
# RENEWABLE HYDROGEN IN OREGON: Opportunities and Challenges

Submitted to the
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by the
**OREGON DEPARTMENT OF ENERGY**

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This report has been prepared by the Oregon Department of Energy for submission to the Oregon Legislature consistent with the requirements of Senate Bill 333 (2021). ODOE's objective with this study was to study and synthesize the opportunities and challenges associated with the production and consumption of renewable hydrogen in Oregon to inform the State Legislature and other interested parties.

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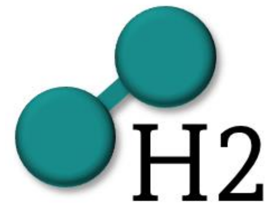
*Annelise Downey drives the Anteater Express, a zero emission Hydrogen Fuel Cell bus to a hydrogen fueling station in Irvine, CA to fill the bus.*

## EXECUTIVE SUMMARY




There is unprecedented interest in hydrogen today for its potential to address climate change. This report presents the findings of the Oregon Department of Energy's study on renewable hydrogen – what it is, how it's made, what it might cost, and where it might best fit within the vision for a decarbonized economy in Oregon and the Pacific Northwest.

Hydrogen is a global commodity, and is primarily used for oil refining, production of ammonia and methanol, and steel production. Most of the hydrogen used today is produced using fossil fuels, mostly natural gas and coal. About 94 million tons of hydrogen were produced globally in 2021, resulting in emissions of more than 900 million metric tons of CO2, or about the same amount of emissions as worldwide commercial aviation in 2019.[1] [2]

Renewable hydrogen can be produced using renewable electricity to split water into hydrogen gas and oxygen gas using an electrolyzer. Some definitions of renewable hydrogen include hydrogen produced from biomass or biogas feedstocks via gasification or pyrolysis, though these pathways are not necessarily carbon-free. The U.S. Department of Energy has launched a program called Hydrogen Shot, which focuses on "clean" hydrogen – low-carbon hydrogen produced by using renewable resources or from fossil resources paired with carbon capture.

### Benefits Associated with Renewable Hydrogen

**Immediate GHG emissions reductions for swapping.** Renewable hydrogen can be swapped in for fossil hydrogen wherever it is currently used with no need for retrofits.

**Solution for hard-to-abate sectors.** For some use cases, electrification may not be feasible and there aren't many other existing sustainable fuel options. For these use cases, like high-temperature industrial processes, heavy-duty transportation, fertilizer production, marine vessels, and aviation, renewable hydrogen can provide a necessary pathway for decarbonization.

**Support grid reliability.** Renewable hydrogen production via electrolysis can provide greater reliability to the electric grid and support the addition of more variable renewable resources by acting as a flexible load – one that can be used when it is needed to meet demand.

**Provide resiliency.** Renewable hydrogen can serve as a medium for long-duration energy storage and as a back-up generation fuel to replace diesel generators.

### Opportunities in Oregon for Renewable Hydrogen

Interest in production and use of renewable hydrogen in Oregon is growing, due in no small part to the region's plentiful renewable electricity resources, the billions of dollars in new federal grants and tax credits available, and state and regional climate and clean energy goals. Potential renewable hydrogen projects have been proposed across the state, namely along the I-5 corridor, the coast, and along the Columbia River/I-84 corridor.

There are a number of ways that renewable hydrogen could be used in Oregon, some more cost-effective or with more CO2 emissions reduction potential than others. To some extent, the market will determine where and how renewable hydrogen is used in Oregon, but decision-makers should consider the following when deciding if and how to provide policy support for specific end uses:

**Properties of hydrogen.** Hydrogen is very energy dense by weight, but not by volume, so it must be compressed or liquified for transport and many use cases.
**Production efficiencies.** As with all other energy carriers, there are efficiency losses associated with the production, compression or liquefaction, storage, and transport of hydrogen. For example, using electricity for building heating and cooling is more efficient than using electricity to produce hydrogen to then use as a fuel for buildings.
**GHG emissions reductions.** GHG emissions reductions for end use options can vary widely.
**Costs and availability of substitutes.** Renewable hydrogen must compete with both the incumbent fuel and all other decarbonization options in each use case. Currently, renewable hydrogen is relatively expensive, but with recent federal legislation and technological advances, renewable hydrogen could hit cost parity with fossil hydrogen by about 2025.

This study finds that the likeliest end uses for renewable hydrogen in Oregon by 2030 will be, in relative order of value, as a substitute for fossil hydrogen, to create high-temperature heat for industry, medium- and heavy-duty transportation, production of chemicals (including fertilizer), energy storage, back-up power, electricity generation, and blending into the natural gas pipeline.

### Barriers to Adoption of Renewable Hydrogen and Recommendations

For renewable hydrogen to become an affordable, available resource – to be fully commercialized – there are several barriers to address. These include:

**High costs and low efficiencies.** Renewable hydrogen is more expensive than fossil hydrogen and some other decarbonization options, due in part to efficiency losses. However, federal funding and technological advances are helping to address both issues.
**Chicken-and-egg problem.** To create a market for renewable hydrogen, production and end use solutions for it must develop at about the same time.
**Lack of infrastructure.** There is no existing hydrogen infrastructure in Oregon.
**Safety.** Oregon safety and building codes will need to be updated to ensure that production, transportation, storage, and use of hydrogen is done safely.
**Water consumption.** Producing renewable hydrogen via electrolysis requires water, though recycled water may be used in place of freshwater.
**GHG implications of leakage.** Hydrogen is an indirect greenhouse gas and recent studies suggest that the climate benefits of using renewable hydrogen to replace fossil fuels will depend, in part, on ensuring that leaks are mitigated to the maximum extent possible.

To strategically take advantage of renewable hydrogen to meet the state's clean energy and climate goals, ODOE recommends development of a renewable hydrogen roadmap as part of a larger state energy strategy formation.

This report is available online: [www.oregon.gov/energy/energy-oregon/Pages/rh2.aspx](www.oregon.gov/energy/energy-oregon/Pages/rh2.aspx)

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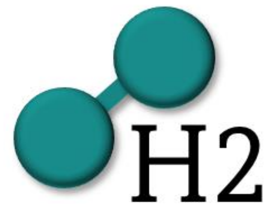


The energy system across the U.S. is evolving to address the increasing adoption of state decarbonization goals. While electrification can replace some or all of the fossil fuels currently used in sectors like buildings (heating), transportation, and industrial (some applications), other sectors are more challenging to decarbonize. For these hard-to-abate end uses – steel, cement, heavy industry, and heavy-duty transportation are examples – hydrogen can serve as a replacement for fossil fuels. However, the ability of hydrogen to reduce greenhouse gas (GHG) emissions depends on how the hydrogen is produced. Hydrogen produced from renewable feedstocks is considered "renewable" hydrogen, and its use in place of fossil fuels can greatly reduce the carbon intensity of many economic sectors. Hydrogen produced using feedstocks not considered renewable (i.e., natural gas, nuclear power, etc.) but where the GHG emissions are relatively low or captured is referred to as "clean" hydrogen.

The U.S. Department of Energy (US DOE) launched its Hydrogen Shot program in June 2021, which has a goal of reducing the cost of clean hydrogen to one dollar per one kilogram in one decade ("1 1 1") and includes support for numerous research and development initiatives. In Oregon, the state legislature passed SB 333 in 2021, which required the Oregon Department of Energy (ODOE) to study renewable hydrogen and is the basis of this report.

## Study Background

SB 333 directed ODOE to study the benefits and challenges associated with the production and consumption of renewable hydrogen in Oregon. Specifically, ODOE was directed to study and report back to the legislature with:

- Identification of the total hydrogen volume currently used annually in Oregon among industries such as technology, manufacturing, medical, and chemical;
- Identification of the potential applications in Oregon by 2030 of renewable hydrogen in transportation, industry, electricity generation, medical, and chemical;
- An assessment of the potential for coupling renewable electricity generation and renewable hydrogen production to increase resiliency or provide flexible loads;
- A discussion of the forecasted costs of renewable hydrogen and how these costs might affect the adoption of renewable hydrogen in Oregon; and
- Identification of the technological, policy, commercial, and economic barriers to adoption of renewable hydrogen in Oregon.

## Study Process

### *Technical Advisory Committee*

The Department determined that given the breadth and depth of hydrogen expertise in the region, the study would benefit from a Technical Advisory Committee (TAC) to provide insights and feedback on data sources, study assumptions, and study findings. Due to the growing interest in hydrogen in the region and the range of views and economic interests related to its role in Oregon's energy economy, ODOE chose to limit the TAC to technical experts from the public sector, non-profits, and academia who would, to the greatest extent possible, be able to provide unbiased technical expertise and guidance. The TAC was comprised of the following members:

**Jillian DiMedio**, Oregon Dept. of Transportation
**Chris Hagen**, Oregon State University
**Hal Nelson**, Portland State University
**Zhenxing Feng**, Oregon State University
**Jamie Holladay**, Pacific Northwest National Lab
**Steven Simmons**, Northwest Power and Conservation Council

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ODOE reached out to TAC members individually for guidance and feedback during the finalization of the study scope and during the research phase of the study. The Department convened the TAC for a meeting on June 13, 2022 to solicit feedback on initial study findings and all TAC members were later requested to provide peer review of the final study report.

### *Stakeholder Engagement*

Throughout the course of the study, ODOE strove to conduct inclusive outreach and engagement with Tribes, state agencies, environmental organizations, Oregon utilities, project developers, environmental and equity advocates, and others.

The Department reached out to each of the nine federally recognized Tribes in Oregon to discuss the study. Additionally, ODOE used its newsletter distribution list, blog, and social media channels to share information on the study and public workshops. Ongoing notifications and information were shared via email communications to the study distribution list, the Department's study webpage, and through two public meetings. The study webpage included a sign-up feature that allowed anyone from the public to add their name or the entity they represented to the study distribution list.

ODOE held two public workshops related to the study. The first provided stakeholders with details on the proposed study scope and timeline, including a brief primer on hydrogen and renewable hydrogen, and solicited feedback from attendees on the study as proposed. The second workshop provided a walk-through of the initial study findings and again allowed for stakeholders to provide feedback. These meetings were recorded and placed online and ODOE provided the opportunity for written or verbal follow-up comments after each workshop.

- November 16, 2021: **Stakeholder Workshop #1**
    - Full video recording, agenda, and presentation materials available online
- July 6, 2022: **Stakeholder Workshop #2**
    - Full video recording, agenda, and presentation materials available online

### *Hydrogen Consumption Inventory*

To determine the annual consumption of hydrogen in Oregon, ODOE first conducted research to identify the economic sectors with the most common end uses for hydrogen today. The Department then researched how many companies in these economic sectors were located in Oregon and began outreach to determine whether these companies use hydrogen in their Oregon-based business processes. ODOE reached out to companies via both email and phone and each company was contacted a minimum of three times.

Few of the companies responded to ODOE's outreach and of those that did, even fewer were willing to share details about their hydrogen consumption. Many companies cited confidentiality concerns as they considered this data to be competitive intelligence.

# CHAPTER 2: HYDROGEN PRODUCTION PATHWAYS AND CARBON INTENSITIES

## What is Hydrogen?

Hydrogen is the lightest and most abundant element in the universe and can exist as a gas or, when supercooled, a liquid. On Earth, hydrogen as an element is found in the greatest quantities within water molecules. It is present as a gas in the atmosphere only in tiny amounts – less than 1 part per million by volume. Any hydrogen that does enter the atmosphere quickly escapes the Earth's gravity into outer space.

**Hydrogen is considered an energy carrier, not an energy source, because it does not exist freely in nature and must be produced using other sources of energy.**

Hydrogen is considered an energy carrier, not an energy source, because it does not exist freely in nature and must be produced using other sources of energy.[3] The Earth has a wide variety of energy sources that can be harvested to produce an even wider variety of energy carriers. Some energy sources, such as fossil fuels, are also energy carriers. That is, their energy can be transported to and used by energy consumers in the same form as it is found. Other energy sources, such as falling water and solar radiation, must first be converted to an energy currency (usually electricity) before the energy can be used.

| ENERGY SOURCES | ENERGY CARRIERS |
|---|---|
| • Fossil fuels<br>• Solar radiation<br>• Nuclear<br>• Wind<br>• Biomass<br>• Falling water | • Fossil fuels<br>• Electricity<br>• Hydrogen<br>• Mechanical work<br>• Heat |

Globally, hydrogen is predominantly used for industrial applications, such as oil refining (33 percent), ammonia production (27 percent), methanol production (11 percent), and steel production (3 percent).[4]

## Hydrogen Production Pathways

Nearly all of the hydrogen present on Earth is found in compounds, like water or fossil fuels, and energy is required to separate, or extract, hydrogen from these compounds. The most common pathway for production of hydrogen in use today is steam reforming using natural gas, though other pathways, including electrolysis, are gaining in use.

### *Steam-Methane Reforming*

Steam-methane reforming (SMR) is a high-heat process that has been used for decades to produce hydrogen. Natural gas and steam are "reformed" into carbon monoxide, carbon dioxide, and hydrogen through a multi-step, catalytic process.[5] SMR is one of the most cost-effective processes for producing hydrogen, but also one of the most carbon intensive – Argonne National Laboratory updated the SMR pathway in its GREET[i] model to a median figure of 9 kg of CO2 per kg of hydrogen based on recent

[i] The Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model, or GREET, is a widely used lifecycle emissions tool maintained by the U.S. Department of Energy.

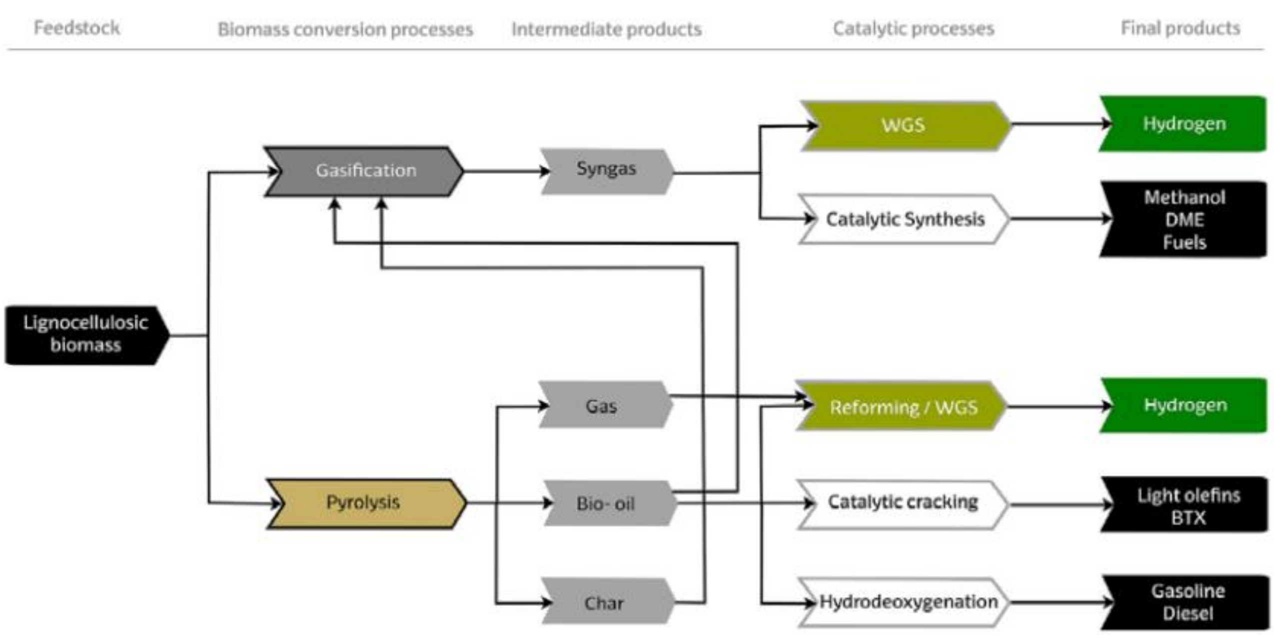
analyses.[6] For reference, the 2021 Infrastructure Investment and Jobs Act defines "clean" hydrogen as having a carbon intensity (at the site of production) of less than 2 kg of CO2 per kg of hydrogen.[7] Greenhouse gas (GHG) emissions associated with SMR can be reduced when biomethane (renewable natural gas) is used or when it is paired with carbon capture and storage (CCS). When deployed with the production of hydrogen via SMR, CCS can have a CO2 capture rate of between 53 and 90 percent.[8] However, as of 2021, only about one percent of hydrogen produced from fossil fuels was paired with CCS.[9]

### *Biomass-to-Hydrogen Pathways*

Pathways to produce hydrogen from biomass can be categorized as thermochemical or biological. Thermochemical processes include gasification and pyrolysis, which have better overall efficiency of converting thermal energy into hydrogen production than biological pathways, and are better established and lower cost.[10] In 2015, the Oregon legislature passed a bill (SB 752) that essentially treats biomass as carbon neutral in that most of the state's air pollution laws do not apply to CO2 emissions associated with the combustion or decomposition of biomass.

Biomass gasification is a process where biomass is converted into gas using a gasification agent such as oxygen or carbon dioxide. There are numerous processes for this that differ based on the gasification agent used, the method of supplying heat, and other factors. Gasification pathways for hydrogen production must include a step to clean, or purify, the initial gas, which is a mixture of hydrogen, carbon monoxide, and CO2. Biomass pyrolysis is the gasification of biomass in the absence of oxygen.[11] Figure 1 shows a schematic for each of these pathways using lignocellulosic (plant matter) biomass.

**Figure 1: Representation of the Main Processes Involved in Producing Hydrogen from Lignocellulosic Biomass Using Gasification and Pyrolysis[12]**




A number of biological pathways for producing hydrogen from biomass are in the research phase, including using microorganisms like microalgae for fermentation or photolysis, which refers to splitting water into hydrogen and oxygen using the absorption of light to power the process instead of electricity. Widescale deployment of these hydrogen production pathways are not anticipated in the near term.[13]

### *Hydrogen via Electrolysis*

Hydrogen produced via electrolysis is an established pathway that has been in use at a commercial scale since around 1890. Electrolysis is an electrochemical process where electricity is used to split water into hydrogen and oxygen. An electrolyzer is composed of an anode and a cathode separated by an electrolyte; an electrolyte, simply put, is the chemical from which ions are made. The ions created in the electrolyzer effectively pull water molecules apart, which can be converted, with help from electricity, into hydrogen and oxygen. Electrolyzers are increasingly being produced as modules that can be used singly for small needs or combined for installations with hundreds of megawatts (MW) of capacity.

**Electrolysis is an electrochemical process where electricity is used to split water into hydrogen and oxygen.**

Around one quart of water is needed to produce one kg of H2.[4] Given concerns in many locales over the supply of fresh water, electrolyzers can use recycled water from wastewater treatment plants or desalinated seawater.

There are four main electrolyzer technologies: alkaline electrolysis (ALK), proton exchange membrane (PEM) electrolysis, solid oxide electrolysis cells (SOEC), and anion exchange membranes (AEMs). These technologies vary not only in the electrolyte used and the types of ions created, but also in operational characteristics like temperature, pressure, and efficiency. According to the International Renewable Energy Agency, "each technology has its own challenges… there is no clear winner across all applications, which leaves the door open for competition and innovation…"[14]

Alkaline, or ALK, electrolyzers are the most mature of the four technologies, relatively low cost because they don't require precious metals, and have high hydrogen generating capacities.[15] As such, they make up most of installed electrolyzer capacity – 61 percent globally as of 2020.[16] They typically use a potassium hydroxide solution as the electrolyte, operate at moderate temperatures (i.e., below 100 degrees Celsius or 212 degrees Fahrenheit), and have relatively high efficiency. However, ALK electrolyzers operate at a relatively low current density, which limits how small the units can be, and they have high maintenance requirements.

Proton exchange membrane electrolyzers were developed in the 1960s to overcome some of the limitations of ALK units, and modern PEM units include advantages such as high current densities (allowing faster hydrogen production), lower maintenance needs, the ability to operate at a range of different pressures, and fast response times to changes in current, which is valuable for integrating variable renewable electricity generating resources.[15] [17] However, PEMs do require precious metals, which makes the units more expensive than ALKs. As of 2020, 31 percent of electrolyzers deployed globally were PEM; however more PEM electrolyzer capacity was added than ALK each year from 2018-2020.[16]

Compared to ALK and PEM technology, solid oxide electrolysis cells, or SOECs, and anion exchange membranes, often called AEMs, are not as commercialized. SOECs operate at high temperatures, which allows the use of fairly cheap nickel electrodes, reduces the overall electricity demand since heat can be used to drive part of the process, and provides the highest potential efficiencies in of the four electrolyzer technologies.[18] However, these electrolyzers can suffer from shorter lifetimes due to degradation from thermo-chemical cycling, which makes these units less ideal for pairing with variable renewable electricity.[14] AEM electrolyzers are the least mature technology, with limited deployment. AEMs provide some of the benefits of both ALK and PEM electrolyzer designs, but current iterations have stability, performance, and lifespan issues.[14]

## Categorizing Hydrogen Production Based on Environmental Impact

In recent years, hydrogen production has been categorized using colors to denote the feedstock and, in some cases, elements of the production process. The color gray is used to describe hydrogen made from fossil fuels while blue hydrogen refers to hydrogen produced with fossil fuels where carbon capture and storage (CCS) is used to reduce carbon emissions. Green is most commonly used to denote hydrogen produced from renewable electricity via electrolysis, but some use green to also refer to hydrogen produced from biomass or biogas. "Green" and "renewable" hydrogen are sometimes used interchangeably.

**Figure 2: Categorization of Hydrogen According to Color[19]**

| Color | Primary Feedstock | Primary Energy Source | Primary Production Process | Carbon Intensity $kgCO_2e/kgH_2$ |
|---|---|---|---|---|
| Brown | Coal or Lignite | Chemical Energy in Feedstock | Gasification & Reformation | |
| Gray | Natural Gas | Chemical Energy in Feedstock | Gasification & Reformation | |
| Blue | Coal, Lignite, or Natural Gas | Chemical Energy in Feedstock | Gasification with Carbon Capture and Sequestration | |
| Pink | Water | Nuclear Power | Electrolysis | |
| Green | Water | Renewable Electricity | Electrolysis | |
| Green | Biomass or Biogas | Chemical Energy in Feedstock | Gasification, Reformation, & Thermal Conversion | |

While color can give some idea of the environmental impact associated with the production of hydrogen, it does not provide quantitative specifics on the associated greenhouse gas emissions. For this reason, there is growing interest in moving away from using colors to categorize hydrogen in favor of using a carbon intensity figure, and the term "clean" is increasingly used to describe hydrogen with a low carbon intensity.

**Carbon intensity is the amount of lifecycle greenhouse gas emissions per unit of energy of fuel.**

Carbon intensity refers to the embodied emissions in a fuel source, and it is the metric used in clean fuels programs like California's Low Carbon Fuel Standard and Oregon's Clean Fuels Program. Oregon Department of Environmental Quality's administrative rules related to the Clean Fuels Program define carbon intensity as "the amount of lifecycle greenhouse gas emissions per unit of energy of fuel."[20] This lifecycle analysis includes emissions associated with the production and consumption of the fuel, including those related to processing, storage, transportation, and combustion, and is often referred to as "well to wheel."

The federal Infrastructure and Investment Jobs Act of 2021 directs US DOE to establish a GHG emissions standard for "clean" hydrogen that only includes emissions at the site of production as opposed to lifecycle emissions; the bill defines clean hydrogen to include hydrogen produced with a carbon intensity of no more than 2 kg $CO_2e$ per kg of hydrogen. The federal Inflation Reduction Act of 2022, however, includes a production tax credit for "qualified clean hydrogen," defined as a lifecycle GHG emissions rate of hydrogen production of no more than 4 kg of $CO_2$ per kg of hydrogen. In September 2022, US DOE released the Clean Hydrogen Production Standard (CHPS) Draft Guidance, which sets a "well-to-gate" boundary for the eligible carbon intensity of "qualified clean hydrogen," which is less inclusive of emissions than the well-to-wheels approach used by clean fuels programs.[7] A well-to-gate analysis includes emissions up to the point before a fuel is ultimately used whereas a well-to-wheel analysis includes the emissions associated with the end use of the fuel.

