



Hydrogen Opportunities in a Low-Carbon Future

An Assessment Of Long-Term Market
Potential in the Western United States

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Table of Contents

Executive Summary	1
Study Purpose	1
Approach and Key Findings	3
Uncertainties and Study Limitations	9
Differences Between this Study and E3's Study on the Challenge of Retail Natural Gas in California's Low Carbon Future	10
1 Introduction	12
1.1 Overview and Project Questions	12
1.2 Policy Landscape	13
1.3 Scenario Design Philosophy and Modeling Approach	15
1.4 Western U.S. PATHWAYS Model	15
1.5 Power Sector Modeling Approach	18
2 The Costs of Hydrogen Production	20
2.1 Hydrogen Production Methods	20
2.2 Hydrogen Production Costs	21
3 Hydrogen Outlook in the Power Sector	24
3.1 The Challenge with Meeting Deep Decarbonization Targets	24
3.2 Modeling a High Renewables Future in the West	25
3.3 Renewable Curtailment	27
3.4 Levelized Costs of Storage in the WECC	29
3.5 Potential Market Revenue for "First-Mover" Long-Duration Hydrogen Storage Projects	35
3.6 Potential Hydrogen Market Size	37
3.7 Potential Role of Gas Plants in Hydrogen-Fueled Power	40

4 Hydrogen Outlook in Transportation	42
4.1 Hydrogen in Transportation Today	42
4.2 Pump Price Comparison	42
4.2.1 Light-Duty Vehicles	42
4.2.2 Heavy-Duty Vehicles	44
4.3 Breakdown of Pump Price	46
4.4 Outlook for Hydrogen in Transportation	48
5 Hydrogen's Outlook in Industry	51
5.1 Hydrogen in Industry Today	51
5.2 Outlook for Hydrogen in Industry	52
6 Hydrogen's Outlook in Buildings	55
6.1 Space Heating in the West Today	55
6.2 Outlook for Hydrogen in Buildings	56
7 Hydrogen Supply Chain Overview	58
7.1 Mapping of the Current and Future Supply Chain	58
7.1.1 Production	59
7.1.2 Transportation	59
7.1.3 Storage	61
7.2 Centralized versus Distributed Storage Methods	63
8 Conclusions	64
9 Appendix	66
9.1 Additional Results	66
9.2 Comparison to CEC Retail Gas Study	71
9.3 E3's High Renewable Electricity Price Forecast in Aurora	73

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This report has been prepared by E3 for ACES, a joint development project between Mitsubishi Hitachi Power Systems Americas, Inc. and Magnum Development, LLC. This report is separate from and unrelated to any work E3 is doing for the California Public Utilities Commission. While E3 provided technical support to Mitsubishi Hitachi Power Systems Americas, Inc. and Magnum Development in preparation of this report, E3 does not endorse any specific policy or regulatory measures as a result of this analysis. The California Public Utilities Commission did not participate in this project and does not endorse the conclusions presented in this report.

Acronyms

AEC	Alkaline Electrolyzer
BEV	Battery Electric Vehicle
CCS	Carbon Capture and Storage
CEC	California Energy Commission
DOE	U.S. Department of Energy
DR	Demand Response
EE	Energy Efficiency
GHG	Greenhouse Gas
HFCV	Hydrogen Fuel Cell Vehicle
Li-ion	Lithium-ion
LCFS	Low Carbon Fuel Standard
PEM	Proton Exchange (or Electrolyte) Membrane
RPS	Renewable Portfolio Standard
TMT	Thousand Metric Tons
MMT	Million Metric Tons
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolyzer
WECC	Western Electricity Coordinating Council

Executive Summary

Study Purpose

The potential for hydrogen to serve as a source of zero-carbon energy across a wide range of applications has generated significant attention, given decarbonization targets across the globe and the increasingly urgent need to mitigate the worst impacts of climate change. Within this backdrop, Energy and Environmental Economics, Inc. ("E3")¹, an industry-leading consultancy, was retained by Mitsubishi Hitachi Power Systems Americas, Inc. (MHPS) and Magnum Development, LLC (Magnum), to provide an evaluation of the potential opportunities for hydrogen in the Western United States under a low-carbon future.

MHPS is a leading gas turbine manufacturer based in Orlando, Florida. This analysis stems from MHPS and Magnum's 2019 announcement of the Advanced Clean Energy Storage (ACES) project. The project proposes to utilize renewable electricity to produce hydrogen via electrolysis. That hydrogen would be stored in a network of underground salt dome caverns located near Delta, Utah. ACES's stored hydrogen has the potential to provide zero-carbon fuel to generate electricity via thermal cycle power plants or fuel cells.

E3's investigation focused on four broad research questions:

- + What are the most viable hydrogen production methods, based on expected future cost trajectories?
- + What is the market outlook for hydrogen across sectors in the Western United States under a deep decarbonization future?
- + What is the potential role of hydrogen as a long-duration storage medium in a deeply decarbonized Western electricity system?
- + What does the hydrogen supply chain in the West look like today, and how may this supply chain evolve in a deep decarbonization future?

¹ E3's work shapes policy, market design, and strategy on a number of energy-related topics in many jurisdictions both in the U.S. and overseas. In addition to project developers and leading investors, E3's diverse client base includes public agencies, utilities, system operators, and large energy users. For more about E3 visit www.ethree.com.

To evaluate these questions, E3 relied on its extensive experience evaluating energy markets and decarbonization strategies across the West, particularly in California and the Pacific Northwest. This work has demonstrated the broad energy transformations needed to achieve economy-wide deep decarbonization goals, highlighting the importance of: 1) energy efficiency and conservation in all sectors, 2) increased reliance on zero-carbon electricity, and 3) the development of new, zero-carbon fuels.

Several Western states, including California, Oregon, Washington, Colorado and Montana, are all driving towards deeper and more ambitious climate goals. In 2018, California Executive Order B-55-18 called on the State to achieve carbon neutrality by 2045, and SB 100 requires the State to meet 100% of retail sales with zero-carbon electricity by 2045. In Washington, the Clean Energy Transformation Act, passed in 2019, also calls on the electricity sector to supply 100% of retail sales with zero-carbon electricity by 2045. Continued commitment and achievement of these deep decarbonization targets will be essential to the development of the hydrogen industry. Without a clear economic and policy case for decarbonization, the role of hydrogen is expected to remain limited. This analysis focuses on the potential role of hydrogen in a low carbon, high renewable future – in line with the most ambitious existing state policy targets in the West.

Approach and Key Findings

E3 evaluated a low-carbon, high renewables future in the West using two E3 models, PATHWAYS (for the Western U.S.) and RESTORE, which have been used by state agencies, utilities and stakeholders to examine questions related to deep decarbonization strategies. While both models evaluate low carbon futures in the West, the models differ significantly in their structure and assumptions. Thus, E3's analysis of hydrogen's potential in buildings, industry and transportation is not perfectly comparable with its analysis of the power sector. This process and the key market outlook findings are reflected at a high level in Figure ES-1.

The PATHWAYS model, an economy-wide GHG accounting tool, is used to create economy-wide decarbonization scenarios for the West. The model is an infrastructure-based stock rollover model that has been used to design a range of plausible strategies to achieve deep decarbonization. PATHWAYS is a scenario planning tool to explore deep decarbonization futures based on what is currently known about costs, technical potential, policy incentives and barriers, and other factors. For this project, E3 developed three deep decarbonization scenarios for the West, including:²

- + **Mid-Hydrogen Scenario** reflects a future in which hydrogen plays a moderate role in heavy-duty transportation and supports some limited industrial applications. This scenario is built to be consistent with a world in which the West achieves economy-wide 80% reductions relative to 1990 by 2050. In this worldview, most decarbonization arises through electrification of transportation and building end uses. The industrial sector contributes less to overall economy-wide decarbonization, given the relatively greater cost and challenges with decarbonizing this sector. In transportation, hydrogen is used in freight applications where electrification might not be as viable.

