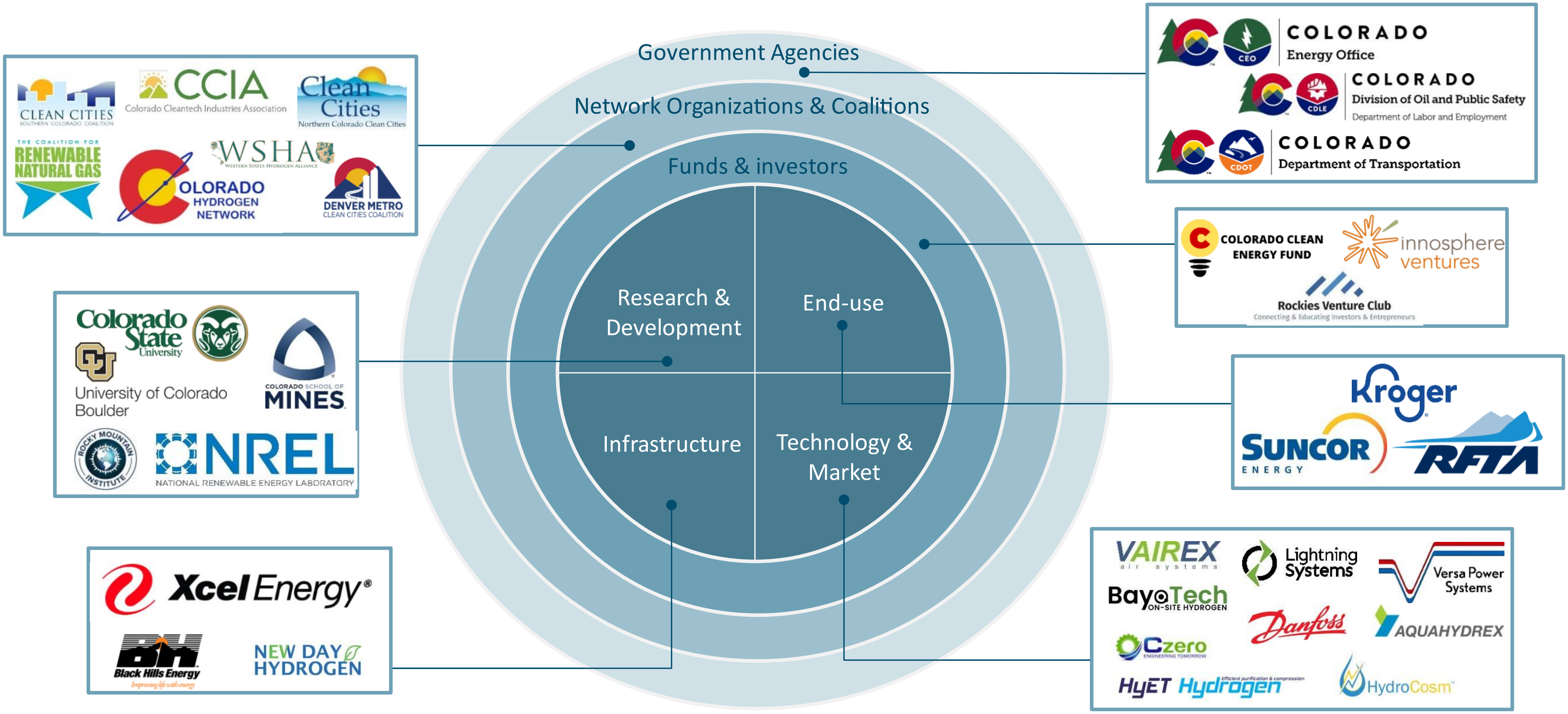
[67] Hydrogen Analysis Resource Center: Captive, On-Purpose, Hydrogen Production Capacity at U.S. Refineries

[68] BloombergNEF (2021). Energy Transition Investment Trends: https://assets.bbhub.io/professional/sites/24/Energy-Transition-Investment-Trends_Free-Summary_Jan2021.pdf

[69] See: https://www.globenewswire.com/news-release/2021/04/06/2204782/0/en/Hydrogen-Market-value-to-hit-300-billion-by-2027-Says-Global-Market-Insights-Inc.html

Division of Oil and Public Safety within the Colorado Department of Labor and Employment (CDLE), as well as city governments, are important in designing long-term plans, policies, regulations and codes that support and streamline the development of hydrogen in Colorado.

Figure 18. Current hydrogen landscape in Colorado



Note: Categories include examples of organizations currently active in the hydrogen economy in Colorado. The list is non-exhaustive.

3.4.2. Potential impact on employment

While there is little independent or rigorous research on the job implications of hydrogen deployment in existing literature today, E3 performed a high-level assessment of the effects of a hydrogen economy in Colorado. For this analysis, E3 only considered the effect on direct jobs, related to net employment effects on the supply-side of hydrogen.[70] Generally, these numbers are subject to significant uncertainties and should be used as an order of magnitude comparison, but not as an established predictor for economic impact.

E3 estimated direct job opportunities for Colorado based on metrics on renewable energy by Meyer & Sommer (2014) and Cameron & Van der Zwaan (2015). Based on these indicators, E3 estimates the high-level direct effects of hydrogen deployment on the manufacturing, construction and installation, and operation and maintenance of renewable hydrogen supply at between 6,000 – 12,000 jobs in 2030 (Figure 19).[71] Towards 2050, this number could grow to around 250,000 jobs in the Transformative scenario. It is important to note, however, that not all of these jobs are likely to occur in state. Especially for manufacturing jobs, for instance jobs associated with the production of fuel station or electrolyzer components, some products may be delivered from out of state. In addition, the production jobs represented in this figure are the *total number of jobs* attributable to hydrogen production in Colorado, not all of which are long-term.

The effect of the development of hydrogen refueling stations on employment was estimated by E3 using the JOBS H_2 model developed by Argonne National Laboratory.[72] E3 estimated the direct effects of hydrogen refueling stations development on employment at 2,000 jobs in 2050 in the Growth scenario and 17,000 jobs in 2050 in the Transformative scenario. These include station development jobs which would occur within one to two years before completion of a station to account for engineering and planning, as well as operation and maintenance jobs related to the station and the production and distribution of hydrogen.[73]

[70] The employment effects can be estimated on three levels: 1) Direct: Jobs related to core activities such as manufacturing, fabrication, construction, site development, installation, and O&M. 2) Indirect: Supply and support of the industry at a secondary level such as extraction and processing of raw material, marketing and selling, administration, and work performed by other bodies and organizations. 3) Induced: Jobs that arise from economic activities of direct and indirect employees. I.e.: wages for direct/indirect employees spent in unrelated industries.