While ensuring that hydrogen's carbon intensity is quantified and communicated is not particularly controversial, a number of environmental advocates have expressed concern that assessing hydrogen *strictly* according to carbon intensity is not adequate and that a distinction should continue to be made between renewable and non-renewable hydrogen. The rationale for this is that even though hydrogen produced using a fossil fuel feedstock can have a low carbon intensity, this production would still support continued reliance on fossil fuels and slow down decarbonization efforts. Those in favor of only focusing on hydrogen's carbon intensity counter that the road to full decarbonization is expensive and hydrogen produced from fossil fuels with CCS is a critical intermediate step to building a hydrogen economy that will move closer toward zero emissions over time.

## SB 333 (2021) Definition of Renewable Hydrogen

Oregon does not currently have a definition for renewable hydrogen in its statutes or administrative rules, though SB 333 does provide a definition for the purposes of this study – "hydrogen gas derived from energy sources that do not emit greenhouse gases."

This definition raises some questions, the first being whether this means energy sources that intrinsically do not emit greenhouse gases, such as electricity generated from wind or solar power, or whether it might include energy sources that are associated with greenhouse gas emissions but where these emissions are captured and stored, as opposed to emitted to the atmosphere, as with fossil resources paired with CCS. A second question is whether this definition could include energy sources that emit GHGs when used to produce hydrogen but are considered carbon neutral by the state, such as biomass.

To answer these questions, ODOE considered the legislative intent of SB 333, how the state defines the difference between "renewable" and "clean" for the purposes of electricity, and definitions for "renewable" hydrogen used in other jurisdictions.

With regard to legislative intent, there were no specific discussions related to the definition of renewable hydrogen as the bill passed through the legislature. Some stakeholders who presented to legislative committees made suggestions of what type of feedstocks should be eligible to produce "renewable hydrogen," but the legislators did not comment on those. Because the study was to assess the relative benefits and challenges of *renewable* hydrogen, ODOE determined that a necessary part of the study is to suggest how best to define renewable hydrogen.

### *Defining "Renewable" and "Clean" for Electricity*

In 2007, Oregon passed legislation enacting a Renewable Portfolio Standard, or RPS, which requires electric utilities to meet an increasing portion of their in-state retail electricity sales with qualifying renewable energy. The bill stated three reasons for the RPS: to decrease Oregon's electric utilities' reliance on fossil fuels for electricity generation; to increase their use of renewable energy resources; and to promote research and development of *new* renewable energy sources in Oregon (emphasis added).[21]

Oregon's RPS statute does not define "renewable energy source" by attributes, but instead lists what specific types of renewable energy sources may be used to generate qualifying electricity for the RPS.

The eligible resources are:[22]

- Wind energy
- Solar PV
- Solar thermal
- Geothermal energy
- Some biomass sources
- Some biogas resources
- Some low-impact hydropower
- Some traditional hydropower

Given the RPS legislative intent of promoting new renewable resources, a second metric beyond resource type determines RPS eligibility – the age of the facility generating the electricity. With a few exceptions, only facilities that went into operation after January 1, 1995 are eligible for Oregon's RPS, which excludes much of the region's existing legacy hydropower. This has led to concerns that Oregon's government does not consider hydropower renewable, though that is not the case. Instead, the rationale was to ensure that *new* renewable projects were built. Also, existing RPS exemptions allow some generation from these legacy hydropower facilities (from efficiency upgrades) to qualify, and generation from post-1995 traditional hydropower facilities located outside of certain protected areas or certified as low impact can also qualify.

In 2021, Oregon enacted clean energy targets that require electric companies[ii] to reduce the GHG emissions associated with their retail electricity sales to 100 percent below a baseline by 2040. The act requires that these electric companies increasingly meet their retail load with "nonemitting electricity," which is defined as "electricity, including hydroelectricity, that is generated and may be stored in a manner that does not emit greenhouse gas into the atmosphere."[20] While the definition of nonemitting electricity makes no mention of "clean," the bill itself refers to the targets as "clean energy targets." And because this policy is concerned with reducing and then eliminating the GHG emissions associated with electricity consumed in Oregon as opposed to ensuring that new projects are built, hydropower is fully eligible.

This practice of pairing a "renewable" electricity standard with a "clean" one is happening in a number of states and these policies commonly allow for "clean" resources that may not be considered

[ii] Oregon statute defines electric companies to include investor-owned utilities and electricity service suppliers, but not consumer-owned utilities.

renewable for, say, an RPS, but that have zero GHG emissions, such as nuclear power or electricity generated from fossil fuels paired with CCS.[23] Hydrogen is increasingly being categorized in similar terms, where renewable hydrogen refers to hydrogen produced from renewable feedstocks and clean hydrogen refers to hydrogen with a carbon intensity below some threshold.

### *Existing Definitions for Renewable Hydrogen*

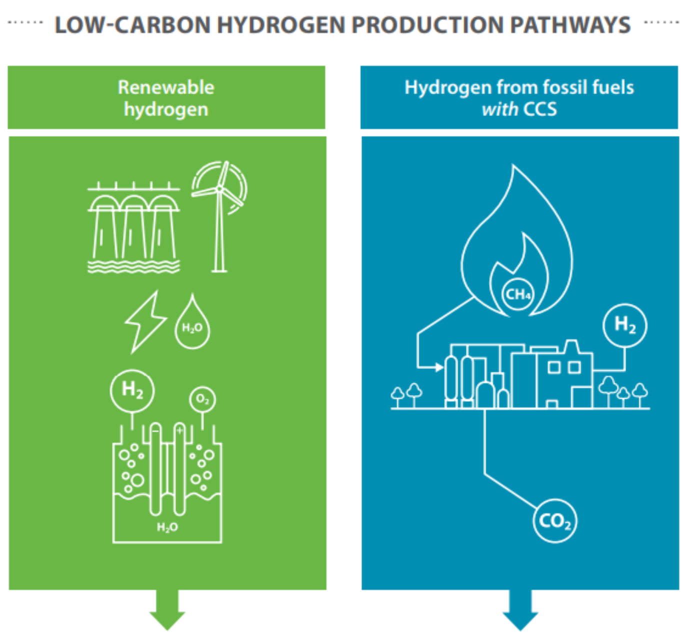
As discussed above, US DOE has not provided a definition for renewable hydrogen, and as states seek to add hydrogen to their clean energy strategies, they are developing their own.

Though Oregon does not have a statutory definition for renewable hydrogen, its RPS does allow for use of electricity generated from hydrogen for compliance if the hydrogen is produced from electricity generated by any of the eligible RPS sources except with a requirement that any hydropower used must also be certified as low impact.[iii] Additionally, the electricity used to produce the hydrogen must not also be used to comply with the RPS, i.e., there can be no double counting.[24] California's RPS treats hydrogen similarly.[25]

Washington's Clean Energy Transformation Act[26] defines renewable hydrogen as "hydrogen produced using renewable resources both as the source for the hydrogen and the source for the energy input into the production process."

Neither Canada's national hydrogen strategy[27] nor British Columbia's hydrogen strategy[28] explicitly define the term renewable hydrogen in words, though the British Columbia strategy includes a diagram labeled "renewable hydrogen" that shows hydrogen being produced electrolytically from renewable resources.

**Figure 3: Diagram Showing Definition of Renewable Hydrogen in British Columbia's Hydrogen Strategy[28]**




[iii] The Low Impact Hydropower Institute, or LIHI, certifies facilities that have avoided or reduced their environmental impacts according to the Institute's criteria. These criteria include fish passage and protection, water quality protection, watershed protection, and threatened and endangered species protection.

In the European Union, the EU Draft Green Hydrogen Rulebook describes renewable hydrogen as being "produced in an electrolyser [sic] that uses renewable electricity."[29]

### *ODOE's Interpretation of Renewable Hydrogen for this Study*

For the purposes of this study, ODOE interprets the definition of renewable hydrogen in SB 333 to include the following hydrogen production pathways:

1. **Electrolysis powered by renewable electricity, including legacy hydropower**
2. **Reformation of biogas**
3. **Gasification of biomass**
4. **Thermal conversion of biomass or biogas**

Even though this interpretation includes four main pathways, given that most of the renewable hydrogen development is currently focused on electrolysis, this report focuses almost exclusively on electrolysis.

# CHAPTER 3: STORAGE AND TRANSPORTATION OF HYDROGEN

As of 2019, 85 percent of the hydrogen produced is produced and consumed on-site, limiting the need for storage or transport outside of the general use needs of the facility.[30] The remaining 15 percent is produced, transported, and stored for other uses. This means that as hydrogen and renewable hydrogen are deployed for new end uses, the existing infrastructure would need to be expanded to support significant growth. The end use of the hydrogen plays a significant role in how the hydrogen is ultimately transported and stored.[31]

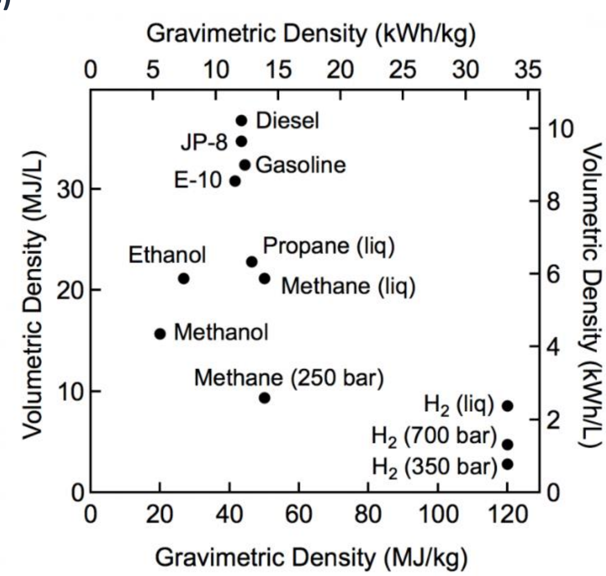
## Hydrogen Storage

Many of the properties of hydrogen require special materials and conversions to ensure safe handling. For example, hydrogen is a very light molecule and so the materials and construction of storage and transport mediums for hydrogen must be selected to mitigate leakage.[32] Hydrogen can also degrade certain materials and compromise their structural integrity, a process often referred to as hydrogen embrittlement. Varieties of carbon steel are often used for pipelines as they can be formed and welded, but they react badly when exposed to hydrogen gas, resulting in fatigue cracks.[33] The potential severity of hydrogen embrittlement depends not only on the materials used, but a number of operating conditions, including pressure and temperature.[34]

Hydrogen has a high gravimetric energy density – nearly three times the energy content of gasoline or diesel on a mass basis. However, the situation is reversed on a volume basis, where hydrogen has a much lower volumetric energy density than most fuels or energy carriers.[35] In practice, this means that if you had a weight limit of one kilogram, then hydrogen would be the most energy dense fuel to use. However, if you had a volume limit, then there are a number of fuels that would provide a higher energy density than hydrogen. Figure 4 shows that compressing hydrogen increases the volumetric density of hydrogen, as does liquefaction, but that this density is still much lower than other fuels at the same volume.

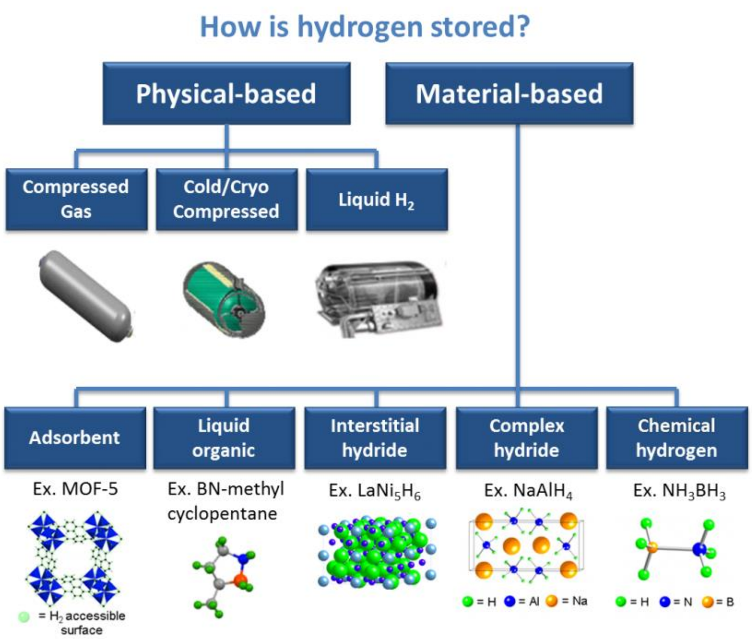
**Gravimetric energy density** is the available energy per unit of mass whereas **volumetric energy density** is the available energy per unit of volume.

**Figure 4: Comparison of Gravimetric Density and Volumetric Density of Fuels (Based on Lower Heating Values)[35]**



Because hydrogen has such a low volumetric energy density, it is generally compressed or liquified before storage. It can also be chemically altered into a different chemical substance, such as ammonia or methanol, or captured by an absorbent material. These forms of material-based transformations can be useful for the transport of the substance and can increase the potential for multiple end-uses.[19] For example, ammonia can be converted back into hydrogen or can act as a precursor for fertilizers and other industrial uses.

**Figure 5: Hydrogen Storage Methods[35]**




Storing hydrogen in large quantities requires considerations for available space, technologies required to compress the gas, suitable materials for containment, and the ability to meet necessary safety protocols. This includes selecting materials and parts that can maintain hydrogen at very high pressures while limiting leaks, which is extremely challenging due to hydrogen's extreme volatility.[31] Chemically transforming or absorbing the hydrogen will also have additional implications, including technology availability, round-trip energy losses, and safety and storage requirements for individual storage materials. All of these considerations have implications for costs, but it should be noted these costs are present whether the hydrogen is renewable or not. The various hydrogen storage methods are discussed in detail below.

### *Compressed Gas Storage*

Compressing hydrogen into a gas that is denser than at atmospheric pressure is the most well-established form of hydrogen storage. This form of storing hydrogen is most applicable to the final end-use of hydrogen for small-scale mobile and stationary applications, such as hydrogen provided by bulk gas distributors for medical, laboratory, and other uses. This is generally in the form of metal vessels that hold small amounts of hydrogen compared to the mass of the vessel and generally have pressures between 200-10,000 pounds-per-square-inch. They are categorized as Type I through IV, with Type I being the cheapest and smallest amount of storage, and subsequent vessel types being more costly but offering increasingly more gas storage capacity. Compressed hydrogen gas is readily available in Oregon through gas distribution companies, who generally manage the production, transport, and storage of the hydrogen.

Compressed gas is the most cost-effective storage option for small, on-site applications. It is particularly challenging when space for storage is limited, because of limitations in the amount of hydrogen gas this type of storage can hold. Type III and IV storage vessels can hold more hydrogen than Type I and II vessels, but are currently significantly more expensive largely due to these vessels being wrapped in carbon fiber that increases the strength of the vessel and therefore the amount of gas that can be stored.[31] Carbon fiber sells for about $15 per pound today, but researchers from Oak Ridge National Laboratory and their industry partners are working to reduce that to $5 per pound by making changes to the complex production process.[36] The US DOE estimates that as the costs for carbon fiber decrease, Type III and IV vessels could ultimately cost less than Type I cylinders.[37]

### *Liquid Hydrogen Storage*

Bulk hydrogen is generally liquified for storage because of the volume of space required to store the same amount of hydrogen in compressed gas vessels. Liquefying hydrogen, however, requires supercooling hydrogen to near-absolute zero, or -423 degrees Fahrenheit. As a result, liquefying hydrogen requires advanced liquefaction technologies, a significant amount of energy, and specialized storage vessels.

The storage tanks themselves can be the same Types I through IV as described above but would require significant insulation to maintain the cold temperature. Despite the insulation, some ambient heat will still penetrate the tank and cause the liquid to boil, and the resulting gas vapor must be released to avoid excessively high pressures.[37] This is referred to as "boil-off." The vented gas can be released into the atmosphere or captured and pressurized into compressed gas for other uses.

There are no liquid hydrogen production sites in Oregon, but there are several distribution companies that can supply liquid hydrogen.[38] Storing hydrogen in a liquid form is energy intensive and prone to produce loss through boil-off. Further, smaller storage vessels that have higher surface-to-volume ratios are more prone to this loss, which make subsequently smaller storage sites on long distribution chains more prone to product loss and therefore higher costs.[39] Currently, storing hydrogen in liquid form is limited to certain high-tech use cases, including as rocket fuel for space travel.[40]

**There are no liquid hydrogen production sites in Oregon, but there are several distribution companies that can supply liquid hydrogen.**

The costs to liquefy hydrogen are significantly higher than to produce compressed gas. Liquifying hydrogen is much more energy intensive, consuming the equivalent of more than 30 percent of the hydrogen's energy content.[39] For comparison, liquifying natural gas consumes 10 percent of the energy content. The costs are also higher to properly insulate the storage vessels and add venting features. There is an additional capital cost if the user wants to capture the vented gas and compress it for other uses. The inevitable loss of product in storage due to boil-off also contributes to higher overall costs than compressed gas storage, and the losses increase the longer the hydrogen is in storage.

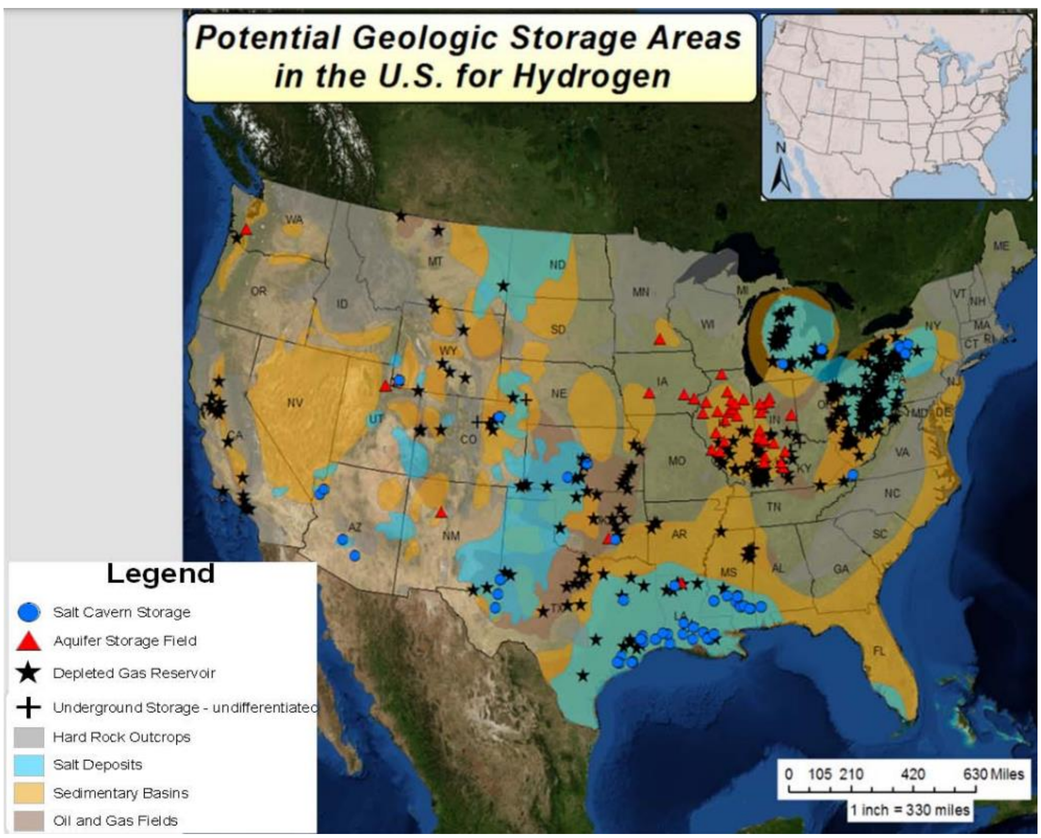
### *Geological Storage*

Geological storage of hydrogen is often the most cost-effective option for long-term, large-scale storage of hydrogen. Formations such as salt caverns, hard rock caverns, certain aquifer structures, depleted oil and natural gas fields, among others can be suitable to storing large quantities of gaseous hydrogen.[4] This would reduce the need for costly liquefaction of hydrogen for storage, has the benefit of providing economies of scale, and is an efficient method for storing and retrieving the hydrogen.

Hydrogen has been stored effectively in underground salt caverns since the 1970s. The Air Liquide Spindletop facility in Texas is able to hold up to 30 days of hydrogen output from a nearby natural gas steam reformation unit.[19] There are also plans to store clean hydrogen in a salt cavern in Delta, UT, to be dispatched up to months later to power combustion turbines for electricity. This facility has the potential to hold over 550,000 tons of hydrogen gas, enough to generate 150 GWh of clean energy.[41]

There are no salt caverns in Oregon for storage, and limited rock formations that might be amenable to excavation and storage.[42] One notable exception is the Mist natural gas field located in Columbia County.[43] This depleted natural gas field is currently used as a storage site for natural gas and may have the potential to store hydrogen.

**Figure 6: U.S. Geology with Potential as Underground Storage and Existing Natural Gas Geologic Storage Facilities[42]**



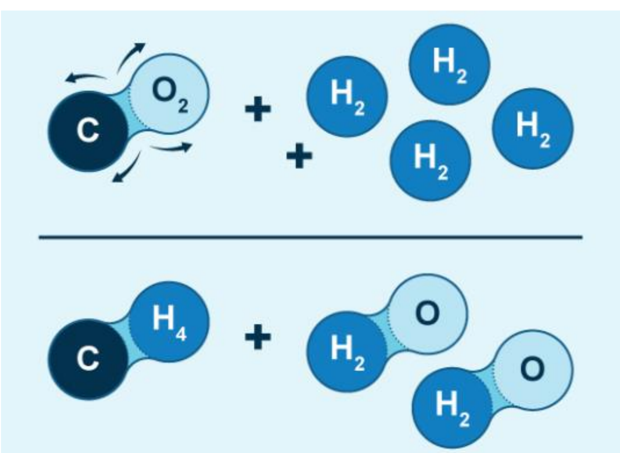
### ***Material-Based Storage***

Hydrogen can be converted into other chemicals that are easier to store and transport. The most commonly discussed carrier molecule is ammonia. This is a molecule made up of one nitrogen atom and three hydrogen atoms (hydrogen molecules contain only two hydrogen atoms) and is created by combining hydrogen and nitrogen under very high pressures, forcing them to react. Ammonia can be liquified at -27 degrees Fahrenheit and carries 1.7 times more hydrogen per cubic meter than liquid hydrogen alone.[44] Because ammonia is a common industrial chemical, particularly in the production of fertilizers, there is already a robust network of storage sites around the globe. In the U.S., ammonia is produced at 32 plants in 17 states, including in Oregon.[45] The Dyno Nobel ammonia production plant in St. Helens, OR produced 1,000,000 metric tons in 2021.[46] It requires 7-18 percent of the hydrogen's energy to convert it to ammonia, depending on the size and type of system used, and about the same amount to convert it back.[4] Ammonia is a toxic chemical, however, which requires safe handling. Accidental releases of ammonia require cleanup to reduce negative affects to the environment, and ammonia is capable of forming PM2.5, which is harmful particulate matter.

Other potential hydrogen carriers include toluene, dibenzyltoluene, methanol, and formic acid – these are referred to as liquid organic hydrogen carriers. All of these are carbon-based atoms and have the potential to contribute greenhouse gas emissions, which would offset any emissions benefits in creating clean hydrogen. These also are toxic chemicals that would require careful handling. These also require large amounts of energy to convert and reconvert the hydrogen. Organizations such as Sandia National Laboratory are actively studying, testing, and piloting new materials that can absorb and release hydrogen, including some solid materials.

Hydrogen can also be methanated, a process where carbon dioxide and hydrogen are combined to produce methane and water (see Figure 7). Methane (CH4) is essentially pure natural gas with no contaminants or other hydrocarbons, and it can serve as a drop-in fuel – a direct replacement – for natural gas in infrastructure, appliances, and pipelines. However, methane is a potent greenhouse gas and has the potential to leak from infrastructure in the same way that natural gas does.