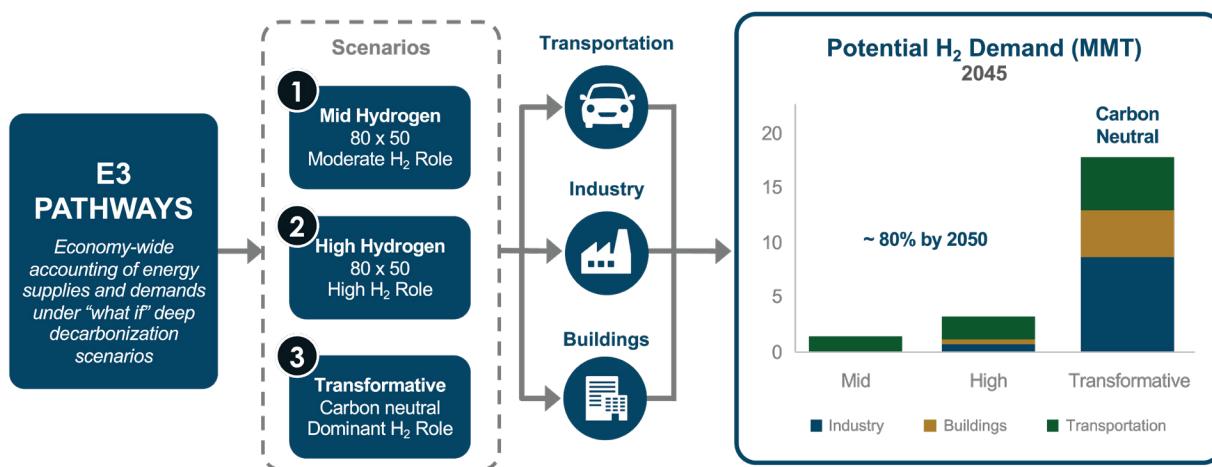
² We note that these PATHWAYS scenarios do not explicitly model the electricity sector, given this analysis is performed separately in RESTORE. Instead, this sector is assumed to achieve an exogenously set deep decarbonization emissions target.

- ⊕ **High-Hydrogen Scenario** reflects a future in which hydrogen realizes much of its technical potential in all sectors with moderate requirements for supporting policy and infrastructure upgrades. This scenario is also built to be consistent with a future in which the West achieves economy-wide 80% reductions relative to 1990 by 2050, but reflects a worldview where lower costs and other potential incentives lead to significantly greater hydrogen usage. In this scenario, hydrogen continues to be a key decarbonization strategy in heavy-duty freight transportation, but is also used within some industrial processes, and in some residential and commercial buildings located in the colder, Northern regions of the Western U.S. For these Northern regions, hydrogen is blended into the existing natural gas pipeline at up to 7% (by energy), in order to avoid triggering significant pipeline or end use device infrastructure upgrades that would be required to achieve higher blends of hydrogen in the gas distribution pipelines.
- ⊕ **Transformative Scenario**³ reflects a future in which hydrogen has a substantial presence in transportation, buildings, and industry, assuming commensurate policy drivers and enabling infrastructure. This scenario is consistent with a world in which the West achieves decarbonization consistent with a “net zero” carbon outcome, in line with existing policies in several states. This scenario assumes major upgrades in natural gas pipelines across the Northern West to accommodate 100 percent hydrogen blend in the distribution pipeline. Hydrogen is used for heating in Northern, colder climates, but building electrification is still the major decarbonization strategy across Southern, warmer climates in the West. In heavy duty freight and industry, hydrogen is used as the dominant decarbonization strategy, with relatively less amounts of electrification used as well.

³ We note that the transformative scenario does not assume that a global, or continental U.S., hydrogen supply chain exists. This scenario is “transformative” by enabling hydrogen to be available broadly in the West (i.e., not limited by pipeline blending). However, for this study, we do not assume that hydrogen produced in locations with extremely good renewable electricity production capabilities, such as the Atacama Desert, is imported into the U.S., nor does it assume that the desert Southwestern U.S. becomes a production hub for hydrogen to be used outside the West.

These scenarios were designed to create estimates of the potential market size for hydrogen in the future. The costs of the scenarios were not developed or compared, nor was the use of hydrogen across energy demand sectors optimized. These scenarios can be thought of as distinct world-view futures, of what might be needed to achieve a given carbon reduction target. These scenarios are not forecasts of what is likely to happen given current policy or technology trends. The total final hydrogen demand in 2045 estimated in these scenarios is shown in Figure ES-1, reported by sector in million metric tons (MMT).

Figure ES-1: Approach to analyzing the potential role of hydrogen in buildings, industry and transportation, and results for 2045 in million metric tons H₂ in the West.



This study separately assessed the potential for hydrogen in the power sector, investigating the total economic market potential for long-duration storage as well as the market opportunity for a “first of its kind” 1000 MW hydrogen storage project. To perform the power sector analysis, E3 first used its proprietary market price forecasts for the West, based on E3’s High RPS scenario forecast. The market price scenario represents the view that higher renewables will be achieved in all jurisdictions, including attainment of various 100% clean energy sales targets that are currently legislated.

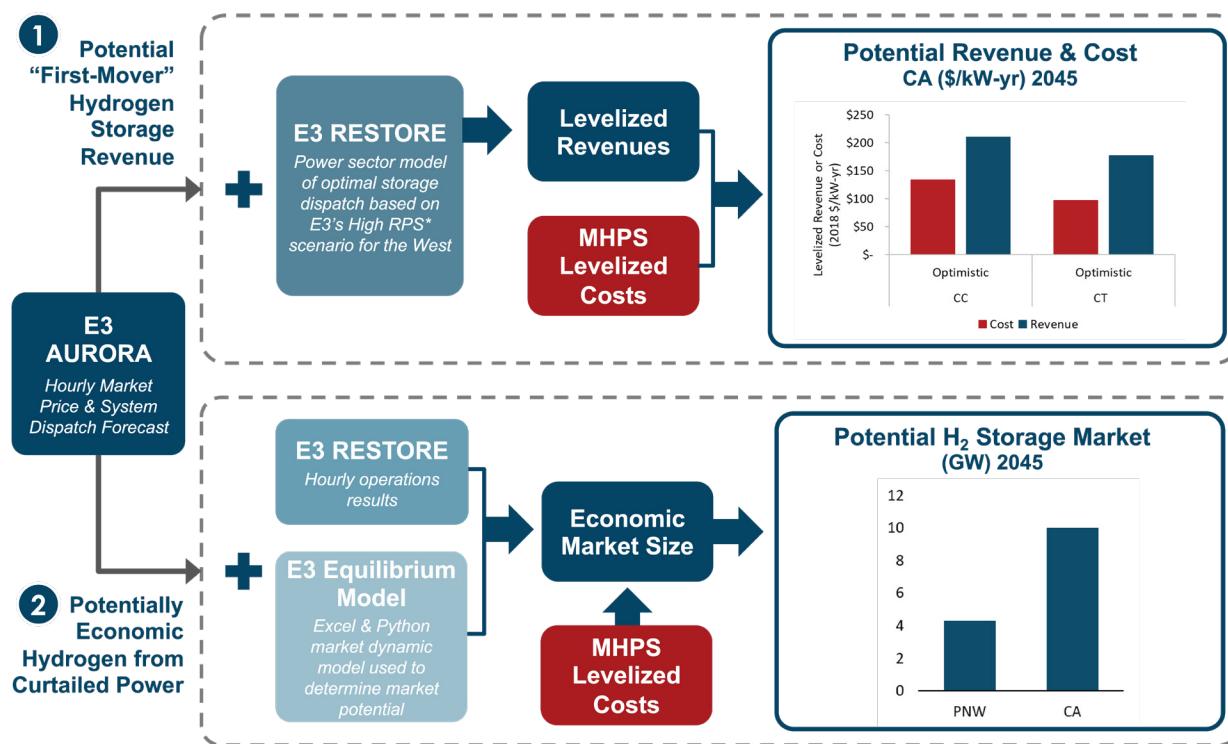
E3 used the energy market price forecast for two analyses. First, E3 utilized RESTORE, E3's proprietary energy storage model, to estimate the potential revenues associated with the 1000 MW hydrogen project. RESTORE maximizes revenues available from dispatch, subject to the system operating parameters, with market prices as an input and the storage resource treated as a "price taker", i.e., prices are assumed to be fixed across the entire range of storage operations. Because RESTORE allows storage to charge and discharge as is economic, charging can occur during low-price hours when it can be done profitably. The results shown in Figure ES-2 demonstrate that in the long-term (2045), a 1000 MW hydrogen storage project would be expected to have significantly positive net revenues under both conservative and optimistic electrolyzer capital cost assumptions.

Using the results from RESTORE, E3 then estimated the amount of economically viable long-duration hydrogen storage that could be produced from curtailed electricity, focusing on two regions, California and the Pacific Northwest, where E3's modeling suggests significant renewable curtailment in the 2030s and beyond. E3 first used the RESTORE model outputs to determine average arbitrage revenue from buying curtailed electricity to generate hydrogen and selling electricity back to the grid generated in a hydrogen-fueled combined cycle or combustion turbine power plant. E3 then built a custom model to determine the total viable long-duration hydrogen storage market size that resulted in breakeven fixed system cost and annualized system net revenue in the energy and capacity markets. In this analysis, E3 assumed that only curtailed electricity is available for charging the storage system, generating a conservative estimate of the total economic long-duration storage.