[71] E3 took the median wind and solar employment factors from these ranges and applied those to the hydrogen market size estimated in the scenarios developed for Colorado in Task 5. The market size is estimated by the required electrolyzer capacity to meet hydrogen demand in the Growth and Transformative scenarios, which amount to 1.5 GW and 2.1 GW respectively in 2030 versus 1.3 GW and 15 GW respectively in 2050.

[72] This model represents an input-output (I-O) framework that was last updated in 2014, developed to help determine the direct and induced job impacts of hydrogen refueling stations both in their development and operational stage.

[73] Although the H2 JOBS model does report induced jobs, E3 does not include these in Figure 4 above as induced jobs have the least amount of certainty.

Figure 19. Estimated employment effects of a hydrogen economy

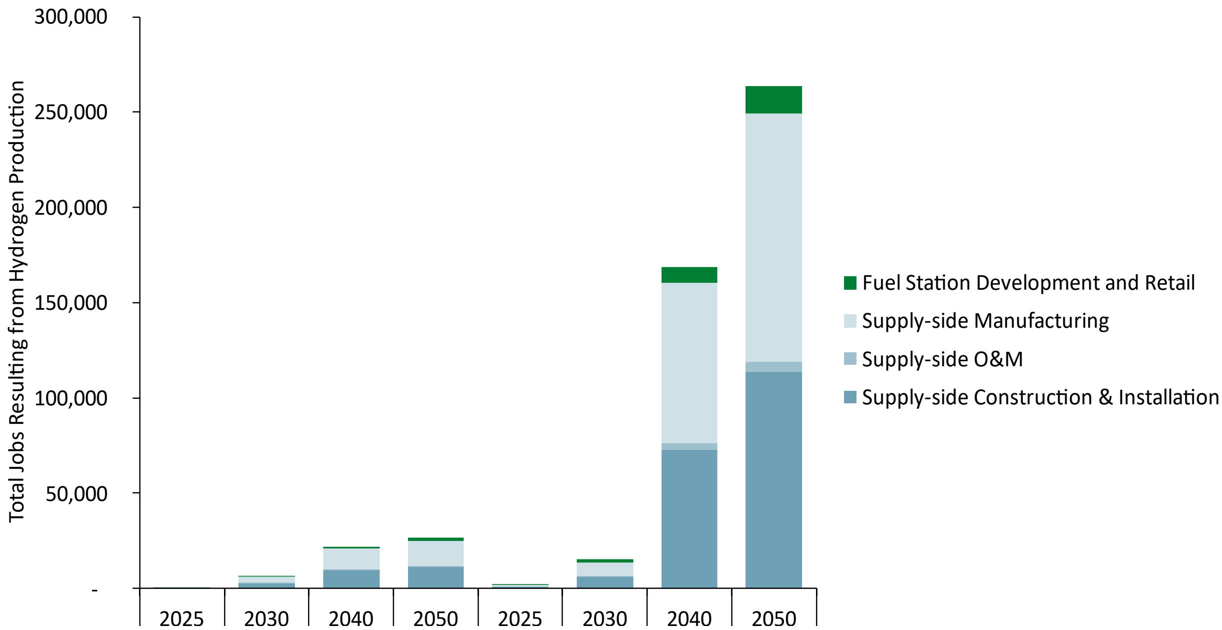


Figure 20. Potential impact of hydrogen supply chain on employment

4. Barriers and Challenges Related to Hydrogen Deployment

Although the production and consumption of hydrogen presents opportunities for the State of Colorado in a decarbonized future, significant barriers to the deployment of hydrogen still exist. These barriers are identified from existing literature studies and roadmaps as well as from conversations with stakeholders organized by E3 and the CEO organized the course of this project. E3 categorized these barriers into supply chain, market and technology, and policy barriers. Each of these issues are outlined in more detail below.

4.1. Supply chain

The lack of hydrogen storage and transportation infrastructure is arguably the largest obstacle to the widespread use of hydrogen. As discussed above, green hydrogen production will require seasonal storage due to the temporal mismatch between periods of greatest low-carbon electricity availability and periods of highest heat demand. Furthermore, optimal locations for producing hydrogen may not be nearby the main energy demand centers. This means that green hydrogen production will need to be paired with some means of storing hydrogen and transmitting it to consumers.

A mature, low-cost hydrogen transportation and storage system is likely to mirror the current gas infrastructure. The gas system consists of underground geological formations for storing natural gas under pressure, as well as pipelines for transmitting natural gas from production wells to storage and end uses. The current gas grid has a low blend limit of hydrogen that prevents more than approximately 7% hydrogen by energy from being blended in without the need for significant upgrades.[74]

Converting the existing gas network to carry 100% hydrogen will require pipeline materials compatibility checks and/or replacements of sections of the grid as well as gas compressor replacements. Existing end-use equipment that operates on natural gas (boilers, burners, appliances, industrial process equipment, etc.) would require burner retrofits or outright replacement.[75] Finally, existing gas storage reservoirs would have to be tested for hydrogen compatibility, which may require adaptations. A completely new hydrogen storage and transportation infrastructure could also be built rather than retrofitting the gas grid. In addition, to produce green or blue hydrogen, low-carbon hydrogen generation plants will need to be built. Large scale low-carbon hydrogen production plants do not currently exist in Colorado.

In order to spur hydrogen's use in the transportation sector, a new network of hydrogen fueling stations would be necessary. Constructing enough hydrogen stations to spur consumer vehicle adoption will initially result in low station utilization. This chicken-or-egg problem has been addressed in California via large amounts of station subsidies from the state and from automakers.[76]

Finally, a potential barrier related to the production of hydrogen mentioned by stakeholders throughout this project is the availability of water. Approximately four gallons of water are needed to produce one

[74] NREL (2013). Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues

[75] See: H21 Leeds City Gate Report: https://www.h21.green/wp-content/uploads/2019/01/H21-Leeds-City-Gate-Report.pdf

[76] See: https://www.energy.ca.gov/news/2020-12/energy-commission-approves-plan-invest-115-million-hydrogen-fueling

kilogram of hydrogen in the electrolysis process.[77] With this in mind, hydrogen development projects should take the site-specific availability of water into account, especially in water-stressed regions. Although the levels of water required may not pose a significant barrier in the state as a whole, water availability may pose challenges for hydrogen producers at the local level when researching and developing potential production sites. More research is required on this matter to assess the significance of this challenge in deploying a hydrogen economy.