**Figure 7: Methanation of Hydrogen Process[47]**



## Hydrogen Transport

Today, hydrogen is predominantly transported via trucks in gas or liquid form or through pipelines. Hydrogen can also be transported by rail or ships, though neither is currently happening in the U.S. The costs of transporting hydrogen depend on the volume of hydrogen, the distance its being transported, and whether it is compressed, liquefied, or transformed into an energy carrier, like ammonia, or a liquid organic hydrogen carrier (LOHC), like methanol. Every time that hydrogen is converted – either via pressure or temperature or chemistry – energy losses occur and costs go up, especially if the hydrogen must undergo a re-conversion at the end of its transport journey.

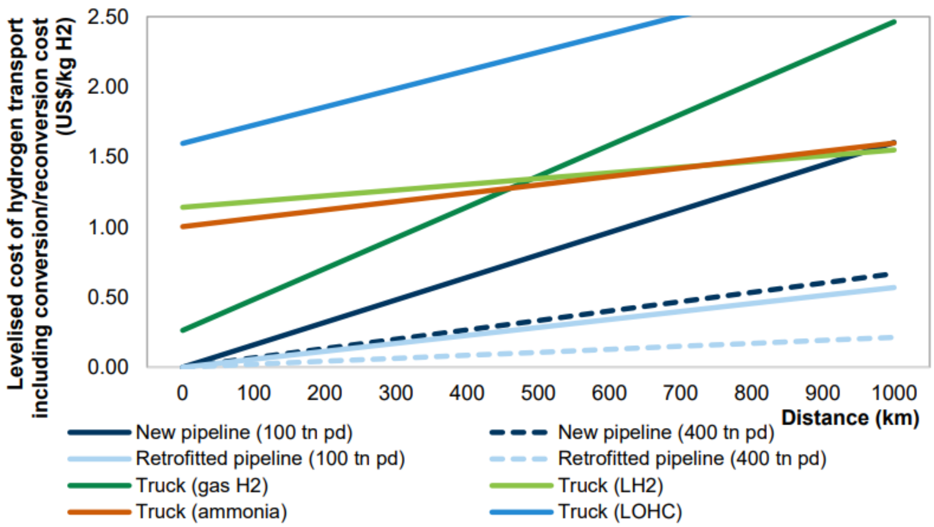
### *Transport Via Pipeline*

Hydrogen can either be blended into a natural gas pipeline network or it can be transported via dedicated hydrogen pipelines. There are about three million miles of natural gas pipelines in the U.S.; in Oregon, there are about 16,000 miles of distribution main lines and about 730 miles of high-pressure transmission pipeline.[48] There are also about 1,600 miles of dedicated hydrogen pipelines in the U.S., namely in Texas; in Oregon, there are none.

For blending, the percent of hydrogen by volume that can be blended into a natural gas pipeline depends on the design and condition of the pipeline, pipeline equipment, and the ability of end use appliances to safely use the mix. Blending pilot projects in Europe have led to an acceptance of about 20 percent hydrogen by volume as the safe limit of blending without modifying infrastructure. The California Public Utilities Commission (CPUC) is investigating the operational and safety concerns with injecting hydrogen into the existing natural gas pipeline system and has found that large-scale demonstration projects would be necessary to evaluate the effects of hydrogen gas on the many different metal alloys and polymeric materials used throughout the state's gas system, as well as varying operating conditions. A study commissioned by CPUC found that gas blends of hydrogen and methane would leak at higher rates compared to pure methane. Additionally, hydrogen's lower energy content as compared to methane requires greater operating pressure in a pipeline compared to pure methane, which would result in increased leak flow rates. The study recommended that it would be necessary to conduct case-by-case studies for different gas networks to determine the appropriate blend percentage that would mitigate risks.[34]

Pipelines are likely to be the most cost-effective medium for transporting hydrogen distances up to about 2,000 miles or so. As the distance increases, the cost of transporting pure hydrogen through a pipeline increases at a faster pace than for other transport methods because of the greater number of compressor stations required along the pipeline.[49] For pure hydrogen pipelines, new pipelines can be built or existing natural gas infrastructure can be retrofitted to handle 100 percent hydrogen. Goldman Sachs finds that retrofitted pipelines are likely to be more economical than new pipelines, but it depends on capacity (see Figure 8). At longer distances, the solid blue line for the new, lower-capacity pipeline (100 tons per day) becomes more expensive than truck transport of hydrogen gas or ammonia at distances of about 620 miles (1,000 km) and beyond. While the new pipeline with the higher capacity (400 tons per day), shown by the dotted dark blue line, is just slightly more expensive than the retrofitted higher-capacity pipeline (the solid light blue line) at distances under 620 miles, the retrofitted higher-capacity pipeline is clearly the least-cost delivery method for short-distance transportation of hydrogen.

**Figure 8: Levelized Cost of Hydrogen Transport Including Conversion/Reconversion Costs**[50]




In Europe, a recent study by Siemens estimated the costs for retrofitting existing natural gas pipelines in Germany to be about 10-15 percent of the cost of a newly constructed pipeline; Germany approved guidelines for the conversion of gas transmission lines in 2020.[51] In England, a consortium of companies operating the Get H2 Nucleus model project are investigating conversion of a portion of natural gas pipeline to pure hydrogen, including initial tests for suitability.[52]

### *Transport Via Truck*

For shorter distances, up to about 600 or so miles, trucks are an economical option for transporting hydrogen. Hydrogen is predominantly delivered over the road in gaseous tube trailers or in cryogenic liquid tankers. For tube trailers, U.S. Department of Transportation regulations limit the allowable pressurization of the tubes to 250 bar (a metric unit of pressure), though they have granted some exemptions for transport at higher pressures.[53] To transport greater volumes of hydrogen than tube trailers, hydrogen can be moved as a liquid. Liquefaction consumes more than 30 percent of the energy content of the hydrogen being liquefied and is expensive, but it can be a more cost-effective choice over longer distances due to the greater mass of hydrogen delivered.[39]

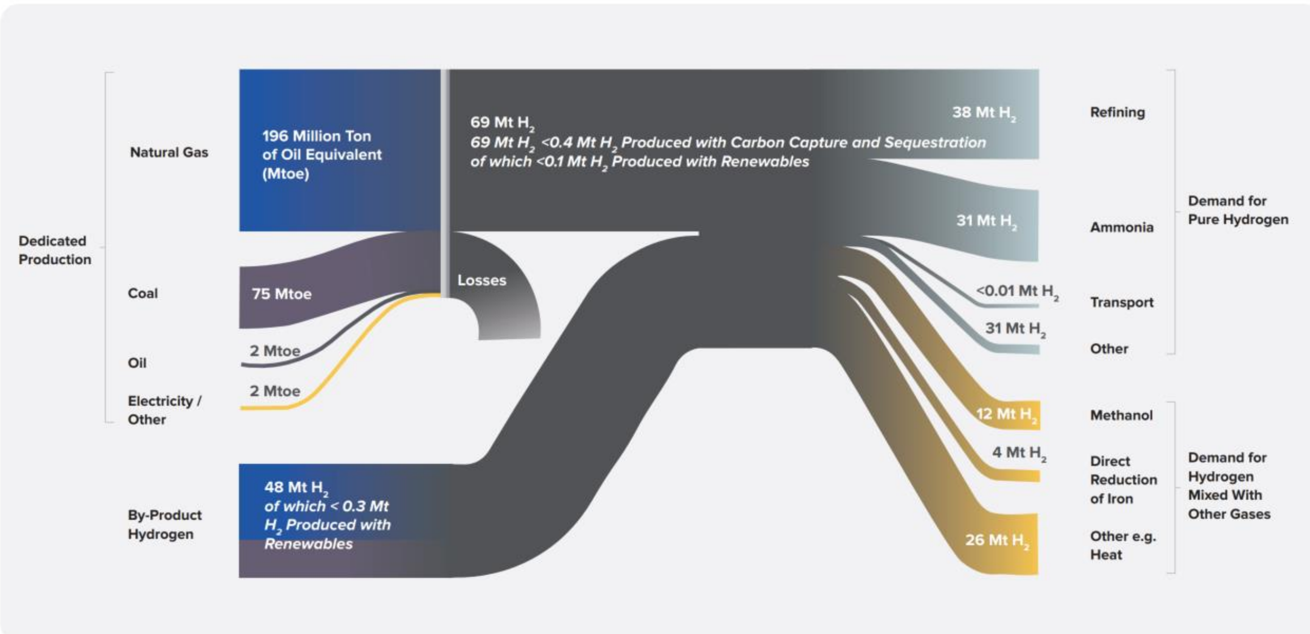
### *Transport Via Ship*

Hydrogen can be delivered via ship, either as a liquid or converted into a carrier like ammonia, methanol, or LOHCs. Today, shipping liquid hydrogen is in the pilot stage, with the first proof-of-concept shipment in January 2022, from Australia to Japan.[54] The main challenge is keeping the hydrogen chilled enough to stay in its liquid form while avoiding any cracking of the containment materials.[55] According to the International Renewable Energy Agency, Agora Energiewende (a German think tank), and Wood Mackenzie, shipping hydrogen as ammonia makes more sense economically than shipping pure hydrogen. Ammonia is already transported via ship commercially and in a liquid form at low pressure, ammonia has three times the energy density of compressed hydrogen and 1.5 times that of liquefied hydrogen.[56]

# CHAPTER 4: INVENTORY OF CURRENT HYDROGEN USE IN OREGON

Globally, hydrogen is predominantly used in industrial applications, such as petroleum refining, production of steel and other metals, food processing, and chemical production.[4] It is the primary feedstock for the production of ammonia, about 80 percent of which is used to manufacture fertilizers.

**Figure 9: Global Hydrogen Production Sources and End Users**[19]




Beyond refining, chemicals, and steel industries, hydrogen is used in the following sectors:[57]

- Aerospace
- Analytical labs
- Beverages
- Biotechnology
- Cement and lime
- Electronics
- Food processing
- Glass
- Medical
- Pharmaceuticals
- Pulp and paper
- Rubber and plastics
- Semiconductors
- Waste and wastewater
- Welding and cutting

There is no existing data on specific U.S. hydrogen consumers, nationally or at the state level. To determine the annual consumption of hydrogen in Oregon, ODOE conducted research to identify companies operating in the state in the sectors that use hydrogen. ODOE then contacted these companies via email and telephone to determine whether they used hydrogen in their business processes located in Oregon and, if so, to request data on their hydrogen consumption. ODOE contacted each company a minimum of three times.

The responses ODOE received from its outreach fell into the following categories:

- No response.
- Do not use any hydrogen in Oregon.
- Did use hydrogen for a product in the past but no longer use it.
- Do use hydrogen but at de minimis levels (no more than 50 kg per year).
- Do use hydrogen but have concerns about sharing data.

Few of the companies responded to ODOE's outreach and of those that did, even fewer were willing to share details about their hydrogen consumption. These companies cited confidentiality concerns as they considered this data to be competitive intelligence. In its outreach, ODOE informed companies that it would not report their data in such a way that identification of any firm's individual consumption could be determined, and the level at which ODOE reported data would depend on the responses received. If the Department received enough data from companies in a single sector, for example, ODOE might have been able to report hydrogen consumption data for that sector. If there were not enough data responses to report by sector, the Department informed companies that they would report the data publicly as a state total. ODOE informed companies who raised concerns related to confidentiality and competitive advantage that they could request in writing that the Department Director make a determination that their data is proprietary (based on answers to a number of questions) and to exempt this data or redact it in the event of any related public disclosure requests. However, while an Oregon state agency Director may determine that data provided to them are proprietary and confidential, an appeal to this determination could be made with the state's Attorney General.

Given the low response rate to ODOE's requests for data, the Department was not able to fulfill the legislative requirement to produce a hydrogen inventory. Without specific data to produce an inventory of hydrogen consumption in Oregon, ODOE estimates that the largest consumers of hydrogen in the state include semiconductor manufacturers, food processors, research and analytical labs, glass manufacturers, and distribution center operators using hydrogen fuel cell forklifts. Understanding the current breadth of uses of hydrogen in Oregon will require support and input from industrial users to complete an in-depth assessment. ODOE discussed with the study's Technical Advisory Committee the possibility of estimating hydrogen consumption by some companies in the state based on publicly available information, but this would require further study to determine whether enough information was available publicly to develop a methodology.

# CHAPTER 5: POTENTIAL APPLICATIONS OF RENEWABLE HYDROGEN IN OREGON BY 2030

Determining where renewable hydrogen might be deployed in Oregon in the near term first requires a look at where hydrogen might fit as an end use and then second, whether renewable hydrogen is likely to be used instead of fossil-based hydrogen, especially low-carbon hydrogen from fossil sources paired with CCS.

Broadly speaking, there are differing opinions about what roles low-carbon and renewable hydrogen should play in a decarbonization strategy. The main points of difference are how big a role they might play and what niches they might best fill. As a decarbonization option, both low-carbon hydrogen and renewable hydrogen are in competition with other clean technology alternatives and adoption for specific use cases will depend on the properties of hydrogen, supportive policies, costs, geopolitics, and other factors.[58]

As to where renewable hydrogen should be used first or at all, a merit order of renewable hydrogen deployment can be developed based on considerations such as availability of substitutes, GHG emissions reductions potential, costs, and performance. The first half of this chapter discusses the different criteria that can be used to determine the most valuable end uses for renewable hydrogen and the second half discusses specific sectors where renewable hydrogen will likely be deployed between now and 2030.

## Determining the Highest-Value Applications for Renewable Hydrogen

There is no single "best" path for Oregon to meet its climate and energy goals – each potential strategy results in trade-offs related to cost, speed of GHG emissions reductions, land use, jobs, benefits accrued to frontline communities, etc. Oregon does not currently have a statewide energy strategy to guide decisions around what trade-offs are preferrable, so it is difficult to determine what end uses policymakers and stakeholders in the state may choose to focus on for renewable hydrogen.

**There is no single "best" path for Oregon to meet its climate and energy goals – each potential strategy results in trade-offs.**

Clean energy expert Michael Liebreich has suggested a merit order for uses of clean hydrogen – a clean hydrogen ladder – where the top rungs represent where it would be unavoidable for economy-wide decarbonization down to where it would be uncompetitive with other decarbonization technologies.[58] Liebreich developed the clean hydrogen ladder as a response to some hydrogen advocates who suggest that clean hydrogen could and might be deployed like a Swiss Army knife – able to address nearly any decarbonization need.

**Figure 10: Clean Hydrogen as a Swiss Army Knife – Expectation that Clean Hydrogen Can Meet Any Necessary End Uses for Decarbonization[58]**

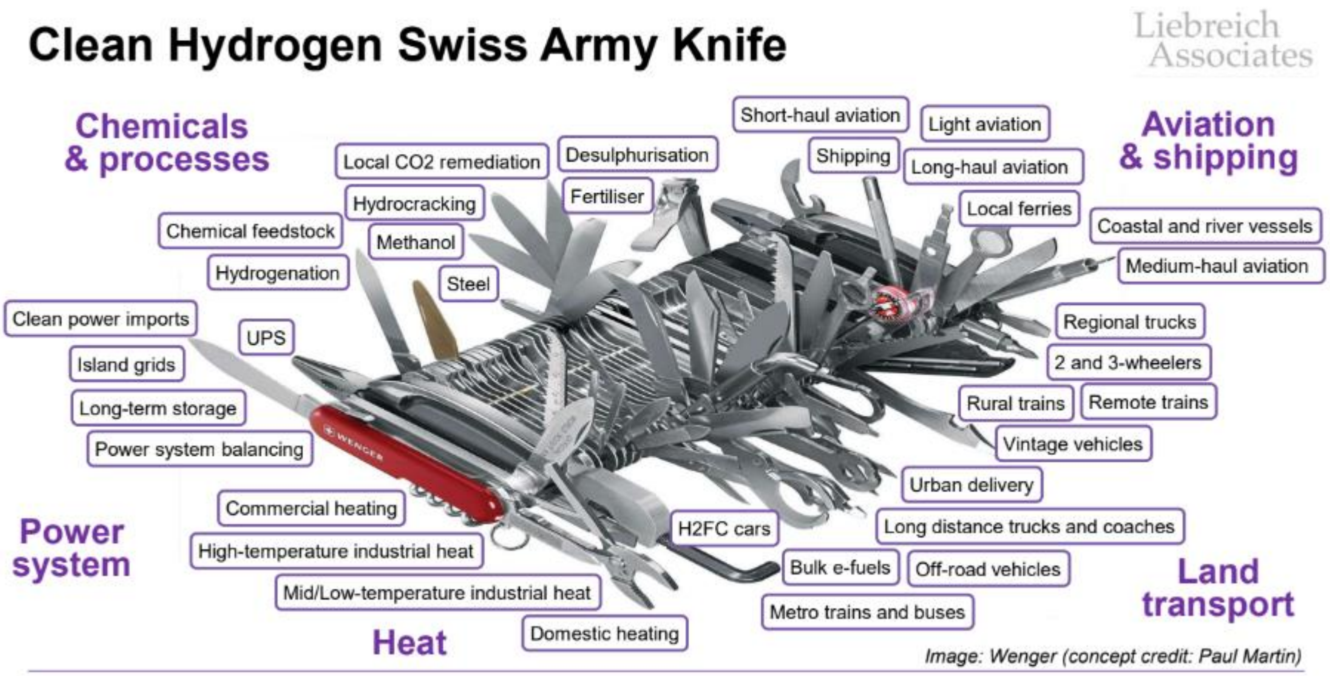
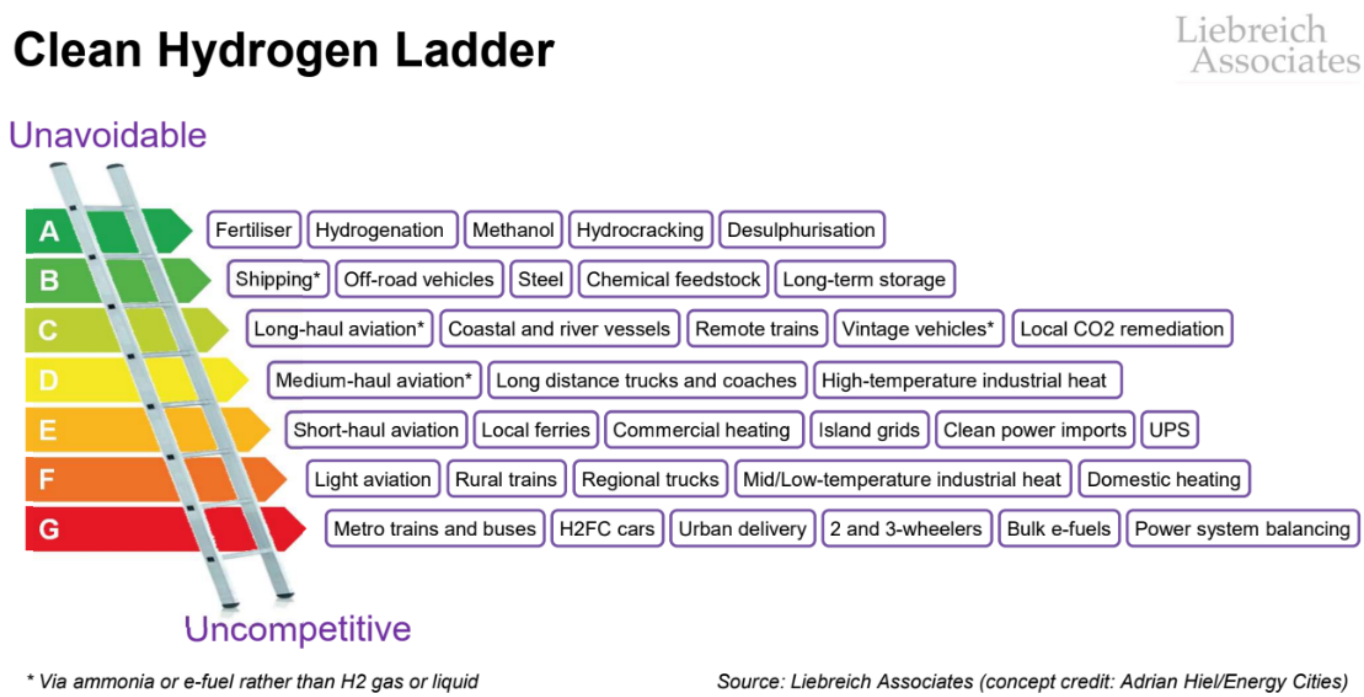



**Figure 11: Clean Hydrogen Ladder – A Merit Order Deployment[58]**




The Swiss Army knife and Hydrogen Ladder can also be applied to renewable hydrogen instead of clean hydrogen. Renewable hydrogen *could* be used throughout the transportation, power, heating, and industrial sectors (the Swiss Army knife), but the Hydrogen Ladder tries to ground this in reality with an order based on where renewable hydrogen could not only beat the incumbent fossil technology, but also beat every other zero-carbon option for that use case.[59] However, it is important to remember that renewable hydrogen may be deployed for uses where it is not necessarily the best option but where market actors still wish to use it as a solution. The following are some of the factors that may help determine where renewable hydrogen might be best deployed in Oregon.

## Factors That Affect the Deployment of Hydrogen for Specific End Uses

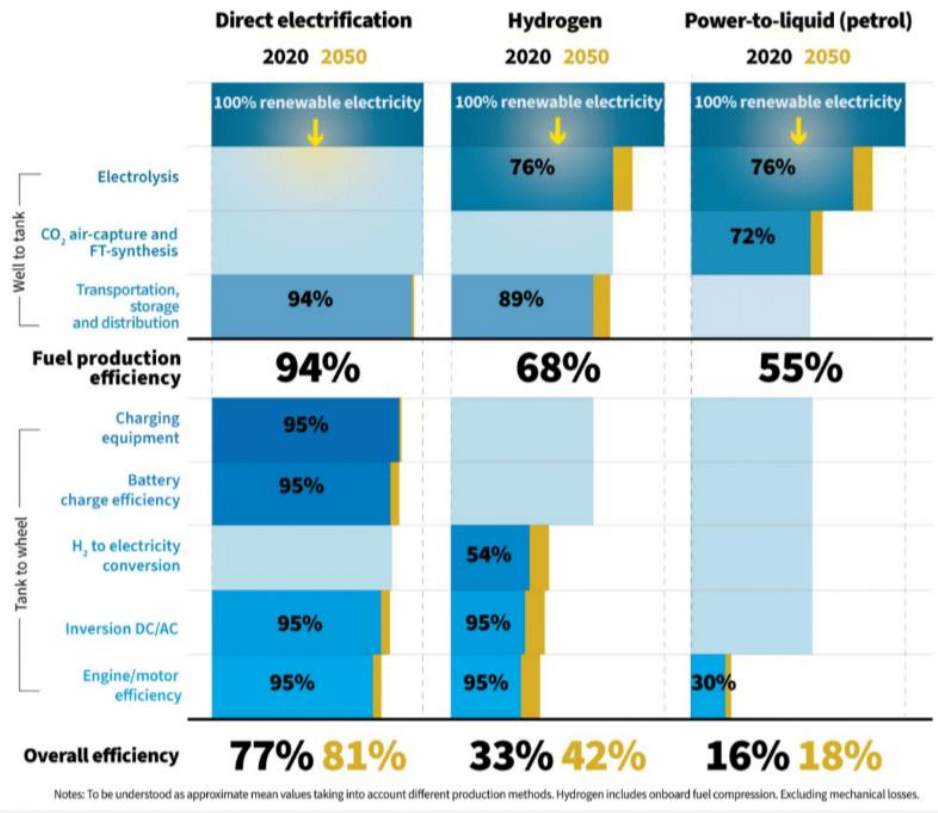
### *The Properties of Hydrogen*

As discussed in Chapter 3, hydrogen has a low volumetric energy density. One implication of this low density is that for transportation uses, a higher volume of fuel must be carried on board to go the same distance as other fuels. And the high-pressure tanks needed for compressed or liquified hydrogen by far outweigh the hydrogen they carry. This is not necessarily a concern for terrestrial or marine vehicles, but it currently limits the use of hydrogen for medium- and long-haul aviation. Airbus estimates that it would take 3,000 liters of unpressurized hydrogen gas at ambient temperature to release the same amount of energy as a liter of conventional jet fuel; even liquefying the hydrogen and storing it at cryogenic temperatures would require four liters of hydrogen to provide the same amount of energy as a liter of jet fuel.[60] There is research and development happening today to develop new storage tanks made of lighter materials that would allow for planes to carry a larger supply of hydrogen and thus travel farther than is possible today.