Based on these assumptions, the total amount of economically viable long-duration storage in California and the Pacific Northwest in 2045 is estimated at approximately 14 GW, as shown in Figure ES-2. Depending on realized cost reductions, it is possible that the market will support more economically viable long-duration energy storage capacity. However, other competing zero-carbon technologies that can provide firm power (e.g. advanced nuclear) may reduce the total viable market for long-duration energy storage using hydrogen but were not considered due to the project scope.

For the analysis, E3 utilized a combination of available public information on technology costs, in particular costs and trajectories developed by the Advanced Power and Energy Program at the University of California at Irvine (UCI) as part of E3's study for the California Energy Commission, "Natural Gas Distribution in California's Low-Carbon Future", as well as certain cost and performance assumptions provided by MHPS. The assumptions have been labeled based on the source throughout the report.

Figure ES-2: Approach to analyzing the potential role of hydrogen in the power sector and 2045 results.



* "Natural Gas Distribution in California's Low-Carbon Future", CEC-500-2019-055-D, 2019.

<https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/index.html>

The key findings from this study include:

- + **The most promising and realistic opportunity for carbon-neutral hydrogen is as long-duration energy storage for the electricity sector in a deeply decarbonized West.** Hydrogen could provide valuable firm generation capacity and long-duration energy storage, in a deeply decarbonized, high renewable future. The relatively low cost of hydrogen storage in geologic formations allows large amounts of energy to be stored in the form of hydrogen and used for seasonal shifting of energy. This is particularly useful for providing firm zero-carbon electricity during multiday periods with low wind and solar power generation. Curtailed energy from renewables and the falling costs of dedicated off-grid renewable power may provide cost-effective energy resources. Finally, the ability to combust hydrogen in existing thermal power plants and to transport it (with some equipment retrofits) in existing natural gas pipelines may be useful in reducing typical system costs. Given the limited project scope, E3 did not compare the economics of long-duration hydrogen energy storage to other sources of zero-carbon firm power that may compete with hydrogen.
- + **Carbon-neutral hydrogen could play a role in decarbonizing other sectors of the economy, particularly heavy-duty ground transportation.** Due to the low load carrying capacity, significant charging times, and necessary charging infrastructure required for heavy duty battery electric vehicles (BEVs), hydrogen fuel cell vehicles (HFCVs) are an attractive candidate to replace diesel heavy-duty vehicles (HDVs) to enable carbon-free trucking. HFCV's are cost competitive with BEVs for heavy-duty trucking on an operating cost (per ton-mile) basis, given that hydrogen vehicles have about twice the carrying capacity, and may continue to improve that cost competitiveness with reductions in station costs. Still, HFCV's remain more expensive than diesel trucking, and thus growth of HFCVs will be most likely if specific strict bans or limits are placed on the sale or operation of diesel HDVs.
- + **Carbon-neutral hydrogen's role is uncertain in buildings and industry, with potential opportunities foreseeable if the Western U.S. achieves carbon targets close to complete decarbonization.** Hydrogen has advantages over other zero-carbon alternatives for building and industrial end uses, including its ability to be used, stored and distributed through similar means as natural gas. However, there are significant and uncertain costs associated with upgrading existing natural gas distribution pipelines to accommodate hydrogen blends much above 7% by energy (20% by volume). Furthermore, the use of hydrogen as a fuel in buildings may not be cost-competitive with electrification alternatives, particularly in Southern parts of the Western U.S. In industry, there are some applications in which carbon-neutral hydrogen is likely to be competitive with electrification alternatives (e.g.

high process heat), however, both carbon-neutral hydrogen and electrification in industry remain relatively expensive, and there are currently limited policies in place today to push these industrial decarbonization strategies forward. Without stringent decarbonization targets it will be difficult for hydrogen to compete as a replacement to cheap natural gas, and competing with electrification options in buildings faces major cost and implementation challenges.

- **The most economic means of producing carbon-neutral hydrogen in the long run remains uncertain.** Until at least 2025, steam methane reforming (SMR) with 90% carbon capture and storage (CCS) is likely to be lower cost than electrolysis with renewable power, though project costs may be highly site-specific. However, by the mid-2030s, electrolysis with renewable power may become more economic, due to potentially rapid declines in electrolyzer costs, coupled with the availability of inexpensive renewables.
- **When underground storage is available, centralized hydrogen production from renewables in locations with on-site storage is lower cost than decentralized hydrogen production from renewables. Thus, locations with underground storage may serve as cost-effective energy “hubs”, providing hydrogen to locations without energy storage.** If hydrogen is generated using zero-carbon electricity, using centralized geologic hydrogen storage coupled with a network of hydrogen pipelines to deliver to multiple end users is more cost-effective than building a decentralized system with hydrogen storage at each end user's site, with no hydrogen pipeline network.

Uncertainties and Study Limitations

The future is uncertain and therefore the economic viability of hydrogen may change due to unforeseen events, new technology adoption or inventions, new market structures, unforeseen regulatory actions, and changes in both state and federal government policy. Thus, E3 makes no guarantee related to the results of this analysis and should not be held liable for any economic damages associated with independent investment decisions.

In particular, the power sector modeling performed in this study represents a preliminary assessment of the potential for long-duration storage in the West. E3's modeling to date has found that achieving a deeply decarbonized grid (i.e., more than 90% carbon-free) will require firm dispatchable generation or long-duration storage. However, due to project timing and scope, this project used existing modeling tools and research related to hydrogen and lithium-ion (Li-ion) batteries, and did not perform new portfolio optimization modeling of a broad suite of emerging zero-carbon resources and long-duration storage technologies.

We note that a robust evaluation of long-duration storage would require new and novel analytical tools, given the technical challenges of modeling a zero-carbon electricity system, particularly in serving load reliably across a broad range of weather and load conditions, and under multi-day low-renewable production events when long-duration storage is most valuable. As modeling capabilities improve, future work should use a market equilibrium capacity expansion model that is explicitly designed to value the role of long-duration energy storage, and to optimally choose from the suite of different technologies (e.g. long-duration hydrogen storage, new forms of chemical battery storage, advanced nuclear, compressed air energy storage, etc.) that could enable a reliable, low- or zero-carbon electricity grid. This approach would more thoroughly assess the market size, risks and opportunities for long-duration energy storage using hydrogen than has been possible in this preliminary assessment.

Differences Between this Study and E3's Study on the Challenge of Retail Natural Gas in California's Low Carbon Future

In April 2020, the California Energy Commission (CEC) published E3 and UCI's CEC-funded research study, titled "The Challenge of Retail Gas in California's Low-Carbon Future" (CEC-500-2019-055-F, the "retail gas" study).⁵ This study, consistent with previous E3 work, found that natural gas use decreases in all decarbonization scenarios that meet an 80 percent reduction of greenhouse gas emissions by 2050. Across different scenarios evaluated in the CEC retail gas study, there were steep reductions in natural gas use for electricity generation, and from implementing energy efficiency in industry and buildings. There was variation in natural gas use in buildings across scenarios based on the amount of building electrification.

In scenarios assuming no, or low levels of, building electrification and high levels of biomethane and hydrogen to decarbonize the gas pipeline, customer energy bills, and particularly the cost of home heating, was found to be significantly higher compared to electrified buildings. In California at least, with its relatively mild climate, E3 found that building electrification is likely to be a lower cost strategy to decarbonize buildings compared to the use of renewable natural gas. E3's research also suggested that

⁵ See: <https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf>

electrification will likely be the most cost effective decarbonization strategy for many applications in buildings and transportation (particularly light duty vehicles). At least in California, given the wide margin of cost-effectiveness between electrification and hydrogen fuel, we do not expect that this basic conclusion would change even with lower hydrogen cost assumptions.⁶ This study, performed for MHPG, focused instead on the economics of hydrogen as a form of long-duration energy storage in the electricity sector, and identifies more limited but feasible opportunities in other sectors.

Likewise, E3's analysis around options to decarbonize the transportation and industrial sectors remain similar to E3's prior work, even using slightly lower hydrogen cost assumptions in this study. Industry, heavy duty vehicles, and building heating needs in cold climates are expected to be difficult to fully decarbonize with energy efficiency and electrification alone. However, some level of electrification is likely in each. These sectors are more promising applications for the use of hydrogen or other zero-carbon fuels. There is still a great deal of uncertainty in how decarbonization policies and technologies will evolve over time. If dramatic cost declines for electrolyzers are realized, and as more curtailed electricity becomes available, hydrogen may realize more economic opportunities.