4.2. Market and technology

E3 estimates that by 2050, the cost of producing, storing and delivering green hydrogen to a city gate in the Denver area may drop as low as $12/MMBTU when respectively produced via curtailed electricity and dedicated solar power. By contrast, natural gas is projected to remain under $6/MMBTU under a business as usual trajectory. To achieve cost competitiveness between hydrogen and incumbent fossil fuels in the transportation sector, fueling infrastructure costs per unit of delivered fuel would need to be minimized. Station costs are currently expensive due to their low utilization and the small size of stations. Transportation costs are high because there is not a pipeline network to deliver hydrogen to stations, and fuel must instead typically be trucked to stations. Finally, while there is recent interest for hydrogen in the energy and policy communities, consumer awareness and acceptance of hydrogen is lacking.[78] In order for hydrogen to be deployed at scale, efforts are required to help consumers understand the potential benefits of hydrogen, increase the availability of hydrogen-fueled vehicles on the market in Colorado, and eliminate concerns related to safety and reliability of hydrogen.

3.5. Policy

E3's literature research and conversations with stakeholders also indicate several policy-related barriers to the deployment of hydrogen. First, studies such as the U.S. Roadmap to a Hydrogen Economy show how a lack of market goals and targets are a hindering factor in kick-starting a hydrogen economy. Although Colorado has a ZEV mandate, more explicit guidance on the role of hydrogen would be beneficial for the growth of hydrogen in the region.

In addition, a lack of federal and state policies, codes, or standards that support hydrogen use serves as a barrier to the adoption of hydrogen in Colorado. Particularly concerning hydrogen blending and opportunities for storage, there is a need for standardization of codes related to safety metrics and material requirements (similar to Colorado's Retail Hydrogen Fueling Regulation). Harmonization of codes across states, for instance through FERC and the Pipeline and Hazardous Materials Safety Administration (PHMSA), could be beneficial in the medium term as other states adopt hydrogen goals and policies.

Colorado currently has few direct incentives and regulations in place to establish a viable FCEV market. While Colorado's participation in the ZEV mandate does incentivize OEMs to sell LDV FCEVs in Colorado,

[77] See: https://www.hydrogen.energy.gov/pdfs/review16/sa039_elgowainy_2016_o.pdf

[78] California Air Resources Board (2020). 2020 Annual Evaluation of Fuel Cell Electric Vehicle Deployment & Hydrogen Fuel Station Network Development

similar measures promoting or mandating the sale of FCEV MDVs and HDVs, such as the Advanced Clean Trucks standard, have not been enacted at this time.[79] The recently passed $5.3 billion Transportation Senate Bill 21-260 does however provide opportunities for the funding of hydrogen vehicles and refueling stations.[80] The Roadmap section (Chapter 5) provides additional policy recommendations that may help to develop a market for hydrogen in the next 10-15 year period.

[79] See: https://www.nescaum.org/documents/medium-and-heavy-duty-zero-emission-vehicles-action-plan-development-process/medium-and-heavy-duty-zero-emission-vehicles-action-plan-development-process#documents

[80] Colorado Senate Bill 21-260

5. Low-Carbon Hydrogen Roadmap

5.1. Key success factors for hydrogen deployment

The global deployment of low-carbon hydrogen is currently in early stages and many challenges exist in reaching more mature levels of production and demand, as outlined in Chapter 4. In order to overcome such barriers and incentivize the deployment of hydrogen, several recommendations, or key success factors, are commonly found throughout the literature. These success factors are noted in Table 4.

Table 4. Key success factors for the deployment of hydrogen commonly found throughout literature.

Key success factors for the deployment of hydrogen	Examples of studies that focus on or recommend key success factor
Supply chain	
Expanding the number of regions with hydrogen fuel stations.	• Japan (2019): Strategic Roadmap for Hydrogen and Fuel Cells • CARB (2020), Annual Evaluation of FCEV Deployment & Fuel Station Network Development
Boosting early demand industrial clusters with existing infrastructure to kick-start demand.	• Guidehouse (2020): European Hydrogen Backbone – How a Dedicated Hydrogen Infrastructure Can Be Created • Canada (2020): Hydrogen Strategy for Canada • NorthH2 project (Europe): kickstarting the hydrogen economy
Extend hydrogen infrastructure to support entire supply chain.	• CEC (2020): Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California
Market & Technology	
Realizing cost reductions through R&D projects and (inter)national cooperation.	• Japan (2019): Strategic Roadmap for Hydrogen and Fuel Cells • European Commission (2020): A Hydrogen Strategy for a Climate Neutral Europe • IEA (2019): The Future of Hydrogen: Seizing today's opportunities • Germany (2020): The National Hydrogen Strategy
Maintaining and building on current regional networks of technological start-ups, knowledge institutes and other	• Canada (2020): Hydrogen Strategy for Canada

Key success factors for the deployment of hydrogen	Examples of studies that focus on or recommend key success factor
businesses and organizations working on the advancement of hydrogen.	
Developing electricity rate structures specific to electric transmission-connected renewable fuel facilities, such as wholesale power market access and transmission charge.	• CEC (2020): Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California
Focusing on existing industrial applications and (heavy duty) transportation for early market deployment (most studies focus on these energy intensive sectors for short-term deployment of hydrogen rather than on more broader heat applications).	• European Commission (2020): A Hydrogen Strategy for a Climate Neutral Europe • Canada (2020): Hydrogen Strategy for Canada • California Fuel Cell Partnership (2019): The California Fuel Cell Revolution • McKinsey (2020): Roadmap to a U.S. Economy
Policy	
Establishing phased-in decarbonization and hydrogen goals.	• The Hydrogen Coalition (2020): Green Hydrogen Guidebook • McKinsey (2020): Roadmap to a U.S. Economy
Establishing hydrogen codes and safety standards through (inter)national cooperation.	• McKinsey (2020): Roadmap to a U.S. Economy • Canada (2020): Hydrogen Strategy for Canada • The Hydrogen Coalition (2020): Green Hydrogen Guidebook
Providing state and federal policy incentives related to market-based mechanisms.	• CARB (2020), Annual Evaluation of FCEV Deployment & Fuel Station Network Development • US DOE (2020): Hydrogen Strategy: Enabling a Low-Carbon Economy
Providing a strong investment agenda or open grant funding opportunities while building a clear pipeline of viable investment projects.	• CARB (2020), Annual Evaluation of FCEV Deployment & Fuel Station Network Development • European Commission (2020): A Hydrogen Strategy for a Climate Neutral Europe • Germany (2020): The National Hydrogen Strategy • Australia (2018): National Hydrogen Roadmap