### *Efficiencies of Hydrogen Production and Use*

All energy carriers suffer from efficiency losses each time they are produced, converted, or used. For hydrogen, there are also losses associated with the energy needed to store and transport it at pressure or at cryogenic temperatures. The efficiency of using electricity to produce hydrogen via electrolysis is between about 50 and 80 percent, depending on the type and size of the electrolyzer.[50] When adding in the energy to store it, transport it, and then convert it back into electricity in a fuel cell electric vehicle (FCEV), the roundtrip efficiency can fall as low as 30 percent.[4] Figure 12 shows the overall efficiency of fueling vehicles with electricity as compared to hydrogen or other electrolytic fuels (power-to-liquids on the figure). The most efficient end uses of renewable hydrogen will be those that require the fewest conversions and reconversions.

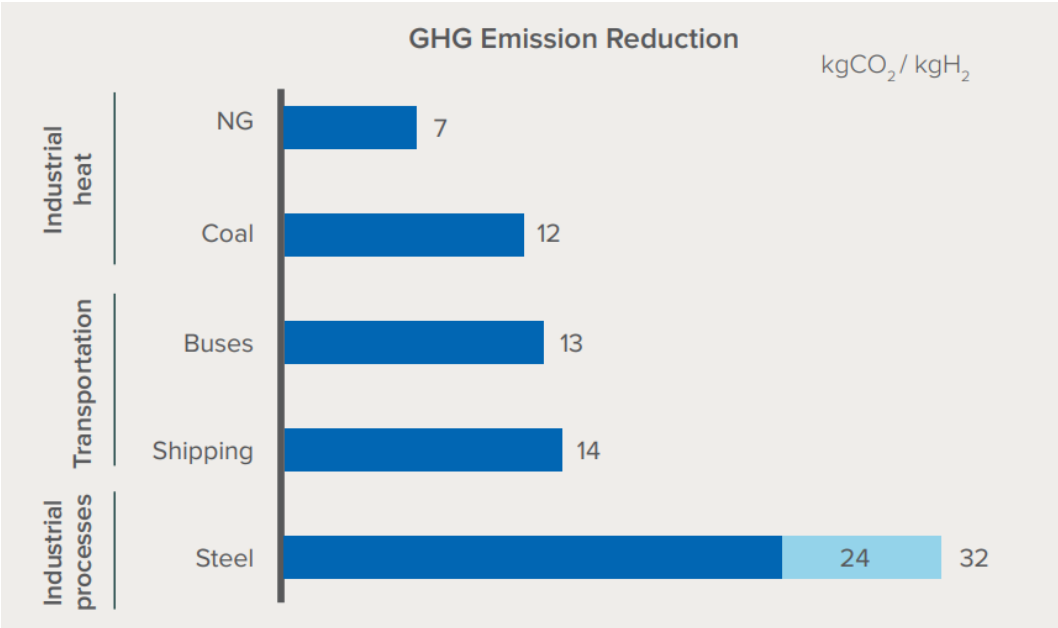
**Figure 12: Electricity-to-Wheels Efficiency of Various Zero-Carbon Vehicle Pathways[61]**




### *GHG Emissions Reduction Potential*

The GHG emissions reduction potential of hydrogen is based on the carbon intensity of producing the hydrogen and the GHG emissions being reduced by substituting that hydrogen for an end use where a fossil fuel would otherwise be used. For renewable hydrogen, the carbon intensity will likely include emissions related to transporting it, and possibly also for compressing or liquifying it. In the near term, where it is expected that supply of renewable hydrogen will be tight and the cost may be higher than that of suitable substitutes, end uses for renewable hydrogen can be assessed based on their "bang for buck" when it comes to GHG emissions reductions. RMI analyzed five use cases for hydrogen and found that the CO2 reduction effectiveness for using a kilogram of hydrogen varies widely, as shown in Figure 13 (where NG refers to natural gas).[62] The analysis only takes into account the avoided emissions for using hydrogen instead of fossil fuels and not any emissions associated with the hydrogen itself.

**Figure 13: Comparison of Achieved CO2 Emissions Reductions for Each Consumed Kilogram of Hydrogen in Five Use Cases**[62]




The two different bar colors shown in Figure 13 for steel represent the emissions reduction effectiveness of the hydrogen used (32 kgCO2 per kgH2) versus a normalized effectiveness (24 kgCO2 per kgH2) when considering electricity used in the final stage of the decarbonized version of steelmaking that could have been used to produce hydrogen. For buses, RMI based its analysis on studies from Europe assessing the performance of FCEV buses displacing diesel bus and used European Union grid carbon intensities. For shipping, the assumption is that the hydrogen is used to produce ammonia, which is then combusted in place of bunker fuel. For industrial heat, this is a direct comparison of the thermal content of each fuel contrasted with the displaced fuel's CO2 emissions.

Another end use suggested for renewable hydrogen is blending into natural gas pipelines. From a GHG emissions reduction standpoint, this end use fares worse than many others. This is because adding 20 percent renewable hydrogen by volume (the assumed maximum safe limit for blending) only results in a six percent reduction of GHG emissions due to hydrogen's lack of density and the need for increased pressure to move it through the pipeline.

### *Costs of Renewable Hydrogen and Availability of Substitutes*

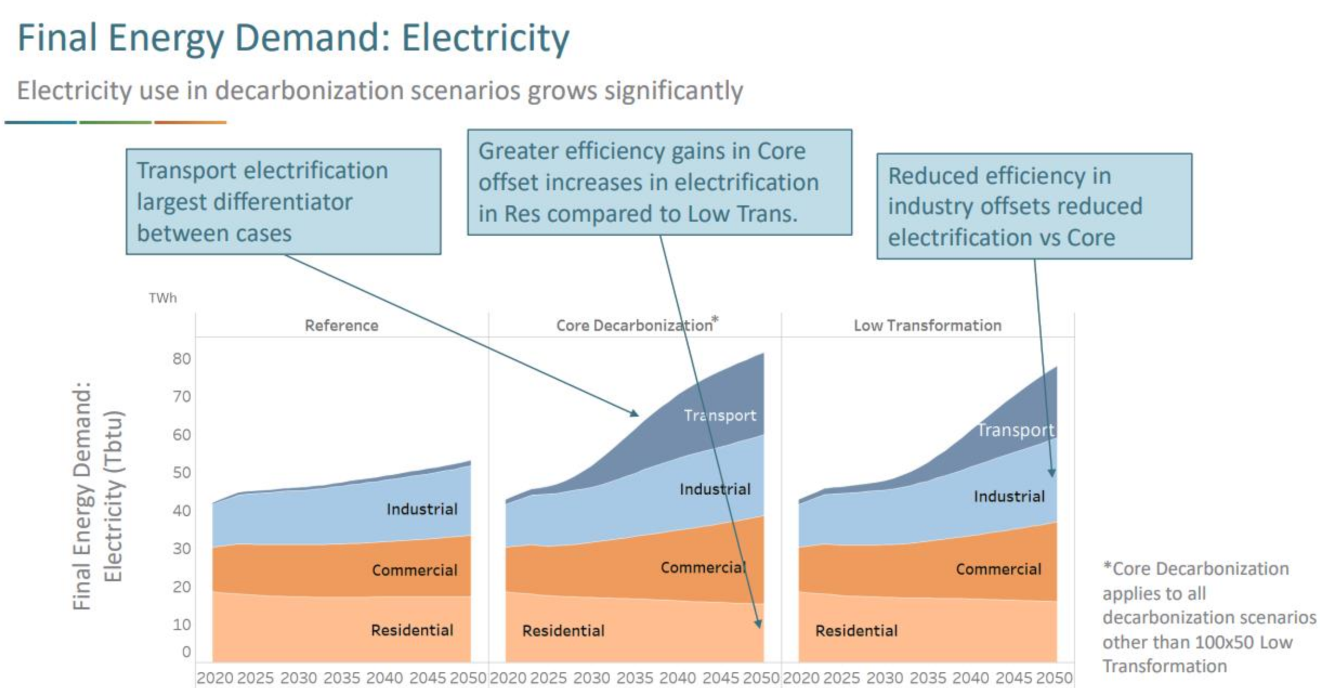
Supportive policies can help renewable hydrogen become more competitive compared to suitable substitutes. For example, renewable hydrogen could replace natural gas in a number of industrial end uses, but renewable hydrogen is currently a more expensive fuel than natural gas, even before considering any necessary infrastructure changes. Low-carbon hydrogen produced from fossil fuels paired with CCS can also be considered a substitute for renewable hydrogen. The projected costs of renewable hydrogen and the potential effect on adoption are discussed in more detail in Chapter 7.

### *Potential Supply of Renewable Hydrogen*

Supportive policies can address some of the barriers to development of renewable hydrogen projects in Oregon and the Northwest, but there are still constraints related to how much renewable electricity might be available to power those projects.

The Northwest Power and Conservation Council's (NWPCC) 2021 Northwest Power Plan[63] forecasts that the regional demand for electricity will grow from just under 21,000 aMW[iv] in 2018 to about 29,000 aMW by 2050, with large increases in demand coming from transportation electrification and data centers. The 2021 Power Plan does not include potential future electricity demand for electrolysis. Evolved Energy Research's Oregon Clean Energy Pathways Study[64] uses six decarbonization scenarios and a Reference scenario to forecast electricity demand out to 2050 (see Figure 14) for eleven Western states, including Oregon. The Core Decarbonization graph in the middle shows the results of all six of the decarbonization scenarios except for the Low Transformation scenario, which is shown in the third graph. The Low Transformation scenario assumes slower electrification and efficiency gains as compared to the other scenarios while the Reference scenario, on the left, models the assumption that there are no new GHG emissions targets in the West. For this study, the models selected hydrogen in the later years for transportation decarbonization. Once the models selected hydrogen, the electrolyzers then were assumed to provide grid balancing services as well, but again, not until later years.

**Figure 141: Forecasted Electricity Demand by Sector for Western States 2020-2050[64]**




Given the clean energy and GHG emissions reduction goals in the West and the Northwest, much of the generating resources built to meet future demand will be renewable. Figure 15 shows the pace of development of renewable resources in Oregon from 2000-2019 while Figure 16 shows the NWPCC's

[iv] aMW denotes average megawatts. One megawatt is 1 million watts and one average megawatt is one million watts delivered continuously 24 hours a day for a 365-day year. A MW is a measure of capacity whereas aMW is a measure of energy.

forecast for renewable generation additions across Western states to meet clean energy targets. Figure 15 shows that the highest annual amount of new installed capacity in Oregon was about 900 MW in 2012. While Figure 16 is showing a cumulative forecast for Western states (all states west of the Rockies, including California), the minimum total amount of new renewables needed by 2040 is about 350,000 MW. That represents a *very* aggressive build out of new renewable generation resources – ten times the entire Northwest hydropower system in terms of installed capacity.

**Figure 15: Annual Additions of Renewable Electricity Resources in Oregon Since 2000[65]**

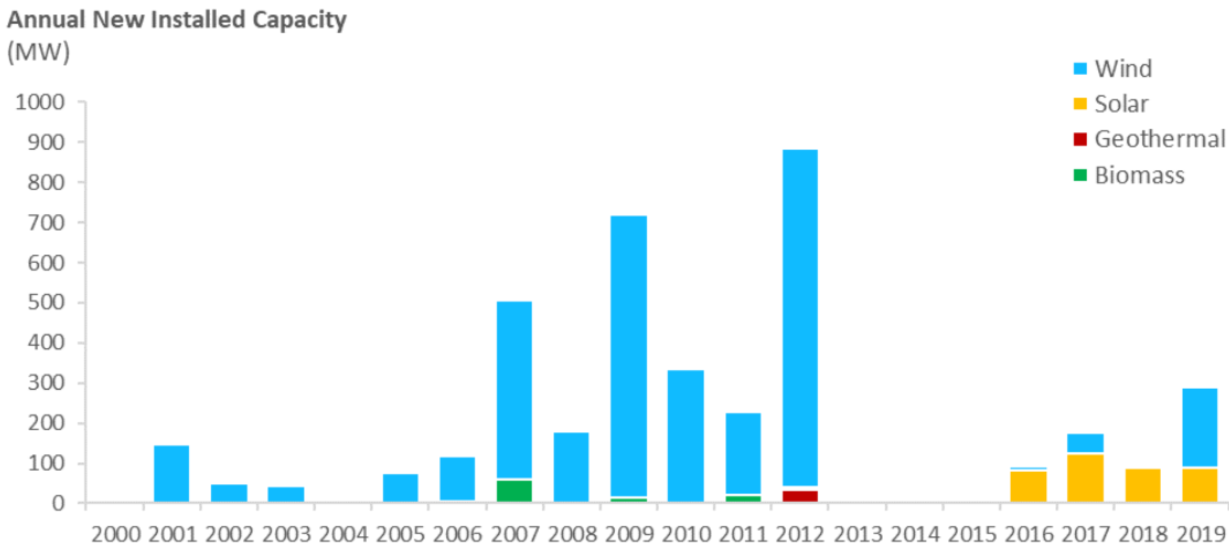
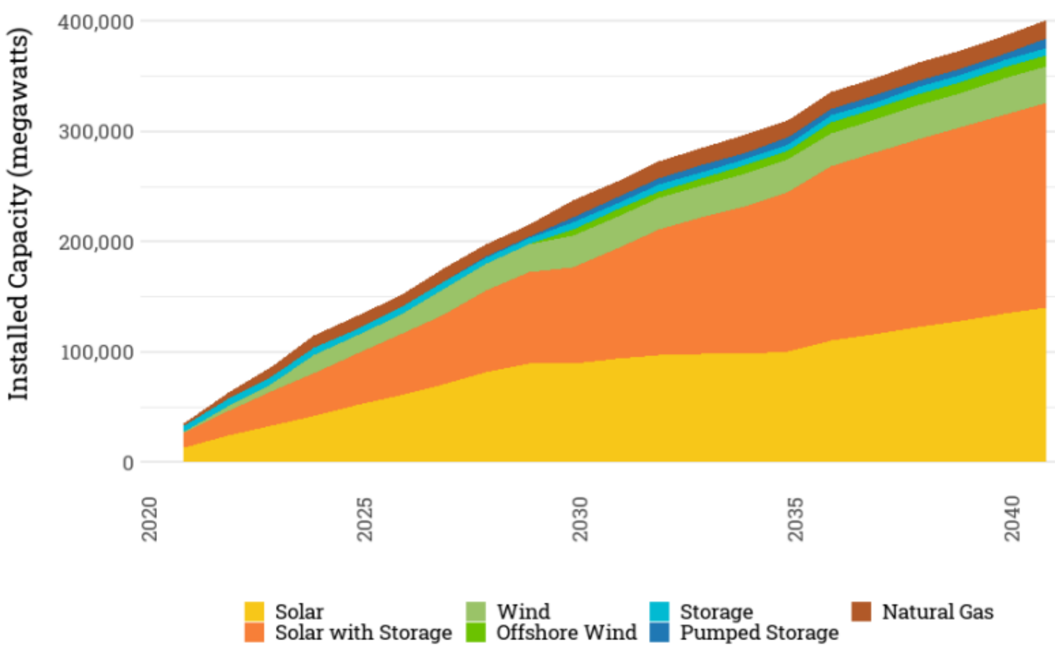
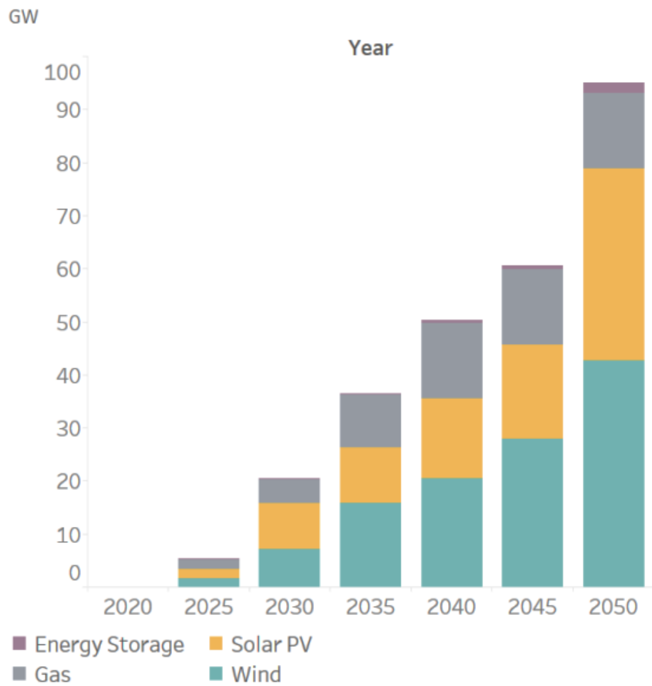



**Figure 16: Projected Renewable Electricity Generation Additions Across Western States to Meet Clean Energy Targets[63]**



Zooming back into the Northwest, the 2019 Northwest Deep Decarbonization Pathways Study forecasts a need for almost 80,000 MW of new wind and solar by 2050 to meet decarbonization goals (Figure 17).

**Figure 17: Forecasted Cumulative New Resource Build in the Northwest**[66]




These forecasts demonstrate the expectation for electricity demand to grow in the coming years, due in no small part to the push to electrify transportation, buildings, and industrial processes. It is also expected that much of the new generating resources will be renewable given states' goals related to clean energy and GHG emissions reductions. However, there are significant challenges in deploying that much renewable electricity generation. The [2022 Oregon Renewable Energy Siting Assessment](#) (ORESA)[67] found "…that there is enough renewable energy potential in the state to meet Oregon's energy and climate goals, while acknowledging that there are… notable challenges to renewable energy resource development associated with transmission infrastructure and with siting and permitting criteria that weigh policy and legal priorities." The ORESA report finds that unless there is development of additional transmission infrastructure in Oregon, the state will face challenges in "accessing its renewable energy potential."

The challenges involved in developing the scale of renewables necessary to meet Oregon's goals may impact the availability of sufficient renewable electricity to power electrolyzers to produce renewable hydrogen at scale in Oregon, at least in the near term. And if the supply of renewable hydrogen is constrained, then it may be worthwhile to consider which end uses provide the best decarbonization benefits.

### *Policies That Support Hydrogen and Renewable Hydrogen Production and Consumption*

Adopting hydrogen beyond the sectors where it is already in use represents costs associated with upgrading or replacing infrastructure, changing business processes, and possibly paying more for hydrogen than the fuel it is replacing. To support development of a broader hydrogen and renewable hydrogen economy, policies are necessary to help address costs and other challenges. Policies and regulations that directly support hydrogen include low carbon fuel standards, carbon pricing, zero-emission vehicle adoption goals and requirements, tax incentives, electrolytic tariffs, research and development investments, and safety regulations.[27] [68] Some of these policies, like a low carbon fuel standard, could provide benefits for using low-carbon hydrogen of any kind, while others can be and often are crafted to favor renewable hydrogen over non-renewable hydrogen, including low-carbon hydrogen, or to apply solely to renewable hydrogen. The recently passed federal Inflation Reduction Action includes a production tax credit for hydrogen and ties the amount of the benefit to the produced hydrogen's lifecycle GHG emissions, providing the most support for hydrogen with the lowest carbon intensity, regardless of the feedstock.[69]

## Potential Applications for Renewable Hydrogen in Oregon by 2030

There are a number of ways that renewable hydrogen could be used in Oregon, though, as discussed above, some will have a higher value depending on whether one is measuring the speed and amount of GHG emission reductions, costs, operational efficiencies, the availability of other low-carbon options, or the potential near-term available supply. To some extent, the market will determine where and how renewable hydrogen is used in Oregon, but existing and future policies can also shape the emerging market. For example, blending renewable hydrogen into natural gas pipelines is not the most effective end use from a GHG emissions reduction standpoint, but natural gas utilities in Oregon may find it to be of strategic importance in meeting their compliance requirements under the Climate Protection Program.

Determining *when* renewable hydrogen might be deployed at scale for some end uses (i.e., before 2030) is also an estimate based on the same factors as *where* it might be deployed. Recent federal grants and tax credits for renewable and low-carbon hydrogen may speed up the adoption of it for some end uses while pilot projects may help determine where renewable hydrogen may or may not be appropriate. For example, there was much fanfare in the press earlier this year when the German state of Lower Saxony rolled out five passenger trains powered by hydrogen, along with future plans to replace all diesel-powered trains in that region with hydrogen trains.[70] However, in October of this year, another state in Germany – Baden-Württemberg – announced that it would no longer consider hydrogen-powered trains as a potential replacement for diesel trains after a study it commissioned found them to be up to 80 percent more expensive than electric options.[71] The timing of when renewable hydrogen might be adopted in some sectors will depend on the interplay between how recent federal grants and tax credits affect the price of renewable hydrogen, the speed of technical advances and efficiency gains, learnings from research and development and pilot projects, and international hydrogen market development.

Considering various metrics for determining the highest-value end uses for renewable hydrogen (as just discussed), current market activity, state goals and policies, federal funding, and projected costs, the likeliest deployment of renewable hydrogen in Oregon by 2030 are discussed below, in an estimated order of value.

### *Substitution of Existing Hydrogen Use in Oregon with Renewable Hydrogen*

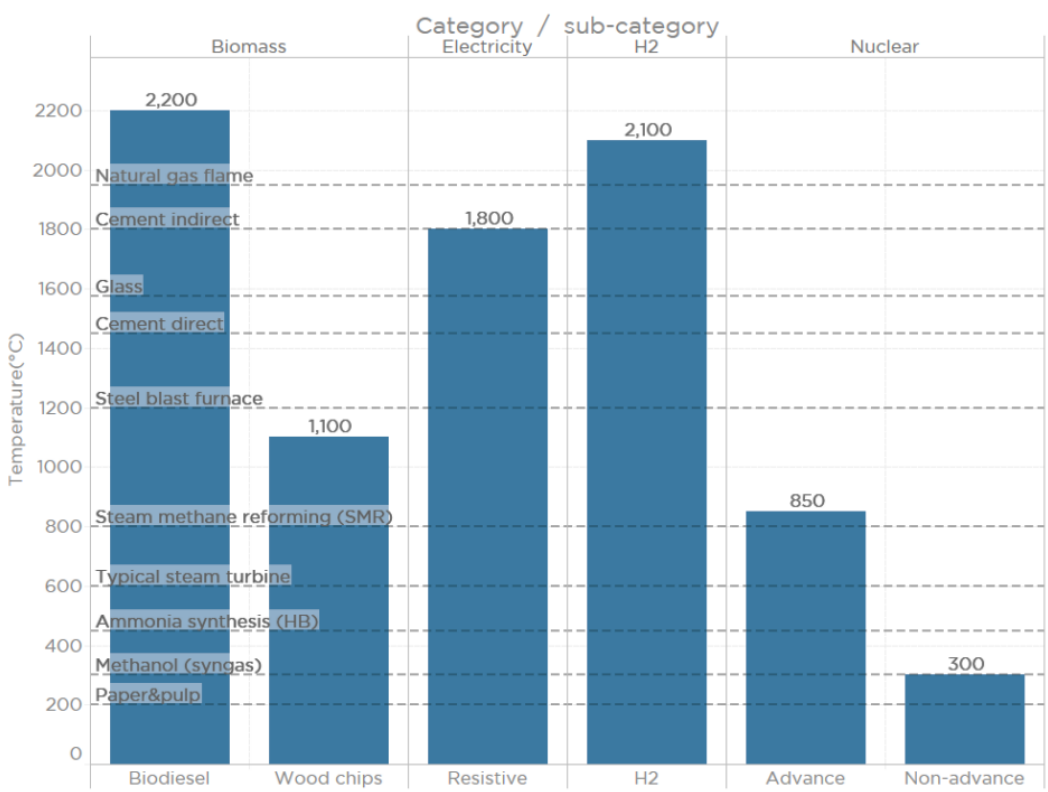
The most straightforward end use for renewable hydrogen in Oregon is substituting it into any process where fossil hydrogen is currently used. This is a no-regrets strategy that will yield immediate GHG emissions reductions without requiring any changes to infrastructure. The only costs to this change will be the difference in price between fossil hydrogen and renewable hydrogen. According to Goldman Sachs, "the clean hydrogen revolution begins with the de-carbonization of existing hydrogen markets."[50] Wood Mackenzie expects that about 80 percent of low-carbon hydrogen deployed globally this decade will be used to replace existing uses of hydrogen produced from fossil fuels.[72]

### *High-Temperature Heat for Industry*

A number of industries require process heat for everything from melting, gasifying, or drying materials to catalyzing chemical reactions. This heat can be applied directly or indirectly, and there are three main temperature ranges for industrial heat: low temperature (<100°C), medium temperature (100-400°C), and high temperature (>400°C). Most high-temperature heat is provided by the combustion of fossil fuels (though electricity can be used where certain conditions are met), whereas medium-temperature heat usually comes from steam created using fossil fuels. Low-temperature heat is usually waste heat from boilers or from other higher-temperature processes.[30]

There are several decarbonization options for industrial heat needs, but as the temperature requirement rises, the options thin out. Figure 18 shows that for six low-carbon feedstocks for industrial heat, only hydrogen and biomass can provide high enough heat to replace processes that use natural gas flame.