Importantly, the retail gas study did not evaluate the role of long-duration energy storage in the electricity sector, as is contemplated in this study. This study highlights a potentially important opportunity for hydrogen as long-duration energy storage medium across the West. Long-duration energy storage is likely to be particularly valuable as the electricity sector moves towards carbon neutral carbon targets. In addition, the role of electrolytic fuels like hydrogen are likely to be more limited if climate targets are set to an 80 percent reduction in greenhouse gases, but are likely to play a larger role if the region moves towards a carbon-neutral future.

⁶ See Appendix Figure 9-8 for a comparison of the hydrogen cost assumption's in the CEC retail gas study and this study.

Introduction

1.1 Overview and Project Questions

The push for economy-wide decarbonization has fueled serious interest in the potential for hydrogen as a zero-carbon resource. With characteristics similar to natural gas, hydrogen may be used in a wide range of applications, many of which are hard to decarbonize via other methods. Moreover, hydrogen may be able to take advantage of existing infrastructure, such as thermal power plants and natural gas pipelines to some extent, though higher blending percentages will trigger the need for upgrades and equipment modifications. Perhaps most importantly, if the West is to achieve ambitious clean energy targets, then significant energy storage or dispatchable zero-carbon resources will be critical to enabling that transition, and hydrogen is well-positioned to provide long-duration storage.

To better understand the potential for zero-carbon hydrogen, MHPS enlisted E3 to evaluate several key questions related to the future of hydrogen, with a focus on the Western U.S., including:

- + What are the most viable hydrogen production methods, based on expected future cost trajectories?
- + What is the market outlook for hydrogen across sectors in the Western United States under a deep decarbonization future?
- + What is the potential role of hydrogen as a long-duration storage medium in a deeply decarbonized Western electricity system?
- + What does the hydrogen supply chain in the West look like today, and how may this supply chain evolve in a deep decarbonization future?

The study scope relies on E3's existing work throughout the West. In particular, E3's work modeling economy-wide and electricity sector decarbonization has generated common findings that inform our perspective on the outlook for hydrogen, including:⁷

- + The development of **zero-carbon fuels**—for instance, biofuels, synthetic gas, and/or hydrogen—will be necessary to supply energy to end uses that are not easily electrified.
- + Achieving **absolute zero electricity sector emissions** is prohibitively expensive unless there is access to **zero-carbon fuels or long duration storage**, with potential emerging resources including hydrogen, advanced nuclear, synthetic fuels or biofuels.

1.2 Policy Landscape

Policy makers in the West are increasingly considering aggressive long-term economy-wide decarbonization targets. These targets, which range from non-binding goals to “on-the-books” laws, aim to dramatically lower the amount of greenhouse gases emitted across broad sectors of the economy by mid-century. Achieving deep decarbonization will transform the way we utilize energy in transportation, heating and electricity generation, sectors currently fueled by fossil fuels. A summary of key economy-wide and electricity sector policies by state is shown below in Figure 1-1. In particular, five states (California, Nevada, Washington, Colorado, New Mexico) all have stated goals or policies toward 100% clean energy.⁸ For example:

- + **California:** As the largest economy in the West, California has pursued a series of ambitious decarbonization goals and clean energy targets. Most notably, Executive Order B-55-18, issued by Governor Jerry Brown, articulates a goal of economy-wide carbon neutrality no later than 2045. While this EO does not carry the same weight as signed law, this ambitious goal would represent a future in which very little carbon is permitted in the West. California’s economy-wide target is complemented with an aggressive electricity sector law, SB 100, which requires eligible renewable energy resources and zero-carbon resources to supply 100% of retail electricity sales to California end-use customers by 2045.

⁷ These studies include:

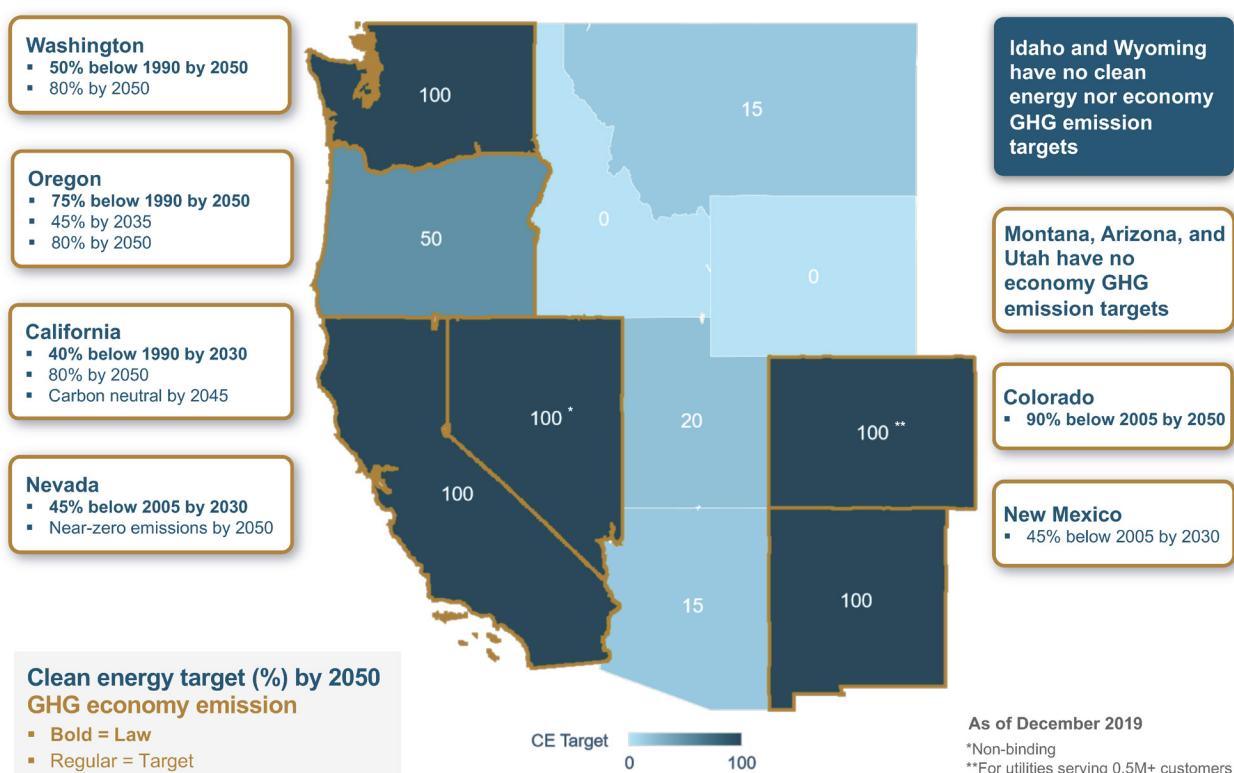
https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf
https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf
https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf

⁸ In 2019 the Governor of Montana also issued an EO that creates a council to take a “hard look at the challenges and opportunities” for achieving net-zero GHG emissions. https://governor.mt.gov/Portals/16/docs/2019EOs/EO-08-2019_Creating%20Climate%20Solutions%20Council.pdf?ver=2019-07-02-141610-417

- + **Washington:** In 2019, Washington state adopted the Clean Energy Transformation Act, which sets the state on a path to serve 100 percent of retail electric loads with carbon-free electricity.
- + **Colorado:** In 2019, Colorado enacted legislation that requires utilities serving 500,000 or more customers to supply 100 percent of retail sales with clean energy sources by 2050, as long as meeting the requirement is technically and economically feasible and in the public interest.

E3's work across the West has found that achieving targets of 80% economy decarbonization by 2050 will require the electricity sector to transition to almost entirely zero-carbon generation, and to do so while meeting increasing demand from electrification in other sectors. While there is significant uncertainty regarding implementation of the most ambitious goals, most states in the West have pledged to pursue a very low carbon future.

Figure 1-1: Executive orders and laws related to decarbonization goals and mandates in the West.



1.3 Scenario Design Philosophy and Modeling Approach

With this policy backdrop, E3 focused this study on evaluating the effect of a low carbon, high renewable future on the demand for hydrogen across the economy. E3's modeling to date suggests that decarbonization of at least 80% by 2050, consistent with some states in the West today, will be essential to support the use of renewable hydrogen across industries, as reflected in Figure 1-2. More importantly, to achieve decarbonization levels approaching net-zero or carbon neutral, zero-carbon resources such as hydrogen will be essential, particularly for removing the last few percent of carbon emissions on a path towards 100% decarbonization.