5.2. Recommended actions

Based on the opportunities for hydrogen identified throughout this report, the existing barriers to deploying a hydrogen economy and key success factors found throughout literature, E3 identified a set of recommended actions for the State of Colorado in the next 15 years. Some of these actions are instrumental in kick-starting a hydrogen economy in the short term, while others depend on a variety of factors that are still uncertain today. These uncertainties include the cost trajectory of hydrogen versus other decarbonized fuels, the technical feasibility of pipeline blending, and the awareness and willingness of customers to adopt FCEVs over alternative vehicles. Because of these uncertainties, E3 recommends the State of Colorado to implement a "stage gate approach" in which the viability and desirability of certain actions are evaluated over time. This approach would require frequent monitoring of among others the costs of hydrogen compared to the costs of alternative fuels, land and water-use constraints and the success of pilot and demonstration programs.

Through conversations with state agencies in Colorado, a range of hydrogen experts and stakeholders, and E3's research into the state of the hydrogen market today, we recommend that Colorado pursue the near-term actions as outlined below.

Develop a Hydrogen Plan

As some of the barriers and key success factors investigated throughout this study show, the deployment of hydrogen would benefit from a set of clear mid-term actions as well as funding mechanisms to kickstart the development of hydrogen in early applications. E3 therefore recommends the State of Colorado develop a Hydrogen Plan that includes concrete actions for the deployment of low-carbon hydrogen, including an investment agenda and mid-term goals. For instance, specifically for the transportation sector, now that recent legislation in Colorado[81] has established funding opportunities through state enterprises for both hydrogen stations (the Community Enterprise) and vehicles (the Clean Fleet Enterprise), the plan could incorporate how this potential source of funding could be utilized in developing a hydrogen supply chain. E3 particularly recommends setting goals related to production of hydrogen and hydrogen infrastructure, potentially concentrated in a few centralized geographic areas or "hubs", with commitment from a few large demand centers, as described below.

The Colorado Hydrogen Plan can be informed by the scenario analysis performed for this Roadmap, particularly leveraging the results of the Growth and Transformative scenarios. These scenarios show that by 2030, demand for 45,000 metric tons of hydrogen could exist in a "Growth" scenario, mostly concentrated in the electricity sector and for hydrogen blended into the gas distribution system. In the Transformative scenario, up to 85,000 metric tons of hydrogen demand would exist, around 40% of which concentrated in the transportation sector, 30% in the power sector and 30% in remaining sectors. Assuming production would be supplied by green hydrogen, a production goal of between 45,000 – 85,000 metric tons of hydrogen would require capital investments ranging between $310-$650 million (lower end) and $590-$1,200 million (upper end), depending on electrolyzer cost trajectories.[82]

[81] SB 21-260 Sustainability of the Transportation System

[82] E3 estimates electrolyzer cost trajectories to decline to around 970 $/kW in a conservative scenario, and 525 $/kW in an optimistic scenario by 2030, from around 1,100 $/kW today

In developing a Hydrogen Plan, the state should consider using the results of this low-carbon hydrogen Roadmap, as well as lessons learned and best practices from the deployment of other alternative fuels in the state, such as CNG refueling stations.

Investigate regional hydrogen hubs

One of the largest current barriers to deploying hydrogen at scale the lack of available supply. Therefore, in order for a hydrogen supply chain to emerge, hydrogen production needs to scale. As demonstrated in European regions, kickstarting hydrogen production at a few centralized hubs near major demand centers, or "anchor tenants," where hydrogen consumption is cost-effective may provide an effective and low-risk approach. These anchor tenants could range from transportation centers to large facilities in the industry or power sector. As demonstrated throughout this report, E3 particularly identifies the MDV and HDV transportation segments as well as the power sector as promising sectors for near-term use of hydrogen because of the combination of cost-effectiveness, market readiness, and potential scale these segments provide. Early take-off of hydrogen in these segments could provide a boost to the hydrogen market that allows for a relatively small-scale starting point with significant expansion potential. In addition, the regional hydrogen hubs could make use of specific industrial applications with potential local hydrogen use cases, and may serve as a platform for pilots related to pipeline blending in the gas sector.

Drawn from other regional examples as well as from conversations with stakeholders, E3 recommends that the State of Colorado investigate the market interest and feasibility of regional early-deployment hydrogen hubs to demonstrate the use of hydrogen in mature or emerging applications, supported by recently passed legislation.[83] These hubs would involve hydrogen production, storage, and end-use at a relatively small scale with scaling potential, particularly leveraging a kick-start of hydrogen use in the applications mentioned above, potentially combined with the strategic use of hydrogen demand at local facilities. Examples of hydrogen hubs can be found in the Hydrogen Strategy for Canada and the NorthH2 project in Northern Europe, that (plan to) combine significant hydrogen production strategies with local large-scale end-use facilities, such as industrial clusters. In doing so, these hubs strategically make use of anchor tenants or early adopters in the market, while at the same time testing and demonstrating supply chain opportunities. In Colorado, the deployment of local hubs would allow the State of Colorado to test the hydrogen supply chain in a centralized setting, preparing for a mid- to long-term path where the potential of hydrogen can be expanded and scaled to achieve a more cost-competitive supply chain.

Although the exact location of the hydrogen hubs would need to be determined, E3 recommends investigating the areas in Colorado that combine good wind or solar resources, to support hydrogen production from renewable resources, with hydrogen transportation and storage opportunities, such as roads and existing pipeline infrastructure, and that are located within reasonable proximity of end-use opportunities and research institutes, such as the Denver Metropolitan Area, Colorado Springs, or Fort Collins.