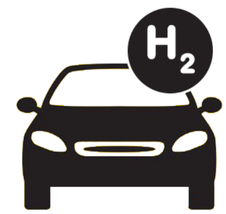
**Figure 18: Temperature Requirements for Selected Industries and Temperature Available for Low-Carbon Heat Source Options[73]**



For low- and medium-temperature processes where there are numerous options for decarbonization, the most effective one will be determined by how well the process and infrastructure are suited to the use of a substitute and its cost. A 2019 study found that substituting hydrogen produced from natural gas paired with CCS would add 10-50 percent to wholesale production costs, and at present prices, renewable hydrogen would add even more costs.[73] NW Natural has said in conversation with ODOE staff that they are considering producing hydrogen from natural gas paired with CCS to provide to industries like pulp and paper mills with a goal of transitioning to providing them with renewable hydrogen in the future.

### *Transportation*

#### Light-Duty Vehicles




Presently, electricity is far more commercialized as a fuel for light-duty vehicles than hydrogen, with more vehicle models available, a growing fueling infrastructure, and lower upfront and maintenance costs as compared to hydrogen FCEVs. For these reasons, many analysts consider electrification, not hydrogen, to be the key decarbonization technology for light-duty vehicles.[74] [75] For example, at the start of 2021, there were about 25,000 hydrogen light-duty FCEVs in operation globally. By October 2021, 11,674 of those were in operation in the United States.[76] This is in contrast to the more than 16 million light-duty plug-in hybrid electric and fully electric vehicles in use around the world in 2021.[77] Electric vehicle charging is increasingly available at public stations, workplaces, and residences and as of 2021, there were over 600 electric vehicle charging stations in Oregon, with over 1,500 charging ports.[78] To date, there are no hydrogen fueling stations in operation in Oregon.

FCEVs could play a role in future light-duty transportation for applications where fast refueling times, less performance sensitivity to cold temperatures, and greater range are important. FCEVs also may be a solution for Oregonians who cannot charge electric vehicles at home, such as those who do not have driveways or who live in multi-unit dwellings. Also, if the price of hydrogen falls under $3.00/kg, light-duty FCEVs could be cost competitive with battery electric vehicles, even factoring in higher purchase prices and maintenance costs for FCEVs.[79] In Oregon, FCEVs are recognized in state goals related to zero-emission vehicle adoption and eligible for clean vehicle rebates. This, coupled with recent announcements from BMW and Toyota[80] that they'll offer new FCEV models as early as 2025, means that it is possible that Oregon could see light-duty FCEVs in the state before 2030.

Adoption of FCEVs in neighboring states could also lead to greater adoption in Oregon. In California, there are 60 open retail hydrogen fueling stations for light duty vehicles (and another 35 that are in the permitting or construction phase) to service the 10,127 light-duty FCEVs in the state as of December 2021.[81] [82] At least 33 percent of the hydrogen dispensed at state-funded fueling stations must be renewable, and at least 40 percent of the hydrogen must be renewable to be eligible for the state's Low Carbon Fuel Standard.[83] [84] California's Air Resources Board estimates the state's total on-road FCEV population will grow to 30,800 by 2024 and 61,000 by 2027.[85] The catalyst for this hydrogen transportation economy in California was the California Energy Commission's sizable funding of retail hydrogen fueling stations ($20 million per year to fund up to 100 stations) and the magnitude of legislative, regulatory, incentive, procedural, and structural efforts to support the hydrogen economy in the state. In Washington state, the legislature approved $2.55 million for the development of the state's first hydrogen fueling facility, to be built in Chehalis along I-5,[86] and created an eight-year FCEV pilot program that applies a 50 percent sales and use tax exemption for new or leased FCEV light-duty passenger cars and trucks and medium-duty passenger vehicles.[87] The development of the Chehalis fueling site could generate more interest in Oregon hydrogen fueling stations that could link Washington and California and create a "Hydrogen Highway," similar to the West Coast Electric Highway that was foundational to EV adoption along the West Coast in the 2010s.

The Oregon Department of Transportation completed a Hydrogen Pathway Study in April 2022, looking at potential hydrogen fueling needs and investments if hydrogen fuel cell vehicles represent a portion of zero-emission vehicles in the light-, medium- and heavy-duty sectors in Oregon by 2035.[76] The study estimates that if just five percent of Oregon's light-duty zero-emission vehicle goals are met with FCEVs rather than battery electric vehicles, there would be about 100,000 light-duty FCEVs in the state by 2035, necessitating approximately 47 public hydrogen fueling stations to serve these vehicles.

#### Medium-Duty and Heavy-Duty Vehicles

FCEVs could play a role in medium-duty transportation, but hydrogen is considered most attractive for heavy-duty vehicles where a continuous operation cycle requires longer range and faster fueling and/or where the lighter weight of hydrogen versus batteries affects operation and payload capacity. This includes long-haul trucking and transit buses. There are about 6,000 hydrogen fuel cell buses in operation globally; California has 61 in operation[88] and plans to deploy more than one hundred more.[81] In Oregon, TriMet completed a feasibility study on hydrogen fuel cell buses and Lane Transit District has indicated interest in hydrogen fuel cell buses because of their extended range as compared to battery electric buses.[76]

Though there has been a recent increase in the FCEV medium- and heavy-duty models available commercially, there are no hydrogen fueling stations in Oregon, including those that could accommodate larger vehicles. The ODOT Hydrogen Pathway Study assumes that widespread adoption of these vehicles in Oregon, beyond early adopters and pilot and demonstration projects, is not likely until after 2030 without specific policy support. One vehicle type that may see higher adoption before 2030 is hydrogen fuel cell forklifts. These are already in use at Amazon locations in Oregon and across the Pacific Northwest, with credits being generated for hydrogen fuel cell forklift use in the Clean Fuels Program for the first time in 2021.[89] In August 2022, Amazon announced that it had over 15,000 fuel cell forklifts in operation across 70 fulfillment centers and plans to grow that number to 20,000 across 100 locations by 2025.[90]

### *Chemicals and Other Energy Carriers*

In addition to serving as a fuel itself, hydrogen can be used as a feedstock to produce other fuels, including ammonia, methanol, and renewable diesel. Today, about 38 percent of global hydrogen demand is for ammonia production and another 15 percent for methanol production.[50] Ammonia is predominantly used for the production of fertilizers, but also for other industrial applications, such as synthetic fibers. Methanol is used for the manufacture of several solvents that can in turn be used to produce plastic. Ammonia and methanol are increasingly being considered as aviation and marine fuels. Renewable diesel uses hydrogen for a "hydrotreating process" where biomass is reacted with hydrogen under elevated temperatures and pressure. Based on its research, ODOE expects ammonia and renewable diesel production as likely end uses for renewable hydrogen in Oregon by 2030.

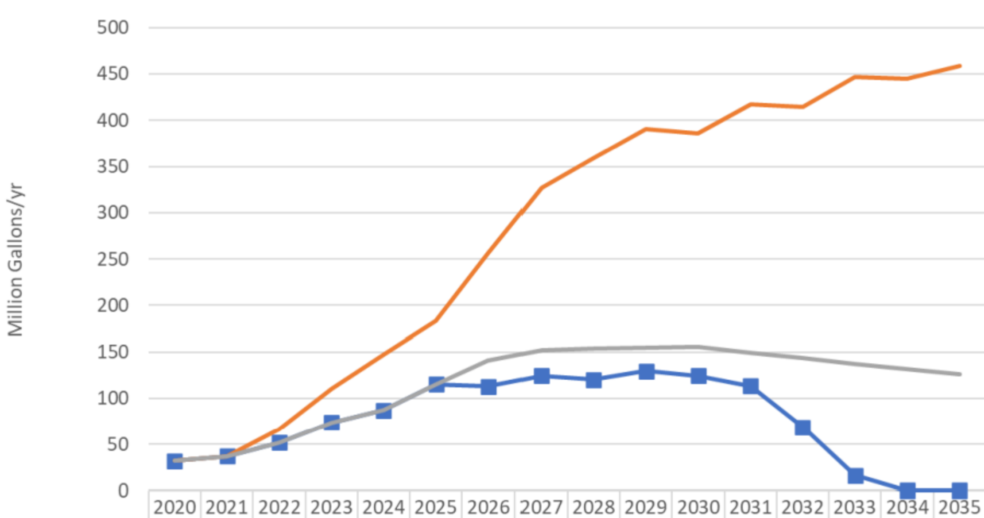
## Ammonia

Industrial ammonia is produced using the Haber-Bosch process, which involves using steam to strip hydrogen from natural gas and then combine it with nitrogen from the air at high temperature and pressure.[91] This energy-intensive process is responsible for about 1.3 percent of annual global GHG emissions from the energy sector.[92] Ammonia is considered "green" when renewable electricity is used to produce the hydrogen and to power the ammonia production. As discussed in Chapter 2, green ammonia can be used as a carrier to store and transport renewable hydrogen. It can also be used in a fuel cell to produce electricity, or as a marine fuel. Though there is currently only one fertilizer production facility in Oregon, Obsidian Renewables has suggested a hydrogen hub concept where renewable hydrogen would be used to produce green ammonia for eventual production of lower-carbon fertilizer.[93] For the marine sector, it is likely that green ammonia from renewable hydrogen won't play much of a role until after 2030, which is when ammonia-fueled vessels are expected to be commercially available.[50]

## Renewable Diesel

Renewable diesel can be used as a substitute for fossil diesel as a transportation fuel and is eligible for credits under Oregon's Clean Fuels Program. With a lower carbon intensity than traditional diesel, renewable diesel use is considered an intermediate decarbonization strategy as the transportation industry transitions to zero-emissions vehicles. For example, as TriMet shifts to replacing diesel buses with zero-emissions buses, the agency has also shifted to using only renewable diesel for the remaining diesel buses in its fleet.[94] Based on analysis done for Oregon Department of Environmental Quality on future Clean Fuels Program compliance scenarios, it seems likely that renewable diesel demand in Oregon will rise over the next few years, eventually plateauing in about 2026-2027. This is shown in Figure 19, where Scenarios A and C are the most likely according to study author ICF. Scenario B, which shows a marked increase in renewable diesel demand, does not factor in recent policy changes in Oregon, including adoption of the Advanced Clean Trucks rules.

**Figure 19: Renewable Diesel Volumes in the Oregon Clean Fuels Plan by Modeling Scenario[95]**




| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scenario A | 32 | 37 | 52 | 74 | 87 | 115 | 113 | 124 | 121 | 130 | 125 | 114 | 69 | 16 | 0 | 0 |
| Scenario B | 32 | 37 | 66 | 111 | 147 | 183 | 256 | 327 | 359 | 391 | 386 | 418 | 415 | 447 | 445 | 459 |
| Scenario C | 32 | 37 | 52 | 74 | 87 | 115 | 141 | 152 | 154 | 155 | 155 | 149 | 143 | 137 | 132 | 126 |

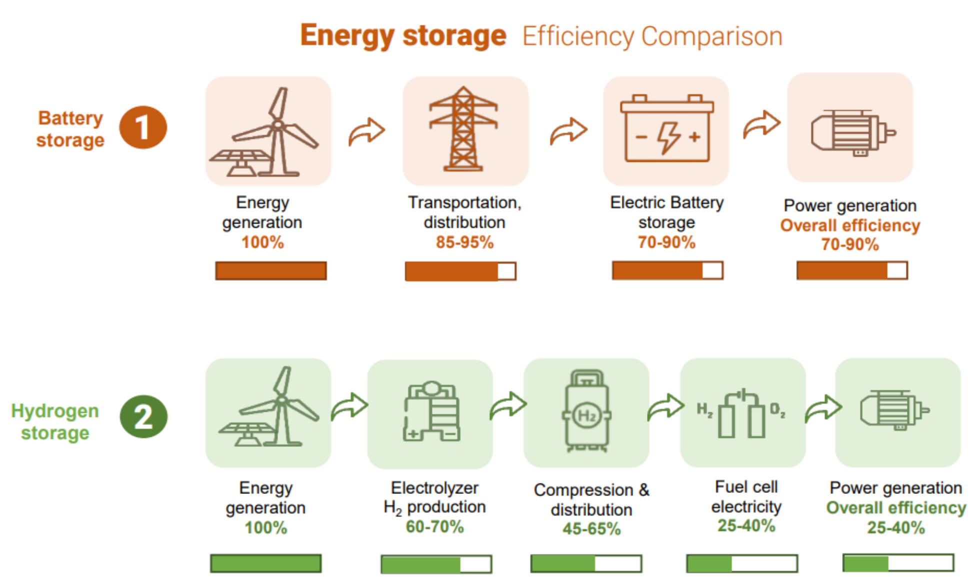
Even as Oregon likely transitions away from renewable diesel consumption in the 2030s, there may be a market for exporting the fuel to other states not as far along in their decarbonization journey. There is no current production of renewable diesel in Oregon, but that may change by 2025, when the NEXT Renewable Fuels Port Westward renewable diesel facility is hoping to begin commercial operation, depending on siting certification. However, NEXT plans to use fossil feedstocks to produce hydrogen and not renewable hydrogen. There are no other publicly announced renewable diesel manufacturing facilities in Oregon, but this sector could be an end use for renewable hydrogen before 2030 if NEXT chooses to use renewable hydrogen in its process or another facility is proposed.

### *Energy Storage in the Electric Sector*

Energy storage technologies in the electric sector can shift when energy is available for consumption across short, long, and seasonal timescales. As more variable renewable resources are added to the grid and more firm fossil fuel resources are retired, energy storage becomes increasingly critical to maintaining grid reliability. There are not widely accepted, uniform definitions for short-duration versus long-duration energy storage. In a recent literature review, the National Renewable Energy Laboratory (NREL) found that long-duration energy storage can refer to anywhere from four hours to multiple days, with 10-plus hours being used most frequently to differentiate long-duration storage from short.[96] The boundary between long-duration and seasonal energy storage is equally murky, though NREL has suggested that long-duration energy storage could be considered anything between 10-100 hours and seasonal storage would be for any duration over 100 hours.[97]

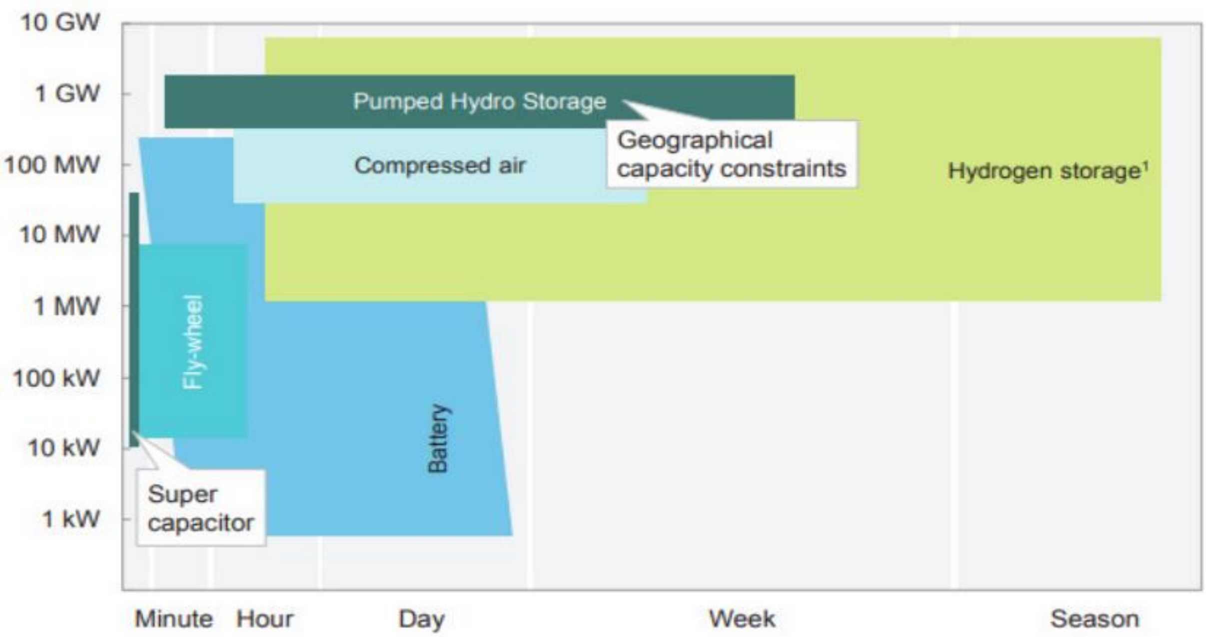
Lithium-ion batteries are the technology to beat for short-duration storage of a few seconds to a few hours but become less economical when sized to discharge for longer durations due to high cost per unit capacity. Hydrogen can be used for energy storage of any duration, but the lower round-trip efficiency (especially compared to batteries) and frequent discharges required for shorter-term storage make it more economical for longer-duration storage needs, especially seasonal storage. Figure 20 shows that battery storage can be up to 90 percent efficient whereas hydrogen storage tops out at about 40 percent efficient.

**Figure 20: Efficiency Comparison of Energy Storage Using Batteries Versus Hydrogen[50]**



NREL considers hydrogen to be one of the four most promising technologies for seasonal storage[97] and Goldman Sachs considers hydrogen to be the "optimal" solution for seasonal storage.[50] Figure 21 shows that batteries, super-capacitors, and compressed air lack either the power capacity or the storage timespan needed to address seasonal energy imbalances.

**Figure 21: Capacity Versus Discharge for Energy Storage Technologies[50]**




There are no available estimates for how much seasonal storage Oregon or the Pacific Northwest region might need, and this is partly due to the expectation that these resources will become necessary closer to the final 10 percent or so of the clean energy transition.[98] While hydrogen is considered to be one of the most cost-effective options for seasonal energy storage, there is a lot of variability in that cost driven by local storage opportunities.

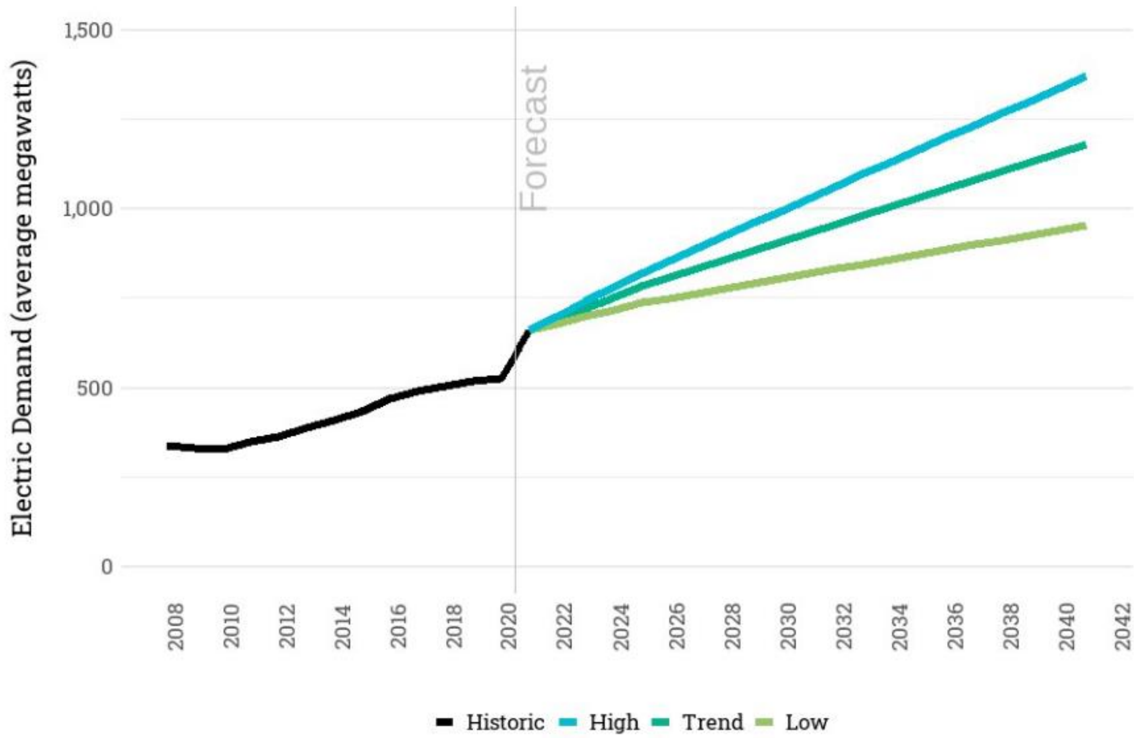
### *Back-Up Power*

Many businesses use back-up, or standby, power generators to keep their operations running in case of power disruptions. Part of inventorying a city or county's potential resilience includes identifying whether critical public service providers – hospitals, fire and police departments, wastewater treatment plants, etc. – have on-site back-up generation capabilities. Data centers, which use large amounts of electricity and rely on a dependable supply, have also invested in back-up power.

While there has been increasing interest in and deployment of renewable microgrids in Oregon, most back-up power is still provided by diesel generators, which produce GHG emissions. Many companies who are looking for zero-carbon options for back-up power are considering hydrogen fuel cells. For example, Microsoft has pledged to eliminate diesel fuel use as part of its 2030 carbon negative goal. Microsoft began investigating hydrogen fuel cells as a replacement for diesel back-up generation in 2014 and has run a number of successful test projects since then, culminating in testing this year of a 3 MW hydrogen fuel cell array to prove it could function in real-world conditions.[99]

As of April 2021, ODOE estimated that there were at least 18 back-up generators in Oregon with a capacity of 25 MW or larger.[100] Looking at data centers only, the NW Power and Conservation Council estimated that the total electricity demand for data centers in the Northwest was over 529 aMW, a figure they expect to grow annually by between 1.9 and 3.7 percent (see Figure 22).[101] For Oregon-specific demand, the Council estimates that the average connected load for large data centers in 2021 was about 370 MW.[102]

**Figure 22: Data Center Demand for Electricity in the Northwest (average megawatts)[101]**




Projects using hydrogen fuel cells for back-up power in the Northwest are either in the conceptual or pilot phase. In addition to Microsoft's test projects, Klickitat Valley Health in Washington received funding from the state to purchase a 100 kW hydrogen fuel cell for use as a back-up generator and for a microgrid pilot project.[103] It is possible that hydrogen may be adopted for back-up power generation by 2030, but it is unclear to what degree and whether the hydrogen used would be renewable hydrogen.

### *Electricity Generation and Grid Balancing*

As discussed in Chapter 5, electrolyzers can provide valuable grid services by nature of their flexibility in ramping up and down at a moment's notice. In this sense, their load shedding capabilities can serve as a substitute for short-duration battery energy storage in some cases. This sort of flexibility is similar to that of other large, controllable loads, like the aluminum smelters that once operated in the Pacific Northwest. Hydrogen fuel cells can also be used as short-duration grid energy storage, though with the lower round-trip efficiency as compared to batteries, this is not likely to be a common end use. However, hydrogen fuel cell installations sited as back-up power for facilities like data centers or hospitals could be used to send extra power to the grid in times of high demand if the incentives are worthwhile to the operator.