E3 assessed the potential demand for hydrogen using two well-known E3 models, PATHWAYS and RESTORE, which have been used extensively by state agencies, utilities and other stakeholders to evaluate low carbon futures in the West. These models differ significantly in their structure and assumptions, and thus E3's analysis of hydrogen's potential in buildings, industry and transportation is not perfectly comparable with its analysis of the power sector opportunities. While PATHWAYS enables E3 to perform a broad economy-wide assessment of hydrogen's potential, E3's RESTORE allows for more detailed evaluation of the electric power sector.

1.4 Western U.S. PATHWAYS Model

This study used E3's PATHWAYS model to assess the potential opportunities for hydrogen in a deeply decarbonized West. PATHWAYS is an economy-wide energy and greenhouse gas scenario planning model developed by E3 to create decarbonization policy scenarios across multiple economic sectors. It is a long-horizon, infrastructure-based stock rollover model, with detailed representation of the buildings, industry, transportation, and electricity sectors. E3 developed the PATHWAYS framework in 2008 to help policymakers, businesses and other stakeholders understand and compare plausible decarbonization scenarios. The model has since been modified and improved over time in projects that analyze deep decarbonization in jurisdictions across North America.

In the model, each type of infrastructure consumes energy and produces emissions differently, but they collectively determine the region's emissions trajectory. Many of these technologies are long-lived. For instance, a home built today will likely still be in use by mid-century. Because investments made in the near-term shape the energy system of the future, the PATHWAYS model includes a detailed, "bottom-up" stock accounting of the

region's energy infrastructure on a technology-specific level. With detailed accounting of residential, commercial, industrial, and transportation equipment lifetimes, PATHWAYS determines the pace of change necessary to deploy decarbonization strategies while avoiding costly early retirement and captures potential path dependencies of near-term decisions. Energy demand is driven by forecasts of population, building square footage, vehicle miles traveled, and other drivers of energy services. The rate and type of technology adoption and energy supply resources are all user-defined scenario inputs.

For this study, E3 built a PATHWAYS model that represented the Western U.S. using data from two Census regions (Pacific and Mountain).⁹ E3 then developed three scenarios that represent the potential role of hydrogen in a deeply decarbonized future, including:

- + **Mid-Hydrogen Scenario** represents a world in which hydrogen plays a moderate role in transportation sector, and a minor role in the industrial sector. This scenario is built to be consistent with a world in which the West achieves economy-wide 80% reductions relative to 1990 by 2050. In this scenario, the primary decarbonization strategy in passenger transportation remains electrification. Electrification is used as the dominant mode in short duty freight and industry as well, but hydrogen provides a role in decarbonizing long distance, heavy duty freight where electrification might not be a feasible option, and is used to decarbonize some industrial processes, especially those around high temperature needs in which electrification might not be cost effective. In this scenario, electrification is still the dominant form of decarbonization for decarbonizing residential and commercial buildings.
- + **High-Hydrogen Scenario** represents a world in which hydrogen realizes much of its technical potential in all sectors with moderate requirements for supporting policy and infrastructure upgrades. This scenario is built to be consistent with a world in which the West achieves economy-wide 80% reductions relative to 1990 by 2050. Hydrogen continues to be a key decarbonization strategy in heavy duty, long distance freight applications, but hydrogen also provides a smaller role in short distance freight and in passenger vehicles. This is consistent with a worldview where certain trips, such as long-distance trips, are not amenable to electrification and there is limited ability to use advanced biofuels as a drop-in fuel replacement so hydrogen vehicles provide a decarbonization strategy for these end uses. Similarly, this scenario

⁹ We note that the Pacific region data includes Alaska and Hawaii, which are technically outside the scope of this study but make up a small portion of the overall energy demand.

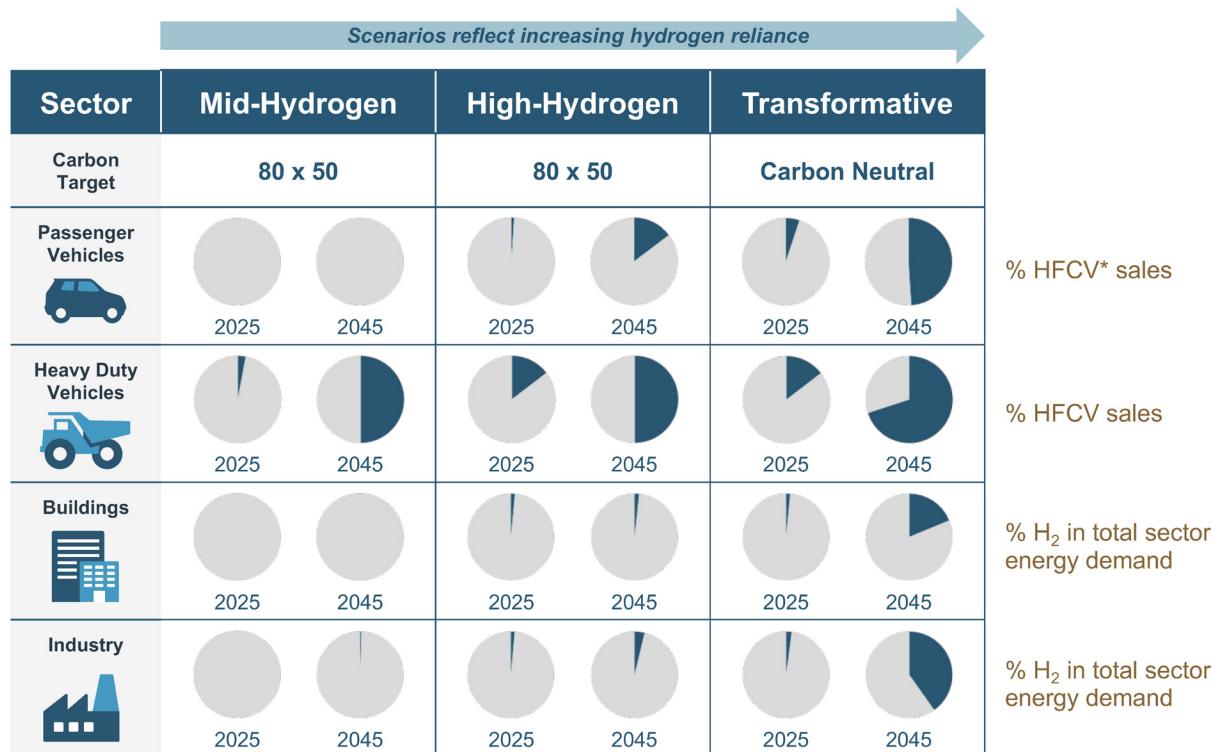
assumes further hydrogen use in industry and buildings, specifically with a pipeline blend of 7 percent hydrogen in the pipeline distribution infrastructure. This blend is consistent with technical limits to hydrogen blending within natural gas pipelines without causing significant pipeline infrastructure upgrades or triggering changes to end use devices. Electrification continues to be the dominant decarbonization strategy in buildings.

- ✚ **Transformative Scenario**¹⁰ represents a world in which hydrogen has a substantial presence in transportation, buildings, and industry, assuming commensurate policy drivers and enabling infrastructure. This scenario is consistent with a world in which the West achieves decarbonization consistent with a “net zero” carbon outcome. This scenario assumes major upgrades in natural gas pipelines across the West to accommodate 100 percent hydrogen blend in the distribution pipeline. As in the High-Hydrogen scenario, building electrification is the dominant decarbonization strategy in buildings, but fuel combustion is used to provide space heating in cold climates, where electrification alone could potentially cause large electric generation capacity infrastructure builds. Unlike the High-Hydrogen scenario, pure hydrogen as part of the hydrogen pipeline infrastructure is used as the fuel of choice for providing space heat in buildings in the cold climates, as opposed to the natural gas with hydrogen blend in the High-Hydrogen scenario. Furthermore, hydrogen is used as the dominant decarbonization strategy in industry, with all pipeline gas usage being replaced with hydrogen, and with significant fuel switching of existing liquid and solid fuels to hydrogen as well. In heavy duty freight, hydrogen is the dominant decarbonization strategy, and in passenger vehicles hydrogen vehicles and electric vehicles are both used to decarbonize passenger transport.

The scenarios rely on faster and more extensive reliance on hydrogen, based on assessing the range of assumptions regarding its relative costs and feasibility compared to alternative decarbonization strategies. A summary of the assumptions made regarding the penetration of hydrogen in each scenario is shown in Figure 1-3 below, with detailed sector-by-sector discussions in the relevant section.