[83] For example, the hydrogen hubs could make strategic use of the funding opportunities for hydrogen station presented in SB 21-260.

Develop pilot projects in the electricity generation sector

This Roadmap identifies significant opportunities for hydrogen use in the electricity generation sector, potentially replacing long-term peaking generation under stringent carbon targets making use of curtailed resources and long duration storage. The application of hydrogen in power generation requires research and development to demonstrate the effectiveness and potential technical constraints. These applications can be addressed through pilot projects, potentially in combination with local hydrogen hubs. E3 recommends utilities in Colorado develop pilot projects investigating the use of hydrogen in electricity generation to test hydrogen use in existing infrastructure. This could potentially make strategic use of retiring power generation assets, such as the Craig or Hayden plants, drawn from the Intermountain Power Project (IPP) example in Utah that is set to convert its existing coal plant into a green hydrogen production plant by 2025.[84] [85]

Develop pilot projects in the gas distribution sector

An important application mentioned throughout this study is the blending of hydrogen in the existing gas distribution system. To date, research shows that a maximum blending level of hydrogen in existing pipelines is estimated at 7% by energy content. However, few pilots on hydrogen blending have been performed, and E3 is not aware of regions where blending is already common at large-scale. Following the recently passed SB21-264 bill, E3 recommends gas utilities adopt pilot projects that test blending of hydrogen into the pipeline to reduce utility greenhouse gas emissions. SB 21-264, passed by the Colorado state legislature in June 2021, requires Gas Distribution Utilities (GDUs) to file a Clean Heat Plan with the public utilities commission (PUC), demonstrating how the GDU will use clean heat resources to meet the clean heat targets of 4% reduction in greenhouse gases by 2025 and 22% by 2030 compared to 2015 levels.[86]

Issue a Request for Information (RFI)

Throughout the development of this Roadmap, E3 has observed significant market interest for hydrogen in Colorado, as well as a large body of existing research institutes, network organizations, and technology providers, as outlined in Section 3.4.1. This existing network could be leveraged in the development of early-stage hydrogen hubs. To assess where hydrogen hubs could be strategically located, E3 recommends that the State of Colorado issue a Request for Information (RFI) to potential Colorado hydrogen market participants. This RFI would assess the feasibility of developing pilots and/or geographically-based hydrogen hubs in the state based on the interest and information received. Specifically, E3 recommends the RFI to gauge:

+ Interest from market parties in becoming involved in the development of hydrogen hubs;

[84] See: https://www.ipautah.com/ipp-renewed/

[85] It is important to note that pilot projects for regulated utilities are subject to PUC evaluation. For electric utilities, these will be likely be evaluatede as part of the Electric Resource Plan and Clean Energy Plan process; for gas utilities, these will likely be evaluated as part of the Clean Heat Plan process.

[86] The directions in the Clean Heat Plan are technology neutral, allowing for the use of energy efficiency, electrification, recovered methane and green hydrogen to meet a GDU's carbon reduction target.

+ Information on where potential hydrogen locations could exist;
+ The scale of potential production or demand offered by market parties;
+ The required funding for the development of (components of) a hub and level of co-funding available from private market participants;
+ How market participants propose to re-purpose or leverage existing infrastructure towards the use of hydrogen.

The RFI would be conducted as part of the process to establish regional hubs and would inform planning for hydrogen funding through enterprises established as a result of SB 21-260. The RFI could be established with input from DOE surveys and with the help of collaborators such as state graduate program capstone projects.

Other near- to mid-term recommendations

Other near- to mid-term actions recommended in this report, which would require the participation of non-government parties across Colorado, include:

- **Expand the refueling station network in Colorado.** Increasing the demand for hydrogen in the transportation sector will require a network of refueling stations that is similar in usage to gasoline stations. California's hydrogen support and research has shown that the adoption of 50,000 HFCV (passenger cars) requires at least 31 fueling stations.[87,88] With the recommended focus in this Roadmap on MDVs and HDVs, the ratio of necessary fuel stations per vehicle would be higher given the fuel economy and vehicle miles traveled (VMT) of these vehicles. E3 estimates that with approximately 4,000– 20,000 hydrogen-powered MDVs and HDVs on the road respectively in the Growth and Transformative scenarios in 2030, between 30 and 150 refueling stations would be required. Based on experience in California, E3 estimates the investment cost of developing these stations (including equipment and installation) between $66 million and $330 million.[89] However, the number of refueling stations required depends on multiple factors, including location, vehicle routes, and types of vehicles adopted. Therefore, additional research into the desired number and location of stations is required.
- **Develop codes & standards.** In cooperation with (inter)regional authorities, develop codes and standards for hydrogen transport and storage, for instance related to safety metrics, blending percentages and material requirements (similar to Colorado's Retail Hydrogen Fueling Regulation). As this need is shared across regions, interstate and national cooperation on such codes and standards is recommended.

[87] At a refueling capacity of 1,200 kg capacity/day.

[88] California Air Resources Board (2020). 2020 Annual Evaluation of Fuel Cell Electric Vehicle Deployment & Hydrogen Fuel Station Network Development 71 stations at an aggregated capacity of 36,730 kg/day.

[89] Based on $2.2 million per station, derived from the Joint Agency Staff Report on Assembly Bill 8: 2020 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California (2020 and 2016 version).

- **Increase vehicle availability & consumer awareness.** As mentioned by stakeholders throughout this project, the implementation of hydrogen in the transportation sector is partly hindered by the availability of vehicles in Colorado and lack of consumer awareness. Although the market is emerging, more focus on this segment of the market, for instance through cooperation with OEMs, could help eliminate the barriers related to FCEV adoption. The clean fleet enterprise established by SB 260 should consider what the appropriate levels of investment are in hydrogen trucks, and the state should consider whether regulatory steps such as adoption of and Advanced Clean Trucks standard would encourage greater availability.
- **Streamline permitting processes.** As mentioned by stakeholders, the acceleration of development projects, for instance for the development of refueling stations or production facilities, is often hindered by complex permitting processes at state or municipal level. To advance infrastructure development within the state, E3 recommends streamlining permitting processes that allow for accelerated construction. An example is California's electric vehicle charging station permit streamlining law (AB 1236 Statutes of 2015, Chapter 598), that establishes permitting processes and communication requirements for cities and counties to accelerate charging station development.