Analysts expect that as the market for hydrogen and renewable hydrogen grows, hydrogen could be combusted for electricity generation. However, projections differ at this point on whether these facilities will be needed to run constantly or only as peaker plants that would be called upon at times of high demand. Modeling of the electricity sector in the Pacific Northwest has shown that traditional renewable resources like wind and solar coupled with energy storage can achieve about 90 percent decarbonization as long as the remaining 10 percent can be met with firm dispatchable generation (one example is hydropower) or long-duration storage.[79] In its 2020 analysis of the long-term market potential for hydrogen in the West, Energy and Environmental Economics (E3) found that as more inexpensive renewables are added to the grid, many gas plants will face lower utilization rates and thus be good candidates for repowering with turbines that can run on a mix of natural gas and hydrogen. In a 2019 study of resource adequacy in the Pacific Northwest, E3 found that trying to reach 100 percent grid decarbonization only using variable renewables and storage is "both impractical and prohibitively expensive."[104] Because adding new natural gas generation is not consistent with some of the region's 100 percent clean policies, it is possible that renewable hydrogen could fill the gap by serving as long-duration energy storage and, when used to generate power with a turbine, a firm and dispatchable resource. This use case would likely compete, however, with contributions from the existing, carbon-free hydropower system and from developments of other innovative technologies, like enhanced geothermal or advanced nuclear, that could provide clean, dispatchable power in the decades ahead.

Retrofitting of existing natural gas plant turbines with ones that can run on a mix of natural gas and hydrogen, development of new hydrogen combustion electricity generating facilities, or retrofitting of existing natural gas plants with CCS technology are consistent with Oregon's clean energy policies. Oregon's clean electricity standard bill, House Bill 2021, passed by the Oregon Legislature in 2021, bans the construction of new generating facilities that burn natural gas, other fossil fuels, or fuels derived from fossil fuels unless the Energy Facility Siting Council (EFSC) determines that a new facility would not emit GHGs "into the atmosphere."[105] This means that EFSC could approve a new facility that combusted: 1) only fossil natural gas or renewable natural gas with CCS; 2) a mix of renewable or zero-carbon hydrogen and renewable natural gas with CCS; or 3) only zero-carbon or renewable hydrogen. This assumes that the facility would have NOx mitigation in place to capture and store those emissions from the combustion of hydrogen.

Additionally, HB 2021 allows for EFSC to approve amended site certificates for existing fossil facilities only if they would not result in a "significant" increase in GHG emissions from the facility; EFSC has defined "significant" in its administrative rules to mean three percent above the estimates used in the facility's most recently issued site certificate.[106] This means that EFSC could approve an amended site certificate for an existing natural gas plant if the plant was upgraded with a turbine that could combust a mix of natural gas and zero-carbon or renewable hydrogen, with or without CCS, as long as the expected GHG emissions did not increase by more than three percent.

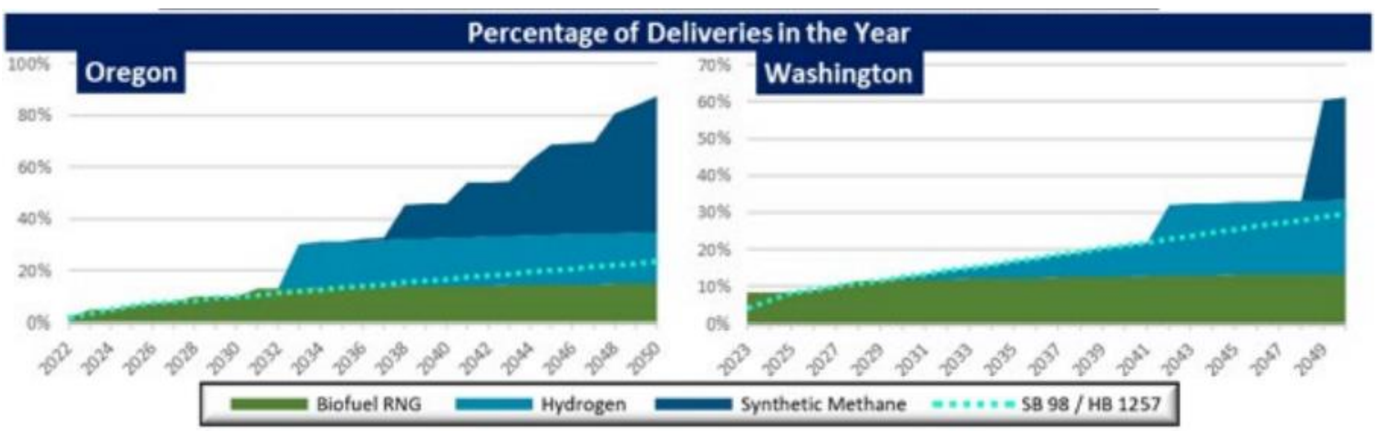
### *Natural Gas Pipeline Blending*

The strategy of blending renewable hydrogen into natural gas pipelines may be in use in Oregon in the near term. Oregon's Climate Protection Program (CPP) sets a cap on GHG emissions from regulated fossil fuel suppliers, including the state's three natural gas utilities. This emissions cap is reduced each year to decrease GHG emissions by 50 percent by 2035 and 90 percent by 2050. Natural gas utilities (and other covered entities) comply with the CPP by reducing their emissions, buying excess emissions allowances, or contributing funds to Community Climate Investments.

### NW Natural

NW Natural, the largest of Oregon's three natural gas utilities, modeled nine different portfolio options in its 2022 Integrated Resource Plan, all of which included hydrogen.[107] Scenario 1, called the Balanced Decarbonization scenario, represents what NW Natural considers to be a balanced approach to complying with GHG emissions reduction policies in Oregon and Washington. This scenario includes "a moderate amount" of natural gas use for heat pumps and dual-fuel heating systems and a conservative estimate of renewable hydrogen in the portfolio (see Figure 23). Across scenarios, renewable hydrogen is expected to become the cheapest clean resource beginning around 2030 and, once pipeline blending limits are reached around 2040, methanated renewable hydrogen becomes the cheapest resource. As discussed in Chapter 3, methanation is when hydrogen molecules react with CO2 in the presence of a catalyst to form synthetic methane and water.

**Figure 23: Modeled Deliveries of Compliance Resources in Oregon and Washington for Scenario 1 in NW Natural's 2022 IRP[107]**



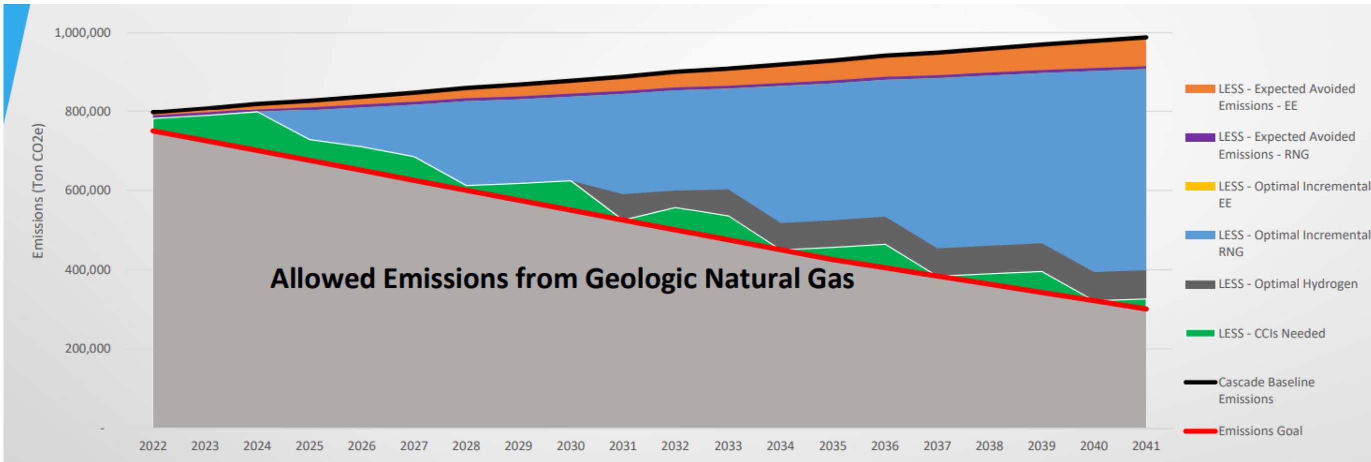

NW Natural is currently testing the blending of hydrogen into the natural gas pipeline at its Sherwood Operations and Training Center, starting with a blend of five percent by volume and incrementally moving up to 20 percent.

NW Natural is not focusing solely on renewable hydrogen, at least in the near term, and it has announced a partnership with Modern Electron to build methane pyrolysis infrastructure at its Central Portland facility, with a goal of being operational by 2023. This process would use natural gas and air to produce hydrogen and a solid carbon byproduct.[108]

### Cascade Natural Gas

Modeling from Cascade Natural Gas for the OPUC Natural Gas Fact Finding docket suggests that RNG will play a much larger role in the utility's CPP compliance than renewable hydrogen. For the base case scenario, Cascade shows "optimal incremental hydrogen" only playing a role in its supply starting in 2031, and then at a very small percentage (see Figure 24). The modeling only considers renewable hydrogen but the presentation notes that Cascade is also considering hydrogen from fossil feedstocks with CCS.

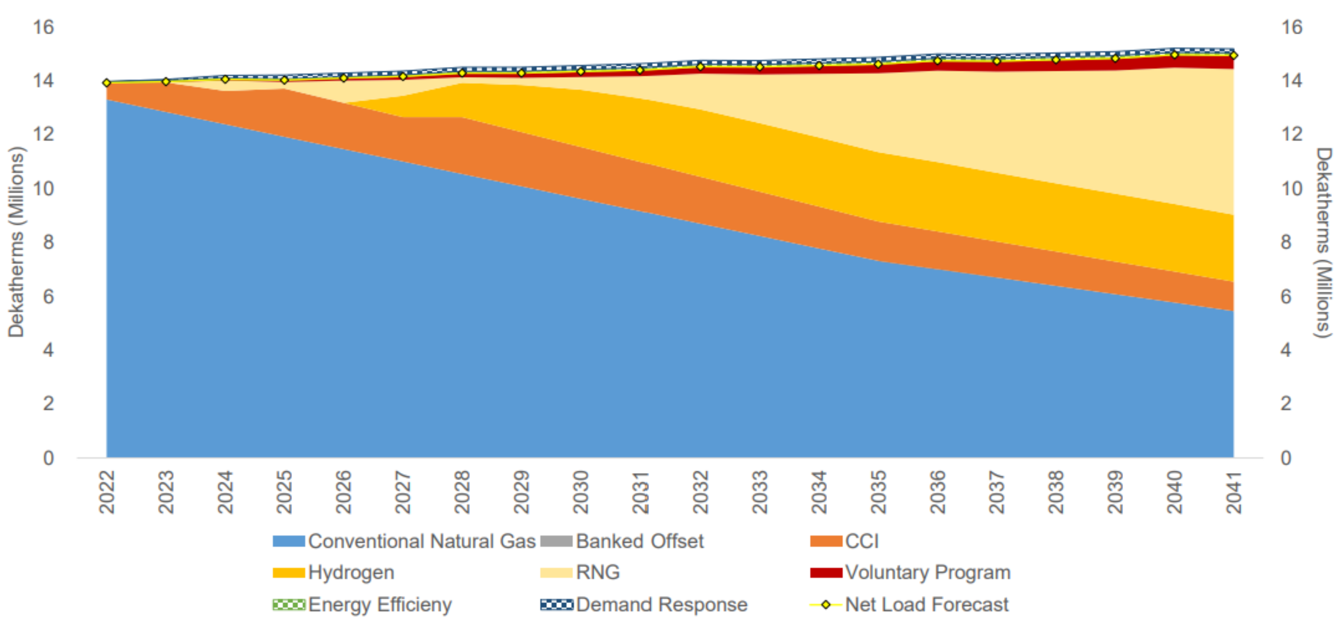
**Figure 24: Cascade Natural Gas Draft Supply Mix Forecast for UM 2178[109]**




## Avista

For its modeling for the Natural Gas Fact Finding docket, Avista provided a base case supply mix that includes renewable hydrogen starting in about 2026 (see Figure 25). Avista states in an FAQ[110] on its website that it is "watching and researching technologies… such as green hydrogen," and in a 2022 Request for Proposals seeking new generation resources, including hydrogen.[111]

**Figure 25: Avista Draft Supply Mix Forecast for UM 2178[112]**



# CHAPTER 6: OPPORTUNITIES FOR COUPLING RENEWABLE ELECTRICITY GENERATION AND RENEWABLE HYDROGEN PRODUCTION TO INCREASE RESILIENCY, PROVIDE FLEXIBLE LOADS

Adding larger shares of variable renewable electricity into the energy system increases the need for greater operational flexibility of the grid. Production of renewable hydrogen can help integrate more renewables in several ways: electrolyzers serving as flexible load and a sink for otherwise curtailed renewable generation; provision of grid services; replacing natural gas in power plants, especially peaker plants; and provision of long-duration energy storage and back-up power. However, to best take advantage of the benefits of electrolyzers, utilities will need to modify their approach to resource planning.

## Electrolyzers as Significant, but Flexible Loads

### *Future Electricity Demand from Electrolyzers*

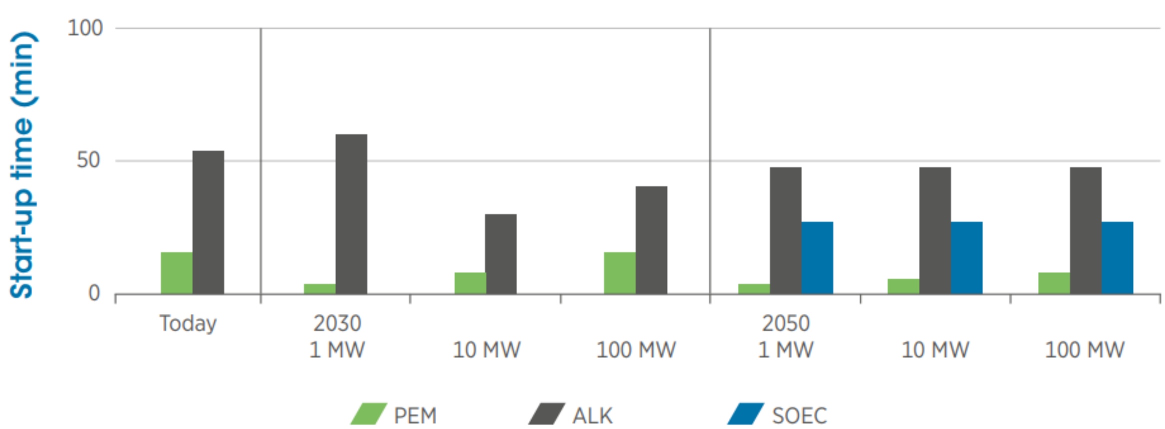
The Hydrogen Council estimates that meeting all global demand for hydrogen with renewable electrolytic hydrogen would require 10,000 GW of dedicated renewable capacity, or almost 29,000 TWh of energy, by 2050; electrolyzer capacity would have to exceed 600 GW by 2030 and reach about 5,500 GW by 2050.[113] While few analysts expect that *all* future hydrogen demand will be met with renewable electrolytic hydrogen or even that all renewable hydrogen will be produced using electricity, there is consensus that a great deal of renewable electricity will be needed to power electrolyzers if renewable hydrogen is going to be part of the decarbonization solution.

### *Electrolyzers as Important Flexible Loads*

Flexible loads are those that can have their demand for electricity ramped up or down quickly to respond to market signals or grid requirements. Flexible loads are important to the decarbonization of the grid in that they can increase the efficient use of variable renewable electricity, reduce system costs, and help reduce the need for fossil thermal generation.

Electrolyzers used to produce renewable hydrogen are responsive, flexible end-use loads. As shown in Figure 26, today's electrolyzers can start up quickly and can also ramp production up or down in a matter of seconds (for PEM electrolyzers) or minutes (for ALK electrolyzers).

**Figure 26: Current and Forecasted Electrolyzer Start-up Times[114]**



NREL and Idaho National Laboratory have been collaborating in a multi-year project to validate coordinating electrolyzers with renewable energy. The researchers outfitted a PEM electrolyzer stack with a front-end controller that exchanged data between the electrolyzer's internal controls and a modeled grid and computed a set point for revenue-optimizing performance. In testing the electrolyzer stack's remote commands related to ramping, utility demand response signals, and random variations, they found response times of under one second across the board.[115] In additional modeling and testing, they found that electrolyzers controlled by front-end controllers can enhance grid stability by limiting frequency and voltage deviations, and that fleets of electrolyzers with front-end controllers can provide a cohesive response to grid signals.

## Electrolyzers as Providing Grid Services

The ability of a single electrolyzer or a fleet of them to respond quickly to signals means they are well suited to provide the grid services that become increasingly important in an energy system dominated by variable renewable resources. It is important to note that these grid services can also be provided by other technologies, such as battery storage. Following are the grid and wholesale market services that controllable electrolyzers can provide:[115 116]

**Grid services** are functions that help maintain a reliable electricity grid. They include maintaining the proper flow of electricity, addressing imbalances between supply and demand, and they help the system to recover after events like blackouts.

**Peak Capacity Management** – Electrolyzers can ramp down consistently and reliably to minimize (or avoid) increasing critical peak loads within a specific region or location on the grid.

**Price Response** – Electrolyzers can ramp down consumption when energy market prices are high (i.e., when supply is otherwise constrained) and ramp up when energy prices are low (i.e., when sufficient supply is available).

**Transmission and Distribution Support** – Electrolyzers can respond quickly to ramp down demand to reduce transmission line congestion. If the electrolyzers have sufficient capacity, they can add load without encumbering the grid. The more load that can be added to a system without requiring new construction, the more the fixed costs of the system can be spread across the energy produced, which drives down the cost of electricity for other consumers.

**Distribution Voltage Management** – Electrolyzers can receive voltage deviation signals and adjust their net load.

## Electric Utility Planning for Electrolyzers in Oregon and the Northwest

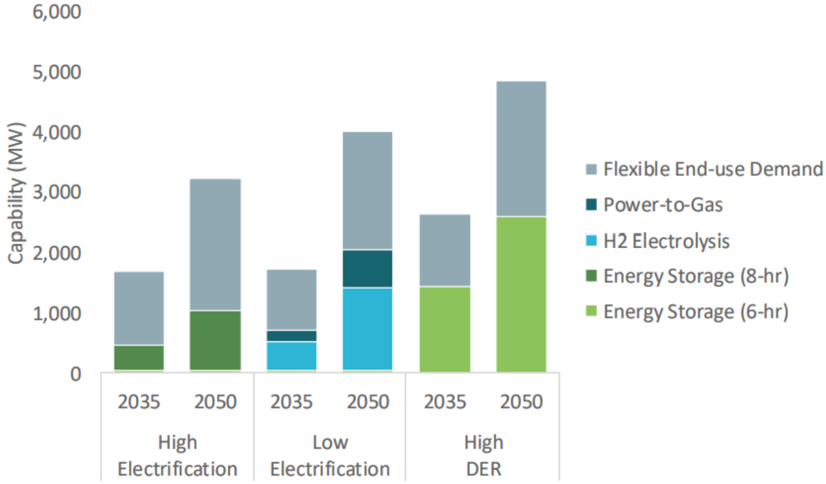
Looking forward, electric utility planning may need to be modified to reflect the properties of renewable hydrogen production, namely that it can serve as both as a flexible load and potentially as a generation resource. There are a handful of utility tariffs and rate schedules that can compensate electrolyzers for the benefits they provide to the grid, related to different demand response pathways or, indirectly, colocation pathways. Demand response refers to a deliberate change in a utility customer's electricity usage as a response to a change in price or a request from a utility or grid operator; sometimes customers give utilities direct control over some of their equipment in exchange for a more favorable rate.[117] Co-location refers to siting an electrolyzer directly with an electricity generating resource.

In a 2022 study of the costs of different pathways for producing hydrogen in California, NREL found that the least-cost option was using Southern California Edison's (SCE) real-time pricing tariff (a form of demand response). Among the three largest electric utilities – Pacific Gas & Electric, SCE, and San Diego Gas & Electric (SDG&E) – costs of producing hydrogen via electrolysis in Pacific Gas & Electric or SDG&E territory were markedly more expensive than in SCE territory, even using comparable tariffs.[118] However, even in utility territories where retail tariffs are expensive, like Pacific Gas & Electric, the study found that integrating electrolyzers with electricity markets by way of dynamic retail tariffs or direct wholesale market participation could help to reduce the cost associated with electrolytic hydrogen production. Additionally, co-locating electrolyzers with utility-scale wind or solar, especially in parts of the grid prone to low or negative wholesale electricity prices, can reduce production costs further.

In Oregon, both Portland General Electric and PacifiCorp offer interruptible load rate schedules to large commercial customers as well as time-of-use rates. Very few U.S. electric utilities offer tariffs that allow specific demand response rates for electrolyzers that account for the value of their fast response times and other benefits. As an example of one that does, Tacoma Power's electrofuel tariff, launched in 2021, allows the utility to curtail electricity demand from electrolyzers when necessary in exchange for a rate lower than its industrial rate.[119] Also in 2021, Arizona Public Service Company unveiled a similar electrolytic rate for Nikola Corporation.[120]

With respect to resource planning, ODOE is not aware of any Oregon electric utility specifically modeling electrolyzer demand as a load or as a flexible resource through their Integrated Resource Planning, though that might change in the next round of planning. PGE's 2018 Decarbonization Plan[121] states that long-term planning in the electricity sector will need to consider decarbonization efforts in other sectors that will increase demand for clean electricity, including electrolysis. One of the pathways modeled in the study includes 2,000 MW of electrolysis and relies on these electrolyzers and other flexible loads in place of battery storage for grid balancing (see Figure 27). As renewable hydrogen production grows in the Northwest, it is likely that both PGE and PacifiCorp will further assess the value of renewable hydrogen in their resource planning – as a flexible load and possibly as a resource for co-locating with other resources to reduce grid congestion.

**Figure 27: Balancing Resources Identified in the Three Pathways of PGE's Decarbonization Study[121]**



# CHAPTER 7: FORECASTED COSTS FOR RENEWABLE HYDROGEN AND EFFECT ON ADOPTION

One of the biggest barriers to the widespread adoption of renewable hydrogen is the cost as compared to fossil hydrogen, natural gas, and direct electrification – the cost of the renewable hydrogen itself as well as the infrastructure needed to store, transport, and use it. The US DOE Hydrogen Shot was launched in 2021 with a goal of reducing the cost of clean hydrogen, including renewable hydrogen, to $1 per 1 kilogram in one decade (referred to as "1 1 1"). This represents a cost reduction of 80 percent from current prices. While the Hydrogen Shot focuses on all low-carbon ("clean") hydrogen pathways and end uses, many of the funding streams related to the program will also help reduce the costs associated with renewable hydrogen. Recent federal legislation has allotted billions of dollars for renewable and low-carbon hydrogen deployment, including a total of $8 billion for Regional Clean Hydrogen Hubs, a production tax credit, and other funding for research and development. These recent legislative changes have the ability to greatly reduce the time needed to meet the Hydrogen Shot goal of $1/kg in ten years and also render many recent forecasts of renewable hydrogen prices outdated.