¹⁰ We note that the transformative scenario does not assume that a global, or continental U.S., hydrogen supply chain exists. This scenario is “transformative” by enabling hydrogen to be available broadly in the West (i.e., not limited by pipeline blending). However, for this study, we do not assume that hydrogen produced in locations with extremely good renewable electricity production capabilities, such as the Atacama Desert, is imported into the U.S., nor does it assume that the desert Southwestern U.S. becomes a production hub for hydrogen to be used outside the West.

Figure 1-2: PATHWAYS scenario modeling assumptions.



* HFCV refers to hydrogen fuel cell vehicle.

1.5 Power Sector Modeling Approach

To evaluate the outlook for hydrogen in the power sector, E3 performed two analyses based on our existing modeling of the sector. First, E3 estimated the potential market revenues of a 1000 MW hydrogen storage project using E3's RESTORE. RESTORE uses existing price forecasts and is built to allow the storage to charge and discharge based on market electricity prices. E3 performed the RESTORE analysis for the Southern California (SP-15) market. We note that the model assumes the 1000 MW hydrogen-storage project is a price-taker, using the price forecast from E3's Aurora High RPS scenario. This price-taker assumption is generally valid as long as the added storage capacity is relatively small and thus does not change existing market dynamics. Further additions of storage capacity could decrease the average revenues of the entire fleet (as shown by the market equilibrium model described later in this section), and thus the RESTORE results should be considered as revenue for projects not expected to significantly change overall market prices.

Following this preliminary analysis, to assess the potential amount of economically viable long-duration hydrogen storage in a deeply decarbonized West, E3 developed a model in Python and Excel that estimates the total market size for long duration hydrogen energy storage in California and the Pacific Northwest. The model assessed typical average energy arbitrage earnings from RESTORE using E3's High RPS scenario in Aurora. The model assumes that curtailed power is used for generating hydrogen via electrolysis, subject to the hourly availability of curtailed electricity and electrolyzer power capacity. By adding storage capacity incrementally and updating the hourly electricity price and curtailment profiles, E3 calculated the net energy revenues from storage discharge. The energy revenues, as well as earnings from providing capacity, are compared to the levelized fixed costs of the hydrogen storage system to determine the economically viable market size for each technology combination and region studied. For this project, E3 focused on California and the Pacific Northwest, given that most observed curtailment in our modeling occurs in these regions. E3 applied the market equilibrium model to two types of generation technologies, combined cycle gas turbines (CCGTs) and combustion turbines (CTs), under various electrolyzer cost scenarios. Two vintage years, 2035 and 2045, were modeled with technology cost and performance assumptions consistent with the vintage year modeled.

2 The Costs of Hydrogen Production

2.1 Hydrogen Production Methods

Hydrogen can be produced by extraction from water or extraction from fossil fuels, with the production method determining both carbon emissions and its cost. Today, the predominant method of producing hydrogen in the United States is via steam methane reforming (SMR), which relies on a methane source (commonly natural gas), steam and heat to produce hydrogen and carbon dioxide. While this method, deemed “brown” hydrogen production, is the cheapest and most widespread method today, it emits significant amounts of carbon dioxide, and thus is not a viable method for decarbonization.

In contrast, we evaluated low-carbon methods of hydrogen production, including:

- + **SMR with carbon capture and storage (CCS), or “blue” hydrogen:** This method involves coupling SMR with CCS, which allows for the reduction of atmospheric carbon emissions.
- + **Electrolysis using renewable electricity, or “green” hydrogen:** This method involves splitting water into hydrogen and oxygen via electrolysis¹¹ with renewable electricity. This renewable electricity could be generated on-site (e.g., with a dedicated wind or solar plant) or sourced from the grid to make use of otherwise-curtailed renewable electricity.
- + **Electrolysis using nuclear energy, “pink” hydrogen:** This method involves splitting water into hydrogen and oxygen using electricity, and in some cases heat, from nuclear energy. Generation IV nuclear plants, which are currently in the research and development phase, operate at very high temperatures. This would enable the use of heat to increase the overall electrical efficiency of pink hydrogen production.

¹¹ As discussed in Section 7.1.1, alkaline electrolyzers are the most commercially available technology today although PEM and SOEC electrolyzers may become competitive with future cost declines.

This study primarily focuses on electrolysis using alkaline electrolyzers given their current maturity relative to other technologies like proton electrolyte membrane (PEM) and solid oxide. For hydrogen to enable a low-carbon future, significant declines in the cost of zero-emissions hydrogen production must be realized.

2.2 Hydrogen Production Costs

The costs of hydrogen production will have a tremendous impact on the viability of renewable hydrogen as a zero-carbon resource. As described above, E3's study focused on production of hydrogen via SMR, SMR with CCS, and electrolysis. The costs of producing hydrogen through SMR are well established. The process is widely used for production of hydrogen used in ammonia and methanol production as well as petroleum desulfurization. In contrast, the cost of electrolysis is much higher today. If projected levels of deployment and learning are realized, electrolysis could outperform SMR after 2035, but substantial uncertainty exists. The future viability of renewable hydrogen produced via electrolysis will depend on the realized trajectory of capital cost declines over the next 30 years and the availability of inexpensive renewable power.

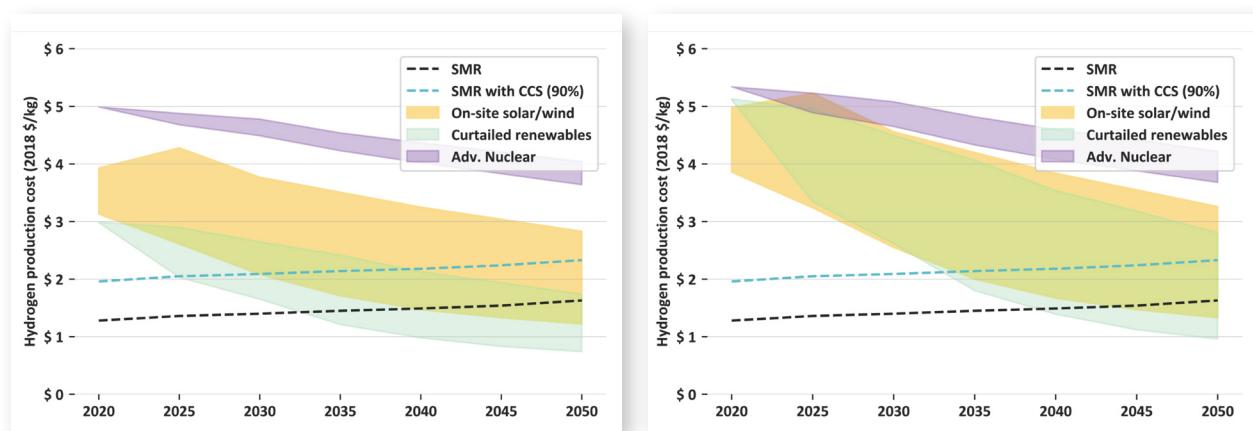
E3 completed two future cost comparisons across the hydrogen production methods outlined above. The first was based on MHPS alkaline electrolyzer capital cost assumptions. The second was derived from E3's existing alkaline electrolyzer capital cost assumptions, which are based on information developed by the University of California at Irvine.

The uncertainty in hydrogen production cost arises from the uncertainty in electrolyzer capital expenditures, efficiency and renewable power cost projections. Under the MHPS-informed optimistic cost projections, electrolyzer capital costs decrease from \$600/kW in 2020 to \$70/kW in 2050 with an underlying 25% learning rate assumption. Under E3/UCI optimistic cost projections, electrolyzer capital costs decrease from \$1,124/kW in 2020 to \$132/kW in 2050 with an underlying learning rate of 25% gradually decreasing to 10% by 2050. In both cases, we assume over 1300 GW of cumulative installed capacity by 2050, up from 7.6 GW in 2020. For some context, solar PV modules have experienced a learning rate of 22.5% from 1976 to 2016¹². However, the realization of these cost declines is strongly reliant on policy support and continued deployment at anticipated levels. Under the optimistic and conservative scenarios, the electrolyzer efficiency increases from 70% today, to 80% and 75% respectively in 2050. These electrolyzer capital costs, learning curves, and assumed capacity build assumptions for E3 and MHPS are shown in Figure 9-1 in the Appendix.