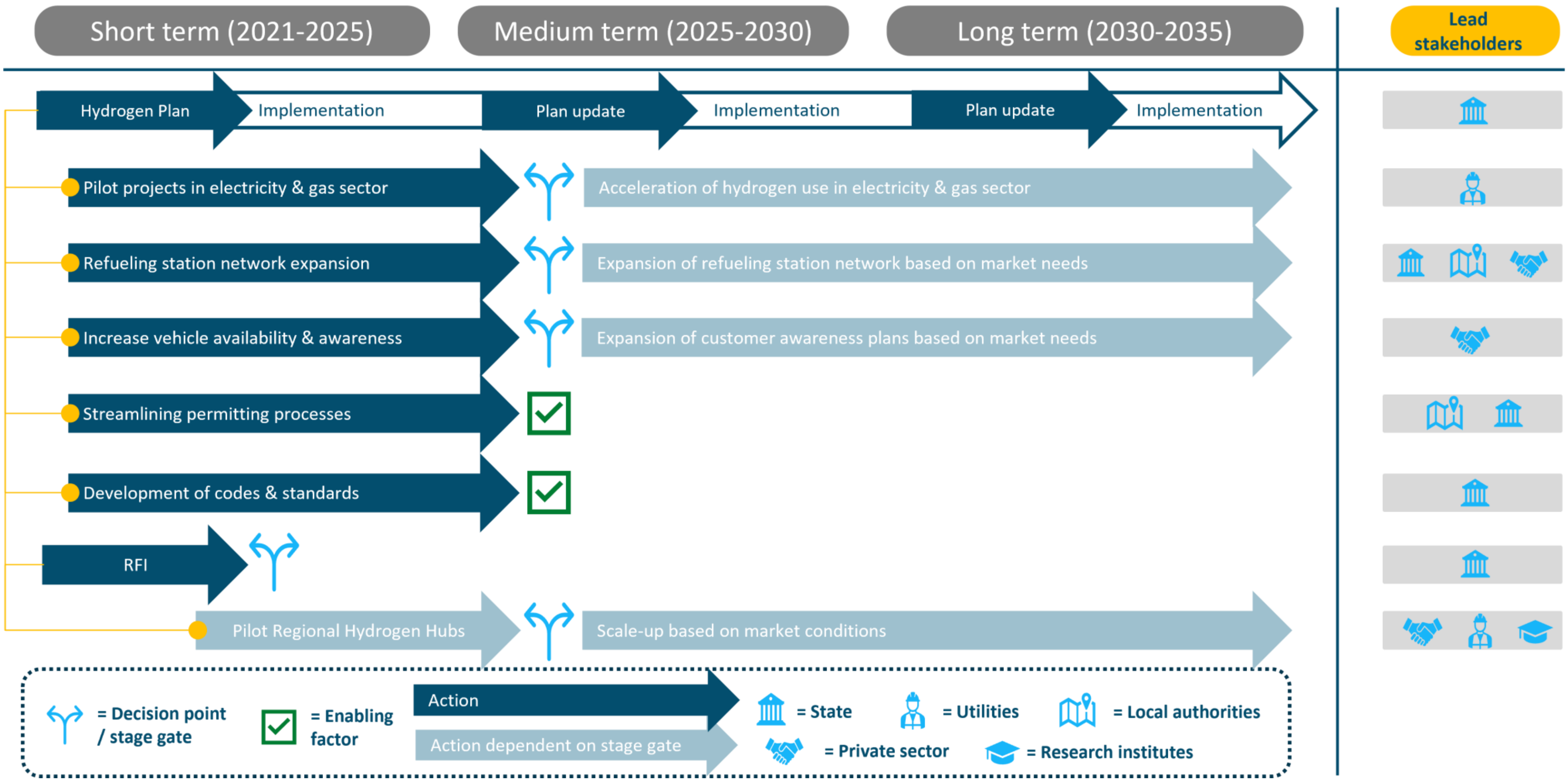
5.3. Roadmap & stakeholders involved

Figure translates the recommended actions to a visual Roadmap, indicating required actions on a short medium- and long-term timeframe. E3 recommends the State of Colorado kick-off the development of a Hydrogen Plan and issuance of a Request for Information as immediate next steps. The Hydrogen Plan would include concrete actions for the state and other stakeholders commit to on a short- to medium-term basis, including an investment agenda, concrete hydrogen goals, pilot projects, and plans regarding the expansion of a hydrogen refueling station network. The RFI would provide a basis for the development of regional hydrogen hubs as described in the previous section.

Given uncertainty in the hydrogen market and the continuous evaluation of market conditions and needs, Figure includes a set of "stage gates" in the 2025 – 2030 timeframe. These stage gates represent decision points for the state and other stakeholders to define next steps based on an evaluation of progress, market needs and market conditions. E3 recommends the State of Colorado regularly update the Hydrogen Plan to account for these uncertainties, evaluating progress made over the past years and responding to market needs.

The recommended actions provided in this Roadmap require involvement from a variety of stakeholders. While policy related actions naturally involve a role for state agencies and local authorities, the actions related to supply chain and market require the involvement of market players, research institutes, utilities and technology providers, leveraging the existing landscape in Colorado as described in Section 3.4. Figure provides an indication of the lead stakeholders involved per recommended action.

Figure 22. Roadmap to accelerated hydrogen deployment in Colorado



6. Appendix

Appendix A: Definitions of low-carbon hydrogen

At present, standardized and consistent definitions of hydrogen have not yet been established. Definitions used in literature differ from defining hydrogen by production source (often referred to by colors), or by level of emissions (ranging from "fossil-based", to "low-carbon" and "renewable"). Several common definitions are found throughout the literature that can be classified as follows:

- **Fossil-based hydrogen without carbon capture and sequestration (CCS):** All hydrogen produced through fossil fuels without application of CCS. Within this category, "grey" and "brown" hydrogen can be distinguished.
  - ***Grey hydrogen***: Hydrogen produced from hydrocarbons, the most common being steam methane reformation (SMR) without (CCS). This is the most common source of hydrogen today for consumption in refineries and the ammonia industry, accounting for around 75% of global production.[90]
  - ***Brown hydrogen:*** Hydrogen produced from coal and water through gasification. Brown hydrogen is currently the second most common source of hydrogen production due to its dominant role in China.
- **Fossil-based hydrogen with CCS:** All hydrogen produced through fossil fuels with application of CCS. The most common form is referred to as "blue" hydrogen, though hydrogen produced through gasification with CCS would also fall within this category.
  - ***Blue hydrogen***: Hydrogen produced from hydrocarbons with CCS, such as from steam methane reformation (SMR).
- **Electricity-based hydrogen:** all hydrogen produced through electrolysis, regardless of the electricity source. Common definitions that specify the type of electricity used are "green" or "pink" hydrogen.
  - ***Green hydrogen***: Hydrogen produced from water by electrolysis using renewable electricity such as hydroelectricity, wind, or solar resources.
  - ***Nuclear or 'pink' hydrogen:*** Hydrogen produced from water by low- or high-temperature electrolysis from nuclear energy.
- **Renewable hydrogen**: encompasses all hydrogen produced through renewable electricity ("green" hydrogen) or hydrogen produced from biomass and waste through gasification.
- **Low-carbon hydrogen**: encompasses both fossil-based hydrogen with CCS and electricity-based hydrogen, with significantly reduced life-cycle greenhouse gas emissions compared to existing

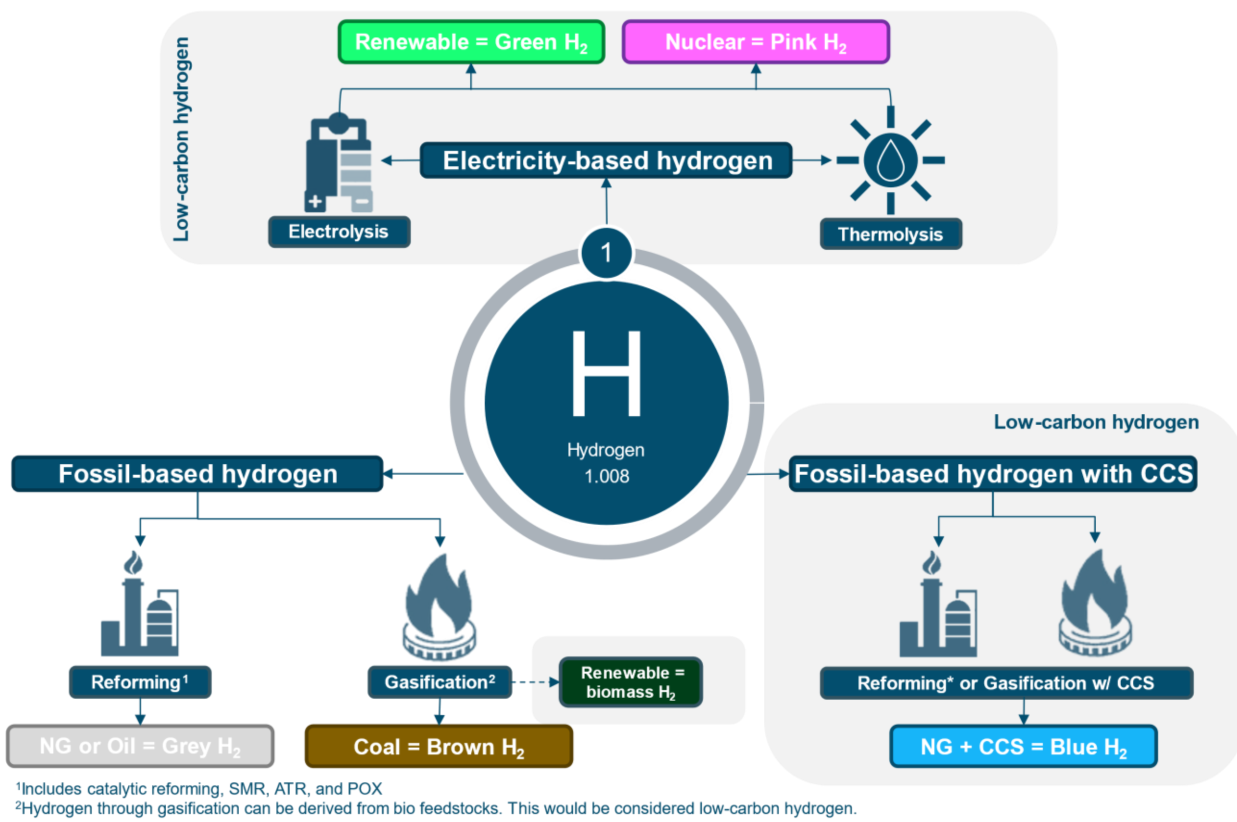
[90] IEA (2019). The Future of Hydrogen.

hydrogen production. This definition would include all of the definitions above, with the exception of fossil-based hydrogen.

In addition to the production methods and definitions described, different types of hydrogen in end-use applications can be distinguished ranging from the use of hydrogen in pure form (H_2) to the use of hydrogen to produce synthetic fuels, such as Synthetic Natural Gas (CH_4), produced by a combination of hydrogen and a climate-neutral source of CO_2. An overview of these different uses in end-use applications can be found in Section 4 (Opportunities for hydrogen in Colorado).

Figure provides a graphic illustration of the definitions of hydrogen. The types of hydrogen considered as “low-carbon hydrogen” are boxed in grey.

Figure 23. Illustration of hydrogen definitions



Appendix B: Input assumptions

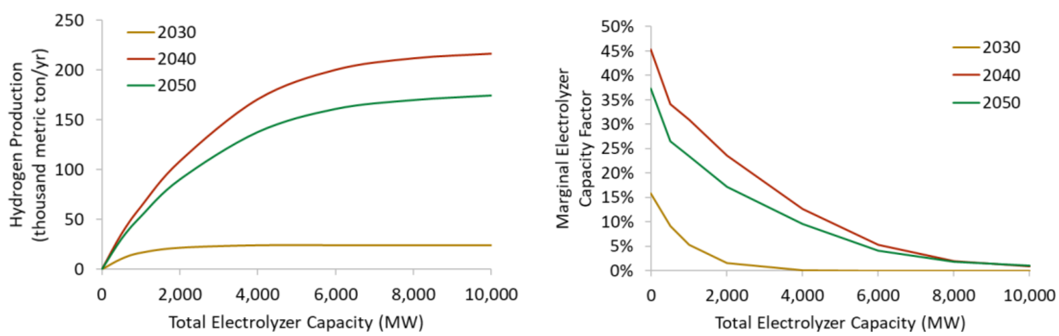
Hydrogen cost estimates

In Figure 8, hydrogen costs assuming production from SMR with CCS are estimated from the NREL H2A model with natural gas prices from the US Energy Information Administration (EIA).[91, 92] For renewable hydrogen production, two cost scenarios were evaluated assuming conservative or optimistic electrolyzer costs and efficiencies, respectively, with the assumptions developed by UC Irvine for the CEC study, *The Challenge of Retail Gas in California's Low-Carbon Future*.[33] Solar and wind capacity factors are assumed to be 28% and 48%, respectively, for Colorado and salt cavern costs are based on the NREL H2A model.