## Key Factors that Determine the Cost of Renewable Hydrogen

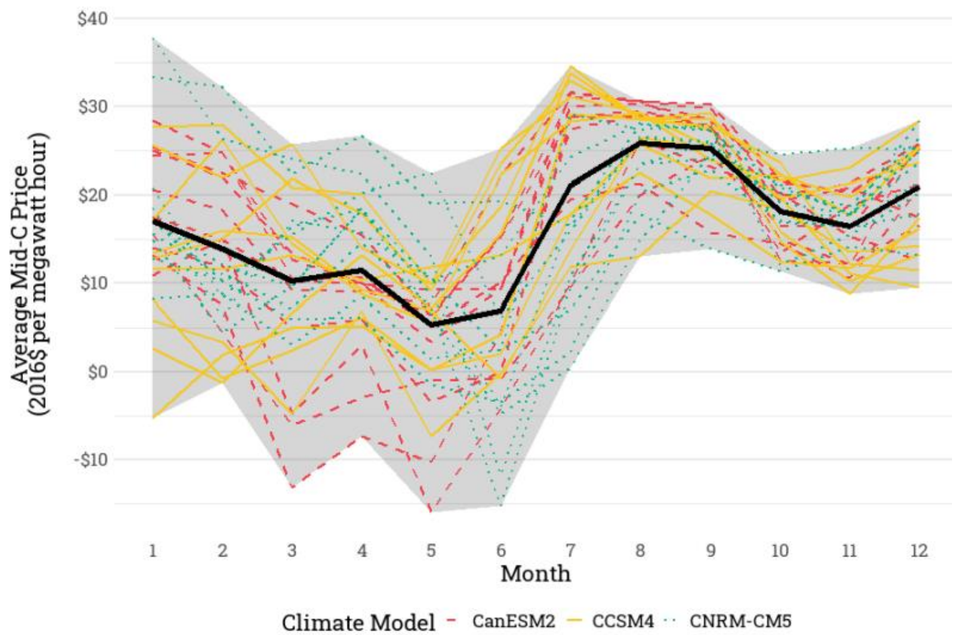
### *Renewable Electricity Costs*

**The largest single cost driver for renewable electrolytic hydrogen is the cost of renewable electricity, accounting for anywhere between 30-75 percent of production costs.**

The largest single cost driver for renewable electrolytic hydrogen is the cost of renewable electricity, accounting for anywhere between 30-75 percent of production costs.[122] [123] Operators of electrolyzer facilities can receive power in a number of ways, including: through the commercial or industrial rate schedules (depending on their electricity demand) of their incumbent utility; by contracting with an electricity service supplier; by building their own renewable generation facility; or a combination of these. While utility customers on a large commercial or industrial rate schedule are likely to pay more than the wholesale cost of electricity to cover things like transmission and distribution costs as well as peak pricing, wholesale costs are a useful proxy for understanding how future electricity prices in Oregon may affect the production of renewable hydrogen.

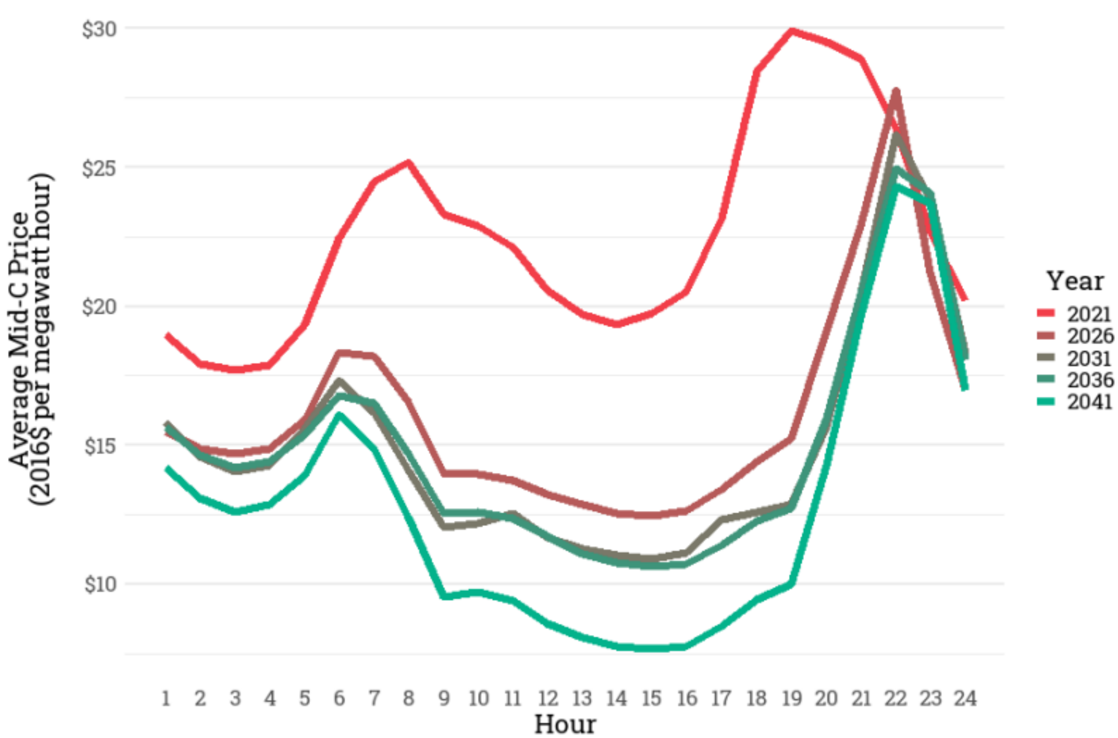
The 2021 Power Plan[63] provides estimates for the average wholesale cost of electricity at the Mid-Columbia hub based on various modeled hydro conditions (see Figure 28). The Mid-Columbia, often referred to as the Mid-C, is one of a handful of electricity trading hubs in the Western portion of the United States, and according to the NWPCC, it "represents an aggregation of the electricity market for the Northwest."[124] The 2026 price forecast shows the seasonality of electricity prices in the Northwest, with average expected prices dipping to a low of almost $5/MWh in May and rising above $25/MWh in August.

**Figure 28: 2021 Northwest Power Plan Forecast of 2026 Wholesale Electricity Prices Based on Climate Model Hydro Conditions[63]**



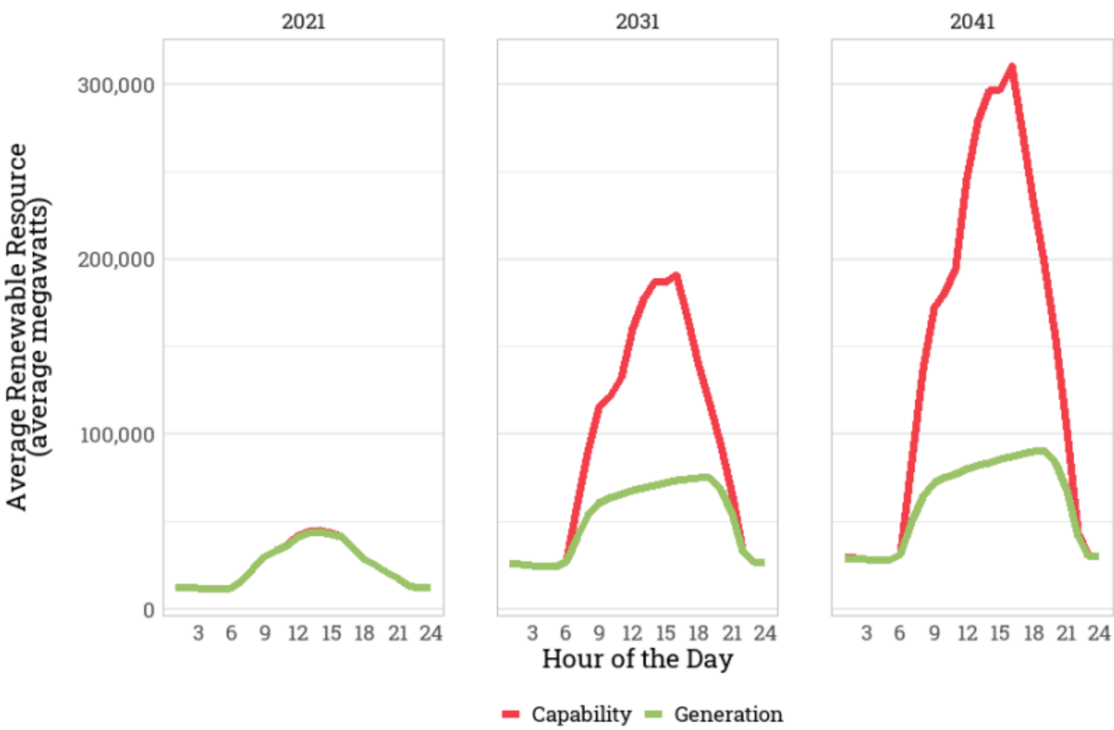

The 2021 Power Plan also includes a forecast for average hourly prices at the Mid-C, which demonstrates how wholesale prices can fluctuate during a 24-hour period. As shown in Figure 29, the shape of forecasted prices takes on the appearance of California's "duck curve" – the low prices shown in the late morning and afternoon for the Northwest are due to a high supply at that time of renewables, namely solar.

**Figure 29: 2021 Northwest Power Plan Forecast of Mid-C Average Hourly Wholesale Electricity Prices[63]**



While Figure 29 doesn't display any negative electricity prices,[v] the 2021 Power Plan identifies that the addition of inexpensive renewable electricity resources is already leading to low prices in the wholesale electricity market in the Northwest, particularly midday when solar electricity production is at its highest. Given the construction of resources that the Plan recommends – at least 3,500 MW by 2027 – the expectation is that low electricity prices could become more prevalent, including the potential for negative prices, and that there will be "substantial generation curtailment" as renewable electricity supply outstrips demand at certain times of the day and during certain seasons. Figure 30 shows the Plan's forecast for a substantial increase in average curtailed renewable generation (capability minus generation).

**Figure 30: Future Renewable Resources and Curtailment in the Western Electric Grid[63]**




Putting these forecasts from the 2021 Power Plan together, the expectation is for a lot more renewable electricity generating resources to come online, for wholesale power prices to fluctuate based on seasonal and diurnal factors, and for low and even negative electricity prices and possible curtailment of generation in the years to come. For the most part, this is good news for potential producers of renewable electrolytic hydrogen – more renewable electricity being produced, with hours or longer of that power being very low cost. However, electrolyzers cannot expect to run only when low-cost or zero-cost electricity that would otherwise be curtailed is available. One developer shared with ODOE that with today's costs, an electrolyzer installation would have to have a utilization rate of about 75-80 percent to justify the investment. One reason that plants become more expensive with lower utilization rates is that developers would have to install more storage for the renewable hydrogen to ensure

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[v] When wholesale electricity prices are negative, big end users of the electricity can essentially be paid to consume more power.

meeting customer demand – the timeline between production and offtake becomes an optimization challenge.

Another consideration is how much of the new renewable generation needed to meet the region's climate and clean energy goals will actually get built, and how much of that renewable electricity will be available for renewable hydrogen production. For example, the California Energy Commission expected that about 4,000 MW of new electricity generation resources would be online and available by the summer of 2022, but the reality was closer to 2,500 MW – 40 percent less. Much of this shortfall was due to supply chain constraints, but it demonstrates the challenges with quick deployment of resources.[125]

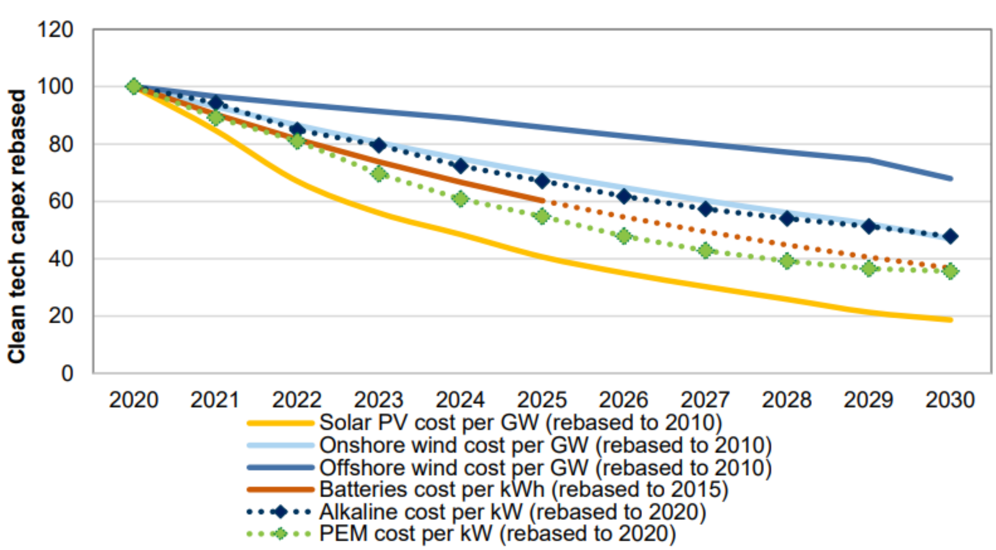
### *Electrolyzer Costs*

After electricity, the second biggest cost for producing renewable electrolytic hydrogen is the electrolyzer itself. Current costs for electrolyzers from leading manufacturers are between $650 and $900/kW. The rest of the capital expenses for a renewable hydrogen plant (including de-ionization, grid connection, and others) can bring the price of a plant up to between $1,000-$1,400/kW.[126] While these costs have come down quite a bit in recent years, electrolyzer costs benefit from economies of scale – which are building slowly as the market develops.

**After electricity, the second biggest cost for producing renewable electrolytic hydrogen is the electrolyzer itself.**

By the end of 2020, there was only about 0.3 GW of global installed electrolyzer capacity for producing green hydrogen; forecasts for installed capacity by 2030 range from 54 to 91 GW.[16 50] Average project sizes are also projected to scale up by more than 100 percent – from an average of about 2 MW in 2020 to 200 MW by 2025 and even GW scale by 2030. Goldman Sachs forecasts that, with the fast growth of the industry and attendant scalability, electrolyzer costs could fall by approximately 40 percent between 2020 and 2025 (see Figure 31).[50] Rethink Energy predicts a learning rate of about 11 percent for electrolyzers, which means that every time global installed electrolyzer capacity doubles, they expect that capital expenses will fall by 11 percent.[126]

**Figure 31: Forecasted Cost per kW for Electrolyzers and Renewables and kWh for Batteries[50]**



Recent announcements by electrolyzer manufacturers are bearing out these expected cost reductions. Italian manufacturer Enapter expects to reduce the cost of its anion-exchange electrolyzer by over 83 percent over the next three years from economies of scale and factory automation, while the Norwegian manufacturer Nel expects a 75 percent reduction in the cost of its ALK electrolyzers once its new automated factory is operational.[127] [128]

## Forecasted Costs of Renewable Hydrogen

Costs for renewable hydrogen are usually expressed as levelized costs, which includes the capital and operating costs of the production plant. Levelized costs give a fuller picture than upfront costs as they measure lifetime costs divided by energy production, taking into account the present value of the total cost of building and operating the production plant over its assumed lifetime. This allows a comparison between different generating technologies with different project sizes, capacities, lifespans, capital costs, risks, and returns.[129]

Recent federal legislation has provided about $22.5 billion in funding for clean hydrogen, which calls into question renewable hydrogen price forecasts made before the Infrastructure Investment and Jobs Act and the Inflation Reduction Act passed in November 2021 and August 2022, respectively. However, these earlier forecasts can still be useful in that they are likely much more conservative than what is now expected with today's policy landscape.

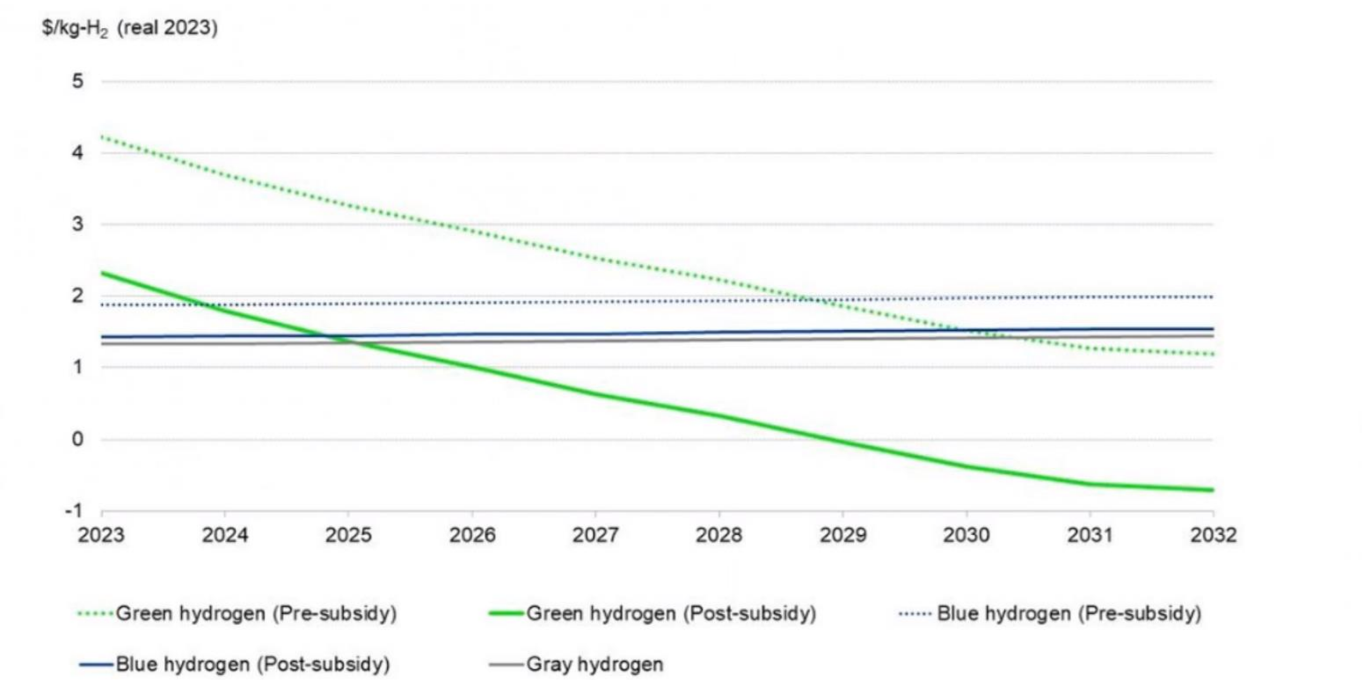
The Inflation Reduction Act includes a production tax credit (PTC) for hydrogen production that is below a certain carbon intensity threshold, which is expected to have an outsized effect on reducing the levelized cost of hydrogen in the United States. The PTC has a multiplier mechanism where producers can get a higher tax credit if they build their facilities within a certain timeframe and meet certain project wage and labor requirements. Those who produce the lowest carbon intensity hydrogen and trigger the multiplier can get up to $3 per kg of hydrogen (see Figure 32). Plug Power Inc., makers of fuel cells, suggested that the hydrogen PTC could halve the payback period for hydrogen production plants from 8-10 years to 4-5 years.[130]

**Figure 32: Hydrogen Production Tax Credit Amounts in Inflation Reduction Act of 2022[69]**

| Carbon Intensity Level per kg of Produced Hydrogen | Tax Credit Amount | 5x Multiplier |
|---|---|---|
| 4 kg of CO2e | $0 | $0 |
| 4-2.5 kg of CO2e | $0.12 | $0.60 |
| 2.5-1.5 kg of CO2e | $0.15 | $0.75 |
| 1.5-0.45 kg of CO2e | $0.20 | $1.00 |
| 0.45 kg of CO2e | $0.60 | $3.00 |

BloombergNEF analyzed[131] the effect of the hydrogen PTC on forecasts for the levelized cost of hydrogen in the U.S. and compared that to forecasts made before the Inflation Reduction Act passed (see Figure 32). On a levelized basis, BloombergNEF calculates that the PTC is worth about $1.91/kg and that it can bring the average cost of renewable hydrogen in the U.S. down to $2/kg by 2023 instead of 2029, as they'd previously forecast. Also, even though both renewable hydrogen and low-carbon "blue" hydrogen would benefit from the PTC, renewable hydrogen would reach cost parity with blue hydrogen much sooner according to this updated analysis – in about 2025 instead of 2029. The real headline, however, is that renewable hydrogen prices could go negative by 2030 when factoring in the PTC.

**Figure 33: Forecasted Effect of Production Tax Credits on U.S. Levelized Cost of Hydrogen[131]**




The Princeton ZERO Lab's preliminary analysis[132] of the climate and energy impacts of the Inflation Reduction Act finds that providing technologies like clean hydrogen production with access to robust deployment subsidies could lead to precipitous drops in costs similar to those of solar (about 90 percent) and wind (about 70 percent) since 2009.[133]

## The Cost of Renewable Hydrogen as Compared to Substitutes

Not only are the production, storage, and transport costs for renewable hydrogen key in increasing adoption of it, but it must also compete with alternatives in nearly every use case. For that reason, the issue of cost parity becomes important – when renewable hydrogen might fall to the same or lower price than these other options.

Having policies that provide a price on carbon, like Oregon's CPP, or policies that reward the use of alternate fuels, like the Clean Fuels Program, will help drive adoption of renewable hydrogen before it reaches cost parity with high-carbon or even low-carbon hydrogen from fossil fuels. In a 2020 report, BloombergNEF provided figures for the carbon price needed in 2050 to spur adoption of renewable hydrogen that cost $1/kg delivered to large users and $4/kg delivered to road vehicles.[134]

### *The Cost of Fossil Hydrogen*

Unless firms are required to switch from fossil hydrogen to low-carbon or renewable hydrogen or they wish to do so as part of corporate social responsibility or other initiatives, they will not do so until the cost of renewable hydrogen costs are close to parity with those of fossil hydrogen. According to Platts, the average monthly cost for hydrogen produced from steam methane reformation without CCS in the Northwest of the United States is $1.55/kg, while the average for renewable hydrogen produced from ALK and PEM electrolyzers is $4.02/kg and $5.21/kg respectively.[135] Given Oregon's climate and renewable energy goals, including the CPP, and the expectation that renewable hydrogen should hit cost parity with so-called grey hydrogen by about 2025 when considering the PTC, Oregon should expect to see users of high-carbon hydrogen swap it out for low-carbon or renewable hydrogen by 2025, if not earlier.

### *The Cost of Natural Gas and The Cost of Low-Carbon Hydrogen*

Not only has the cost of natural gas risen sharply in the past two years due to global factors, but Oregon also has policies in place, including the CPP and the Clean Fuels Program, that require an increase in low-carbon stationary and transportation fuels. There has been debate around whether the renewable hydrogen market can be built quickly enough to negate the necessity of an intermediate use of low-carbon fossil hydrogen made with CCS, with the expected lower cost of fossil hydrogen with CCS as compared to renewable hydrogen and the possible tight supply of renewable hydrogen initially cited as causes. While the Hydrogen Shot program includes funding for both types of hydrogen and the PTC also rewards both, there have not been any recent cost analyses of the production of low-carbon fossil hydrogen with CCS that account for the sharp increase in natural gas prices or Oregon's GHG reduction policies. For this reason, it is hard to forecast whether and how the price of renewable hydrogen will affect deployment as a substitute for natural gas or how competitive it will be with low-carbon fossil hydrogen with CCS.

### *The Cost of Electrification*

When determining whether renewable hydrogen will compete with electricity on cost as an end use, electricity will always win because it costs more to produce renewable hydrogen from electricity than using the electricity itself directly. For this reason, the choice of which fuel to use for each end use case will be driven more by existing infrastructure, access to the fuel, and technical limitations. While hydrogen has some advantages over electricity as a fuel for light-duty vehicles – range, speed of refueling – there is already high market penetration of battery electric vehicles and EV refueling infrastructure, and the fuel itself (electricity) will almost always be cheaper than hydrogen. However, for use cases such as heavy-duty long-haul trucking, where the weight of batteries is a negative impact, refueling times can be critical, and there is not yet wide deployment of charging infrastructure that can meet the needs of these large vehicles, hydrogen may hold decisive competitive advantages.

# CHAPTER 8: BARRIERS TO PRODUCTION AND CONSUMPTION OF RENEWABLE HYDROGEN IN OREGON

The markets for production and consumption of renewable hydrogen are in their infancy, both in Oregon and globally. For renewable hydrogen to become an affordable, available resource – to be fully commercialized – there are several barriers to address. These include high production costs, relatively low efficiency, creating simultaneous growth in both supply and demand, lack of dedicated infrastructure, lack of clarity in definitions and certifications, safety, resource requirements (water), a need for education, and challenges with ensuring there are no climate impacts.