¹² Capital costs reflect the electrolyzer stack, the mechanical balance of plant, and the electrical balance of plant (uninstalled). Costs exclude additional project-specific costs required for permitting, design and contingency. These costs are significant but hard to quantify given costs are shared with generation assets (e.g., CT or CCGT). Therefore, these costs are not included in our assessment.

¹³ International Technology Roadmap for Photovoltaics (ITRPV) report, Sept 2017

Figure 2-1: Hydrogen costs by production method using (a) MHPS capital costs with E3 learning curves and (b) E3/UCI capital costs and learning curves.



The renewable power cost projections range from the “low” (cost) scenario to the “mid” scenario in the NREL Annual Technology Baseline (ATB), 2019¹⁴. The cost projections from curtailed renewables assume that the power is available free of cost and that an electrolyzer utilization rate of 15% can be attained. As will be discussed in Section 3.3, the projected curtailment varies significantly from one state to another. Additionally, a significant portion of the curtailment can be attributed to local transmission constraints and not system-wide overgeneration. Thus, not all of it may get absorbed. As shown in Figure 2-1, there is significant overlap between cost ranges associated with using dedicated on-site renewables and those of solely relying on curtailed power. Thus, further risk analysis is needed before opting for the latter based on seemingly favorable economics in the most optimistic scenario. Given the nascent nature of advanced nuclear technologies like small modular reactors and molten salt reactors, the NREL ATB only projects a single “mid” scenario cost which stays much higher than the renewable power-based costs despite the higher capacity factor achievable. Use of heat generated by the nuclear reactor is not considered in these cost projections.

¹⁴ <https://atb.nrel.gov/>

Over time, both electrolyzer capital costs and renewable power cost fall in real terms. However, the percentage contribution of electrolyzer capital costs to the total hydrogen production cost decreases with time, while that of the renewable power increases. For example, under UCI's electrolyzer capital assumptions and NREL's low solar cost projections, electrolyzer capital costs account for 52% of the total costs in 2020, reducing to 17% in 2050. On the other hand, solar power costs account for 33% of the total cost in 2020, increasing to 46% in 2050. The remainder is filled by non-fuel O&M costs which don't change significantly in real terms. As a result, using the more optimistic electrolyzer capital projections informed by MHPS does not lead to a significant total production cost decline in later years. The electrolyzer capital contribution to the entire Power-Gas-Storage-Gas system will be even lower once costs associated with storage and gas turbines, which won't decrease substantially with time, are considered.

Under both sets of electrolyzer capital cost assumptions, producing hydrogen via SMR without CCS is expected to be less expensive than other methods until 2030¹⁵. E3's electrolyzer cost assumptions find that SMR with 90 percent CCS is likely to be cheaper than electrolysis via renewables until early 2030s, while MHPS electrolyzer cost assumptions find it will be cheaper only until 2025. It is important to note that a stringent cap on carbon emissions or price on carbon that force a 100% CCS may hurt the economics of SMR with CCS, as the process may require purchasing biogas to blend into the natural gas fed to the SMR or additional direct air capture of carbon dioxide to sequester the remaining carbon emissions.

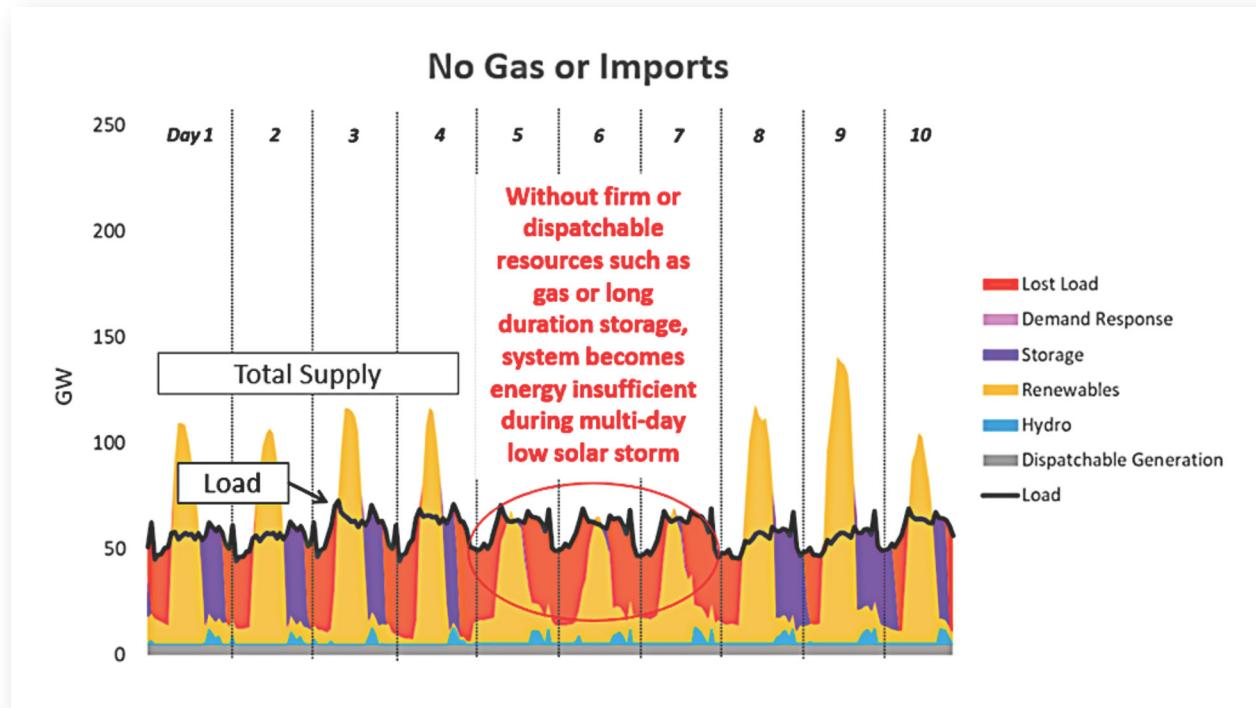
¹⁵ While hydrogen production costs using CCS are estimated to be cheaper on average than using electrolysis, costs will vary from site to site, particularly based on the sequestration and storage options. Carbon sequestration may be more expensive than electrolysis at certain locations if sequestration costs are high. However, the limited deployment of CCS and carbon pipelines to date makes a definitive assessment difficult at the particular site of the ACES project.

3.1 The Challenge with Meeting Deep Decarbonization Targets

Achieving the aggressive decarbonization targets described in Section 1 will require near complete decarbonization of the electricity sector, particularly in states that have already adopted 100% clean energy policies or goals (i.e., California, Nevada, Washington, Colorado, New Mexico). This decarbonization must occur while serving increasing load from electrification of other sectors. Modeling performed by E3 in California and the Pacific Northwest, for example, finds that decarbonization of around 90% can be achieved with solar PV, onshore and offshore wind, and existing energy storage technologies such as batteries and pumped hydro—as long as the remaining power comes from firm dispatchable generation, e.g., natural gas. This firm resource is required because solar and wind are intermittent resources and cannot easily dispatch electricity on demand. While lithium-ion (Li-ion) batteries are valuable for diurnal balancing, or shifting energy within each day, a resource like firm gas is required to maintain system reliability and prevent loss-of-load during prolonged periods of low solar and wind output, particularly when low production events coincide with high load events. This pattern is shown in Figure 3-1 below.

Removing the remaining firm fossil capacity from the system will require drawing from an emerging potential carbon-free resource or energy storage technology. This includes hydrogen, natural gas with carbon capture and storage, biofuels, or nuclear. In particular, hydrogen could serve as long-duration energy storage by: 1) utilizing renewable energy that would otherwise be curtailed or dedicated off-grid renewables to produce hydrogen; 2) storing it underground until periods of low output; and 3) combusting it in gas turbines to provide zero-carbon energy on demand.

Figure 3-1: Using only today's diurnal energy storage technologies, electric reliability cannot be maintained without some dispatchable gas generation or long duration storage to serve loads during periods of low-renewable generation.



3.2 Modeling a High Renewables Future in the West

The Western U.S. represents most of the Western Electricity Coordinating Council (WECC), with remaining small portions in Mexico and Canada.¹⁶ Today, capacity in the WECC is dominated by natural gas in California, coal in Arizona, Alberta, Montana, and Utah, and hydro in the Pacific Northwest. However, given RPS targets and restrictions on gas builds, large quantities of renewable resources have been added to the regional resource mix over the last several years. Despite these additions, in the near term, the region is expected to be capacity tight as once-through cooling plants retire in California and economic coal retirements occur throughout the West. These two trends suggest that while the region is expected to experience significant near-term renewable growth, it is still expected to be short on dispatchable generation required for reliability.