Hydrogen production from curtailed renewable energy

Hydrogen production from curtailment as a function of total electrolyzer capacity is shown in the left of Figure . Hydrogen production slows down and eventually plateaus as more electrolyzer capacity is added. This can be further seen in the right of the figure. As more electrolyzer capacity is available to absorb surplus renewables, less curtailment remains for charging newly added electrolyzers, resulting in declining marginal capacity factors.

Figure 4. Left: Annual hydrogen production from curtailed renewable energy. Right: Marginal capacity factor of electrolyzer (charging only, using curtailed renewables)



[91] H2A: Hydrogen Analysis Production Model Archives: Future Central Hydrogen Production from Natural Gas with CO_2 Sequestration version 3.101. National Renewable Energy Laboratory. https://www.nrel.gov/hydrogen/assets/docs/future-central-natural-gas-with-co2-sequestration-v3-101.xlsm

[92] Delivered natural gas prices from: US EIA Annual Energy Outlook 2021. Table 62. Natural Gas Delivered Prices by End-Use Sector and Census Division. Prices used for SMR/CCS hydrogen cost calculations are adjusted for the industry sector in Colorado using historical prices from: US EIA Natural Gas Monthly (data for March 2021).

Hydrogen end use assumptions

Assumptions used to estimate operating cost comparisons within the building and transportation sector under traditional fossil based and zero-carbon fuels and technology:

Table 0-1: Transportation Operational Cost Comparison Assumption Sources

Vehicle Type	Engine	Fuel Economy	Fuel Price	Cargo (Tons)
LDV Passenger	ICE	EPA fuel rating for Honda CR-V	Average pump price of gasoline in CO today	N/A
	BEV	EPA fuel rating for Tesla Model Y	Average residential electric rate in CO today	N/A
	HFCV	EPA fuel rating for Hyundai Nexo	E3 estimate – pump price from off-grid solar hydrogen production	N/A
LDV Pickup	ICE	EPA fuel rating for Ford F-150	Average pump price of gasoline in CO today	N/A
	BEV	CO GHG Pollution Reduction Roadmap	Average residential electric rate in CO today	N/A
	HFCV	CO GHG Pollution Reduction Roadmap	E3 estimate – pump price from off-grid solar hydrogen production	N/A
MDV - Bus	ICE	Manufacturer reported	Average pump price of gasoline in CO today	N/A
	BEV	Manufacturer reported	Commercial off-peak EV charging	N/A
	HFCV	Assumed same as BEV	E3 estimate – pump price from off-grid solar hydrogen production	N/A
MDV - Truck	ICE	Manufacturer reported / CO GHG Pollution Reduction Roadmap	Average pump price of gasoline in CO today	7
	BEV	CO GHG Pollution Reduction Roadmap	Tesla supercharging station	3
	HFCV	CO GHG Pollution Reduction Roadmap	E3 estimate – pump price from off-grid solar hydrogen production	7
HDV	ICE	CO GHG Pollution Reduction Roadmap	Average pump price of gasoline in CO today	29
	BEV	Tesla Semi	Tesla supercharging station	18
	HFCV	CO GHG Pollution Reduction Roadmap	E3 estimate – pump price from off-grid solar hydrogen production	30

Table 0-2: Building Operational Cost Comparison Assumption Sources

Fuel Type	Device Efficiency	Fuel Cost
Natural Gas Furnace	0.85	Average residential natural gas rate in CO today
Heat Pump	2.90	Average residential electric rate in CO today
Hydrogen Boiler	0.90	E3 estimate – off-grid solar hydrogen production
SNG Furnace	0.85	E3 estimate – off-grid wind SNG production

Hydrogen demand assumptions by scenario and end use

Assumptions used to estimate hydrogen demand in each sector under the three scenarios:

Table 0-3: Scenario assumptions

Subsector	HB 1261 scenario	Growth scenario	Transformative scenario
Transportation Sector			
LDVs	Consistent with HB 1261 (no H_2)	Consistent with HB 1261 (no H_2)	50,000 FCEV in 2030, 1 million by 2050
MDVs	Consistent with HB 1261 (no H_2)	2,500 FCEV in 2030, 15,000 by 2050	12,000 FCEV in 2030, 80,000 by 2050
HDVs	Consistent with HB 1261 (no H_2)	1,500 FCEV in 2030, 10,000 by 2050	8,000 FCEV in 2030, 50,000 by 2050
Buses	Consistent with HB 1261 (no H_2)	200 FCEV in 2030, 1,500 by 2050	1,000 FCEV in 2030, 7,000 by 2050
Buildings Sector			
Residential	Consistent with HB 1261 (5% pipeline blend by 2050)	H_2 serves 7% of pipeline demand by 2050	H_2 serves as peak heat back-up in buildings (through Synthetic Natural Gas)
Commercial	Consistent with HB 1261 (5% pipeline blend by 2050)	H_2 serves 7% of pipeline demand by 2050	H_2 serves as peak heat back-up in buildings (through Synthetic Natural Gas)

Industry			
Manufacturing	Consistent with HB 1261 (no hydrogen demand)	H_2 serves 7% of pipeline demand by 2050	H_2 serves 23% of final demand by 2050
Oil & Gas	Consistent with HB 1261 (no hydrogen demand)	Consistent with HB 1261 (no hydrogen demand)	Consistent with HB 1261 (no hydrogen demand)
Power sector			
Peaking & Long-duration storage	Consistent with HB 1261 (no hydrogen demand)	H_2 replaces up to 7% of natural gas generation by 2050	Demand supplied by production from curtailed renewables through 2040; H_2 replaces up to 100% of natural gas generation by 2050