## High Production Costs and Relatively Low Efficiencies

**Current renewable hydrogen costs are somewhere between two and three times those of fossil hydrogen.**

Current renewable hydrogen costs are somewhere between two and three times those of fossil hydrogen.[136] These higher costs are due in part to the costs associated with the electrolyzers themselves, the renewable electricity to power them, and the relatively low efficiency of the electrolysis process as compared to production of other fuels. With the funding from the Infrastructure Investment and Jobs Act and the Inflation Reduction Act, the costs of renewable hydrogen are expected to fall as the market scales up, electrolyzers begin to benefit from increased deployment and economies of scale, and developers take advantage of the PTC. As part of the scaling up of electrolyzer production, many analysts expect that the efficiency of electrolyzers will also go up. As part of its multi-year research, development, and demonstration plan, the US DOE Hydrogen and Fuel Cell Technologies Office has future targets for electrolyzer efficiency.[137]

## Creating Supply and Demand – the Chicken and Egg Problem

Renewable hydrogen can be described as a four-part system – production, distribution, storage, and end use. All four must develop at about the same time to ensure that producers have customers, customers have hydrogen, and that it can get from one place to the next safely. Currently, the price of renewable hydrogen inhibits demand. But for the price to come down, more renewable hydrogen production must be deployed to achieve sector learning and economies of scale. But it is difficult to get financing for building renewable hydrogen production because there's no demand. This is the chicken and egg problem.

There is not currently a local supply of renewable hydrogen in Oregon or the Northwest (though that is expected to change soon), and it is difficult to build demand for a product that doesn't exist yet locally. For example, in its 2021 Hydrogen Fuel Cell Electric Bus Feasibility Study, TriMet identified that unless it built its own hydrogen production facilities, it would have to have low-carbon or renewable hydrogen trucked in from out of state.[138]

## Lack of Dedicated Infrastructure for Renewable Hydrogen

As discussed in earlier chapters, there is no existing hydrogen Infrastructure in Oregon – no dedicated pipelines, no fueling infrastructure, no production of renewable hydrogen. Renewable hydrogen can be blended into existing natural gas pipelines, but only at volumes of up to about 20 percent before retrofits would be needed to pipeline materials, compression settings, and end use appliances. There is research and development being done on technology to extract hydrogen out of a natural gas pipeline once it's been injected, which would allow for using the natural gas pipeline system for transport of hydrogen. However, this technology has not been used at scale yet and so presently injecting hydrogen into a natural gas pipeline does not represent transportation of hydrogen, only displacement of natural gas.

## No Statutory Definition for Renewable Hydrogen, Lack of Tracking and Certifications

Oregon does not currently have a definition for renewable hydrogen in its statutes or administrative rules. SB 333 provides a definition for the purposes of this study – "hydrogen gas derived from energy sources that do not emit greenhouse gases" – but it would need to be expanded to provide clarity on what pathways are considered eligible for production of renewable hydrogen. With respect to tracking, renewable hydrogen can be tracked through the Oregon Clean Fuels Program or for inclusion in the natural gas pipeline system as per SB 98 (2019), but there are few current tracking systems to trace renewable hydrogen and its ultimate consumption for other end uses. Without a tracking system in place, it is possible that there could be negative interactions with other policies, such as double counting of attributes with the RPS.

## Safe Handling

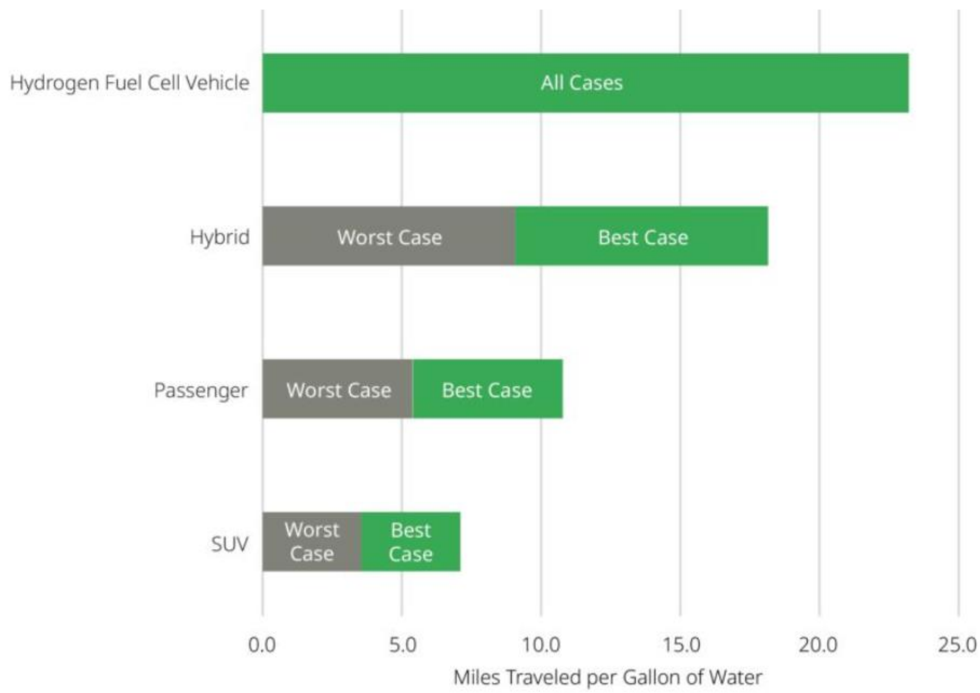
Hydrogen has been handled safely in a number of contexts for years. However, the properties of hydrogen require approaches that differ from those for handling other fuels. For example, hydrogen can ignite more easily than gasoline or natural gas, and for this reason, safe design of hydrogen systems requires adequate ventilation as well as specially designed leak detection sensors. Some of Oregon's safety and building codes may need to be updated to ensure that any on-site production, storage, or use of hydrogen is done so safely.

## Water Requirements

According to the [Fifth Oregon Climate Assessment](), an average of 37 percent of Oregon experienced drought of at least moderate intensity between 2000 and 2020, with another 7 percent experiencing extreme drought.[139] If climate change continues unabated, it is likely that much of the Western region of the country, including Oregon, will enter (if not already there) a state of perpetual drought.[140]

Producing renewable hydrogen via electrolysis requires a minimum of 9 kg of water for every 1 kg of hydrogen produced, with additional water needed for cooling and maintenance.[141] However, to put this into perspective, one gallon of water would be necessary to produce enough gasoline to travel about seven miles in a typical SUV or about 10.7 miles in a typical passenger vehicle. That same gallon of water could produce sufficient hydrogen for a hydrogen FCEV to travel about 23.2 miles (see Figure 34).

**Figure 34: Miles Traveled per Gallon of Water Used to Produce the Vehicle's Fuel**[142]

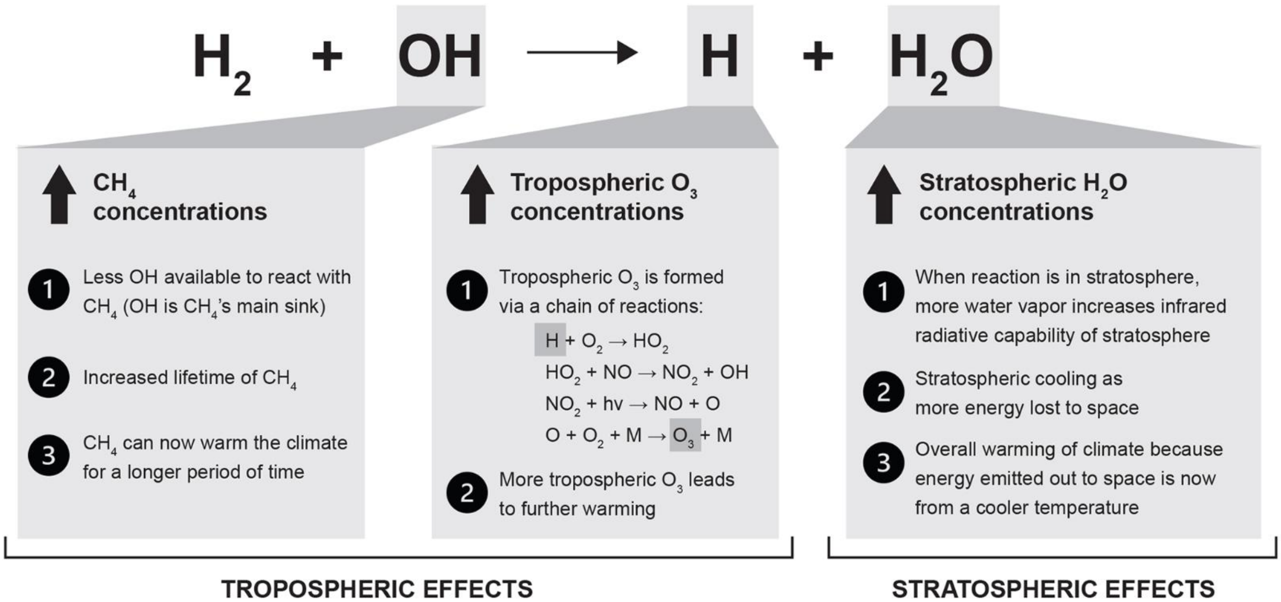



While the water use of renewable hydrogen production is less than needed for the extraction and processing of fossil fuels, it is still an issue of concern raised by some stakeholders during the development of this study. In place of freshwater, it is also possible to run electrolyzers with desalinized water or recycled water. For example, Plug Power is building a new renewable hydrogen plant along with a new wastewater treatment plant in Mendota, CA, which will supply recycled water for the hydrogen production.[143]

## GHG Emissions Concerns

Hydrogen is considered an indirect GHG in that when it escapes into the atmosphere it is oxidized and leads to increasing concentrations of direct GHGs in the troposphere and the stratosphere (see Figure 35). Given how small the hydrogen molecule is, it can more readily escape from infrastructure such as pipelines and storage vessels than larger molecules, like methane. Recent studies have suggested that the climate benefits of using renewable hydrogen to replace fossil fuels will depend, in part, on ensuring that leaks are mitigated to the extent possible. One study on the climate consequences of hydrogen found that renewable hydrogen use can range from more than a 95 percent reduction in climate impacts from fossil fuels to only 85 percent for leakage rates of one percent and 10 percent, respectively.[144]

**Figure 353: Effects of Hydrogen Oxidation on Atmosphere Greenhouse Gas Concentrations and Warming**[144]




## Need for Education

Even though renewable hydrogen is currently enjoying a period of incredible buzz, many people who are not closely following energy news likely don't know a lot about both the advantages and the disadvantages of producing and consuming renewable hydrogen as part of a decarbonization strategy. The US DOE Hydrogen Program addresses the general lack of awareness of hydrogen with education programs aimed at key audiences like state government, safety and code officials, potential commercial end users, and the general public.[145] Few studies examining social attitudes toward hydrogen or renewable hydrogen exist but there are models of the mental and social barriers that can arise when people are presented with new, unknown technologies, including energy technologies.[146] A recent UK study suggests that acceptance of hydrogen in general will depend on whether "consumers view it as an economical, reliable, efficient, and fair technology," as well as whether it is safe and lives up to its climate impact promises.[147]

# CHAPTER 9: RECOMMENDATIONS

Renewable hydrogen can play an important role in Oregon's decarbonization efforts by decarbonizing otherwise hard-to-abate sectors – those that cannot easily or cost-effectively be electrified and/or do not have other clean options. However, the scale of its role will be determined not only by the market but also by actions taken at the state level. Following are recommendations related to how to determine what role renewable hydrogen should play in Oregon's clean energy transition and how to support its development and use.

## 1. Determine the Appropriate Role for Renewable Hydrogen in Oregon

### *A State Energy Strategy for Oregon*

Policymakers can help determine the appropriate role for renewable hydrogen in supporting state decarbonization efforts. This evaluation could be part of a statewide energy strategy, one that enumerates and balances the trade-offs associated with decarbonization actions – such as cost, timing, land use, health and safety, wildlife, and many others. This would be a helpful first step to inform the conversation about renewable hydrogen's appropriate role within that broader strategy.

### *Define Renewable Hydrogen*

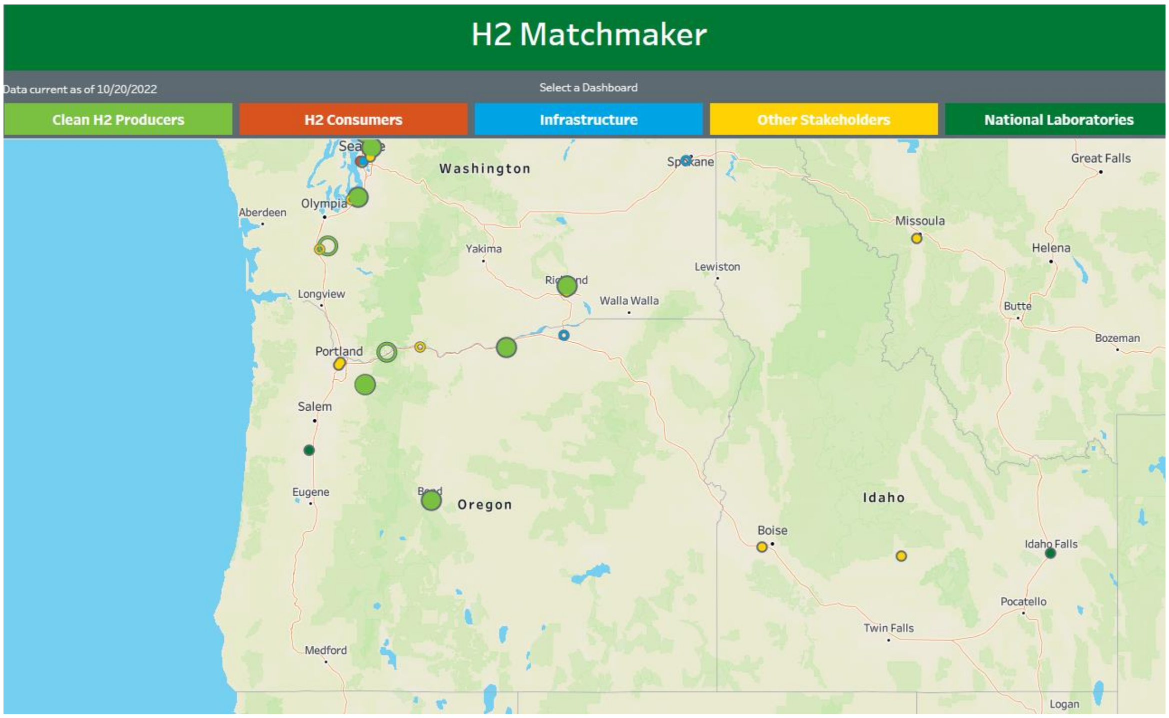
As part of developing a state energy strategy, Oregon should codify a definition for renewable hydrogen that clearly differentiates between hydrogen, renewable hydrogen, and low-carbon (or clean) hydrogen. Policymakers may determine that both renewable hydrogen and low-carbon hydrogen have roles to play in the state's decarbonization strategy, and if so, it should be clear how those roles will differ, if at all. Any definition of renewable hydrogen should make explicit whether and how biomass, biogas, and biomethane feedstocks are eligible given the GHG emissions associated with the pathways for producing hydrogen from them. In developing these definitions, care should be taken to ensure that there are not unanticipated effects on other policies in place, such as the Clean Fuels Program.

### *More Data about Hydrogen in Oregon*

As discussed in the report, getting data about current hydrogen use in the state is challenging. Many commercial and industrial companies consider this to be confidential information that, if exposed, could provide insight into their specific business practices. ODOE suggests that the state consider directing an agency with authority to require disclosure of this information to work, alone or in collaboration with ODOE, on a more in-depth inventory of current hydrogen use in the state. Further, the state should seek out more techno-economic analysis of different hydrogen technologies and end uses to better provide confidence for those who wish to enter the nascent hydrogen market in the Northwest.

Additionally, there is no centralized repository of information about potential renewable hydrogen projects in the state. The Renewable Hydrogen Alliance tracks projects they are aware of on a publicly available online map; Business Oregon sometimes receives inquiries about available resources for potential projects; ODOE's Siting Division fields requests for more information about siting requirements for facilities seeking to produce or to consume hydrogen; etc. It would be valuable to have all of these disparate sources of information feed into a single tool or tools so that decision-makers and stakeholders could see at a glance the scope of interest in renewable hydrogen in Oregon and potential hot spots for development or use. US DOE's H2 Matchmaker online resource allows potential hydrogen suppliers and end users to self-identify so that they can identify potential collaborators. Figure 36 shows the H2 Matchmaker interactive map with self-identified Oregon interests as of October 10, 2022.[148] Oregon could encourage those with interests in renewable hydrogen to use the tool to better help identify business development opportunities or it could serve as the basis for a future Oregon-specific resource.

**Figure 36: US DOE H2 Matchmaker Interactive Map (Beta Version)[148]**




## 2. Build the Oregon Renewable Hydrogen Roadmap

Once Oregon decisionmakers have considered what role renewable hydrogen should play in the state's decarbonization strategy and how renewable hydrogen markets are developing in the region, development of a roadmap to support both production and consumption of renewable hydrogen in the state will help identify goals and actions to achieve necessary production and consumption milestones. The roadmap should be developed in close collaboration with diverse Oregon stakeholders.

### *State Leadership and Regional Collaboration*

Oregon should consider establishing a multi-agency workgroup of state and local government representatives with expertise in decarbonization, GHG accounting, renewable energy, renewable hydrogen, permitting and siting, transportation, and utility regulation that can collaborate with one another and with other states in the region on addressing the multi-sectoral opportunities and barriers associated with renewable hydrogen.[19] This workgroup should engage with environmental justice and equity advocates, labor unions, and Tribal governments to ensure that actions related to renewable hydrogen center the safety, health, and equity of frontline communities.

In-state collaboration would provide Oregon-specific details for a renewable hydrogen roadmap and could also identify opportunities to leverage state, federal, and private investment in new projects. Regional outreach would be valuable for sharing best practices, setting harmonized requirements related to tracking and certification of environmental attributes, and identifying opportunities to develop complementary projects, such as those related to shared interstate corridors. Modeling of the electric, gas, transportation, water, and waste sectors at a regional level can further identify opportunities to coordinate individual state policies.[19]

### *Identify Key Sectors, Priorities, and Strategies*

A renewable hydrogen roadmap should include any priority sectors for support, especially those where decarbonization is especially expensive and/or not amenable to direct electrification. Individual sectors may benefit from their own roadmaps within the state energy strategy and/or the renewable hydrogen roadmap.

### *Address Policy and Regulatory Requirements*

Oregon should continue to assess its policies and regulations to see where new legislation or updated administrative rules might be necessary to support the desired level and speed of renewable hydrogen deployment. For example, in its Green Hydrogen Guidebook, The Green Hydrogen Coalition recommends strategies for the electric sector that include electrolyzer procurement targets and adoption of incentives or utility tariffs that compensate electrolyzers as flexible loads for grid support.[19]

### *Create or Adopt a Certification and Tracking System*

According to RMI, to achieve meaningful GHG reductions from the use of renewable (or low-carbon) hydrogen, "analytically sound and enforced thresholds for qualification" are critical.[149] Any carbon accounting framework for renewable hydrogen must consider the full lifecycle of GHG emissions, not just those associated with production. Oregon should consider the federal carbon intensity threshold that only accounts for the emissions associated with production to be a floor, not a ceiling. Should Oregon choose to require proof of additionality for the associated renewable electricity, that would need to be part of the certification process.

Another aspect for consideration is how renewable hydrogen will be tracked as it makes its way from the point of production to the point of consumption. For the Oregon Clean Fuels Program, an approved pathway for a fuel must include the transportation emissions associated with moving it to the end user. However, the voluntary renewable natural gas programs allowed by SB 98 (2019), which can include renewable hydrogen, uses a "book and claim" approach where the molecules are assumed to be delivered if they are injected into an interstate natural gas pipeline system at some point. Oregon should collaborate with other Western states on a certification and tracking system for the region to avoid patchwork requirements that hinder market development.

Western states should also consider *who* should handle the tracking. For renewable electricity eligible for state RPS programs, the Western Renewable Energy Generation Information System, or WREGIS, creates and tracks all renewable energy certificates for Western states.[vi] The Midwestern Renewable Energy Tracking System – the WREGIS for midwestern states – chose to build out a tracking system that could be used by any state to track renewable natural gas or renewable hydrogen that is injected into an interstate natural gas pipeline.[150] Oregon and other Western states should consider a certification system that can accommodate all end uses of renewable hydrogen; a tracking system could be separate from those already in place for the Clean Fuels Program or SB 98 for end uses not related to pipelines or transportation, if necessary.

## 3. Ensure Safety and Equity

Development of a new market offers an opportunity to redouble commitments related to energy safety and environmental justice. Any policies or programs related to renewable hydrogen that Oregon decision-makers create should incorporate best practices around safety and equity.

### *Establish Codes and Standards*

Oregon should establish new codes and standards as necessary to ensure the safe handling and use of renewable hydrogen, including those related to FCEV fueling and repairs, pipeline injection, storing and transport, appliances, and others. US DOE's Hydrogen Program has a codes and safety sub-program, which works with scientists, industry experts, code officials, and others to develop new codes and standards covering domestic and international hydrogen supply chain activities.[151] The Hydrogen and Fuel Cell Technologies Office of US DOE also serves as a clearinghouse for tools, databases, and training materials related safety, codes, standards, and permitting related to hydrogen.[152]

### *Workforce Programs, Labor Standards, and Equity*

In Oregon and nationwide, there are emerging programs designed to address historical and economic inequities, especially as relates to energy and related pollution. In his first weeks in office, President Biden established the Justice40 Initiative, a government-wide effort to ensure that at least 40 percent of the overall benefits from Federal investments in climate and clean energy accrue to disadvantaged communities. In its Regional Clean Hydrogen Hubs Funding Opportunity Announcement, US DOE requires that applicants submit a Community Benefits Plan that ensures Federal investments in hydrogen hubs advance community and labor engagement; investment in the American workforce; advance diversity, equity, inclusion, and accessibility; and contribute to the Justice40 Initiative.[153]

Washington state passed the Healthy Environment for All (HEAL) Act in 2021 to eliminate environmental health disparities and more equitably distribute health and environmental benefits by incorporating environmental justice work into the work of seven state agencies. In Oregon, the Environmental Justice Task Force was established in 2007 with Senate Bill 420, and then evolved into the Environmental Justice Council in 2022 with House Bill 4077. In 2021, two bills passed establishing requirements for equity impact statements for agency budgets and rulemakings (House Bills 2167 and 2353). And in 2017, the Oregon Just Transition Alliance was formed by local environmental justice organizations to build a statewide movement to further environmental justice in Oregon.[154] In 2020, the group launched a

[vi] WREGIS creates and tracks renewable energy certificates associated with renewable electricity produced in states located in the Western Electricity Coordinating Council.

listening tour to hear from 200 frontline community leaders; this feedback became the basis for the Alliance's 10 Pillars for an Oregon Green New Deal.[155]

With the likelihood that at least some of the Federal funding earmarked for renewable or clean hydrogen in the IIJA and in the IRA may come to Oregon, there is an opportunity for ODOE and other agencies to ensure that any state programs related to renewable hydrogen adhere to, and when possible, surpass, the requirements of the Justice40 Initiative. Additionally, the 10 Pillars for an Oregon Green New Deal can also help guide development of renewable hydrogen programs that help center workers in the transition to a low-carbon economy and advance workers' rights, safety, and the equitable distribution of jobs.

### *Education*

Oregon universities, community and technical colleges, and labor partners offer a wide array of educational programs that include pre-apprenticeships, apprenticeships, internships, and academic degrees. For example, the University of Oregon's Industrial Master's Program includes hydrogen curriculum and is currently placing between 25-30 graduates per year. As the hydrogen economy continues to grow, Oregon should build upon its existing workforce and economic development resources to ensure that Oregonians are well-positioned to take advantage of emerging opportunities.

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