¹⁶ All of the WECC BAs are vertically integrated or municipal utilities with the exception of the California ISO (CAISO). The CAISO operates a wholesale regional market, representing around 80% of California's load. The Interconnect has a voluntary regional, five-minute ahead Energy Imbalance Market (EIM), managed by CAISO in order to integrate more renewable generation.

For this study, we relied on E3's High RPS market forecast for the WECC over the next 30 years to assess the potential for economic hydrogen production and to evaluate potential revenues for a 1000 MW hydrogen long-duration storage project. In particular, the E3 High RPS scenario assumes attainment of the various renewable or clean energy targets that are being legislated in the West, including the attainment of various 100% renewables or clean energy targets (current as of June 2019). This scenario's modeled resource portfolio and generation mix are shown below in Figure 3-2 and Figure 3-3. The modeling is based on technologies that are commercially available today. Thus, builds in this scenario are dominated by steady increases of solar and battery storage. More information regarding this forecast is available in the Appendix.

We note that although this forecast represents a high renewables future, it is not a 100% clean energy future, even though the latter would reflect a future world most favorable to hydrogen. A near- or at-zero carbon modeling scenario was not available given the timing constraints of this study, and the inherent limitations of Aurora in modeling deeply decarbonized electricity system operations. E3 anticipates that to achieve an even more carbon-constrained future, significantly more renewable overbuild would be required, resulting in even more renewable curtailment. In this world, even more long-duration storage can be expected to be economically viable, given that the need for dispatchable generation will increase to compensate for the retired gas on the system.

Figure 3-2: WECC-wide resource portfolio in E3's Aurora High RPS scenario.

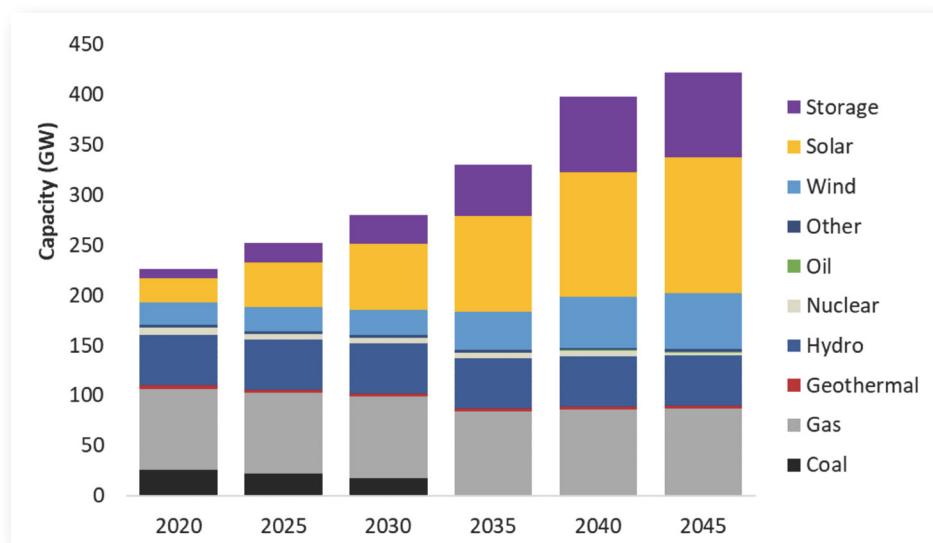
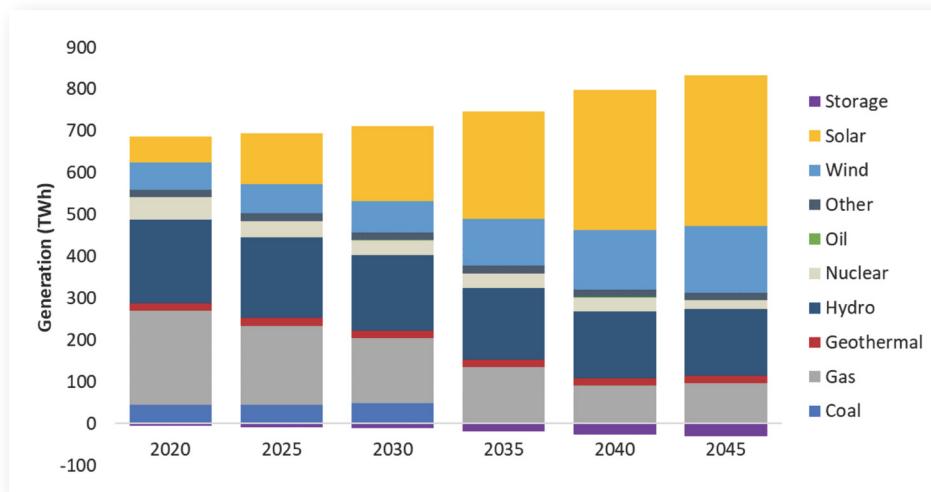


Figure 3-3: WECC-wide generation in E3's Aurora High RPS scenario.¹⁷



3.3 Renewable Curtailment

Curtailed renewables could provide free renewable energy to power electrolysis, and thus an opportunity to lower hydrogen production costs relative to other means (as shown in Figure 2-1). As renewable penetration grows, system curtailment will ramp up significantly. The penetration of renewables creates two types of curtailment:

- + **Local and transmission constraints:** Occurs where there is local congestion as the renewable build outpaces new transmission infrastructure. This source of curtailment can be mitigated through storage placement in congested pockets.
- + **Systemwide overgeneration:** Occurs when there is either high renewable generation or inflexible thermal commitment that surpasses the needed load. This source of curtailment may be mitigated by storage, exports, and reduced commitments from thermal resources.

Existing CAISO estimates suggest that, in their system, approximately 40% of curtailment today is due to systemwide overgeneration. Curtailment as a result of system overgeneration is also more readily usable to fuel hydrogen production, given the lack of access constraints.

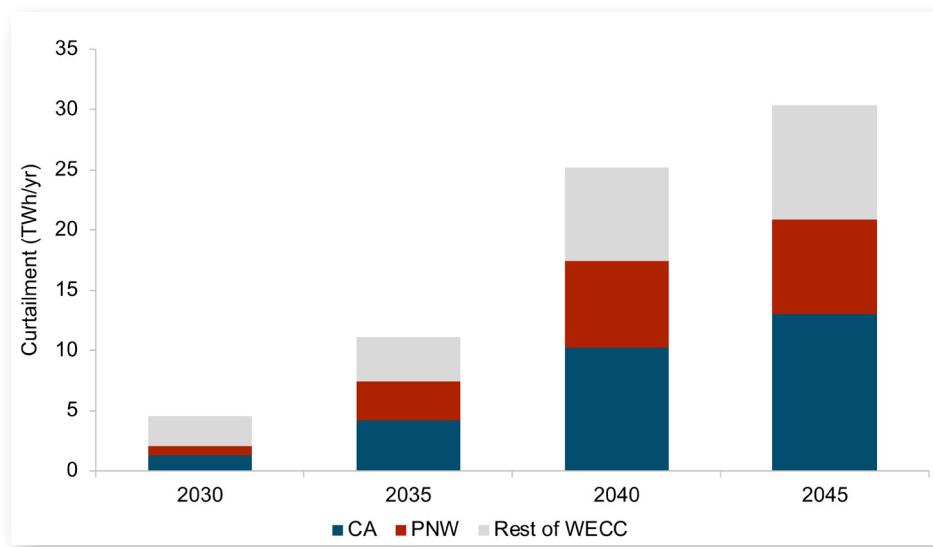
¹⁷ E3's Aurora High RPS forecast achieves about 88% zero-carbon generation by 2045. Generation from batteries is the net amount from charging and discharging.

¹⁷ CAISO Market Performance Reports.

E3's High RPS scenario in Aurora was used in this study to estimate the system curtailment over the next 30 years. The growing curtailment reflects the increasing renewable overbuild in order to meet increasingly stringent RPS targets. However, in the model, curtailment is dampened by the significant short-duration battery build in the system, which occurs given that the model predicts increasing negative pricing that enables economic battery storage builds to provide diurnal balancing. In addition, because some gas remains on the system, less curtailment occurs than one might expect in a more overbuilt system. Finally, because the Aurora market price forecast is performed zonally, the model does not predict as much curtailment as observed in reality, because it assumes no internal transmission constraints and thus is only capturing curtailment associated with system overgeneration.

E3's model estimates of total curtailment in the High RPS scenario are shown in Figure 3-4. This estimate may be conservative for the reasons discussed above. As the figure shows, the largest portions of WECC curtailment occur in California and the Pacific Northwest.

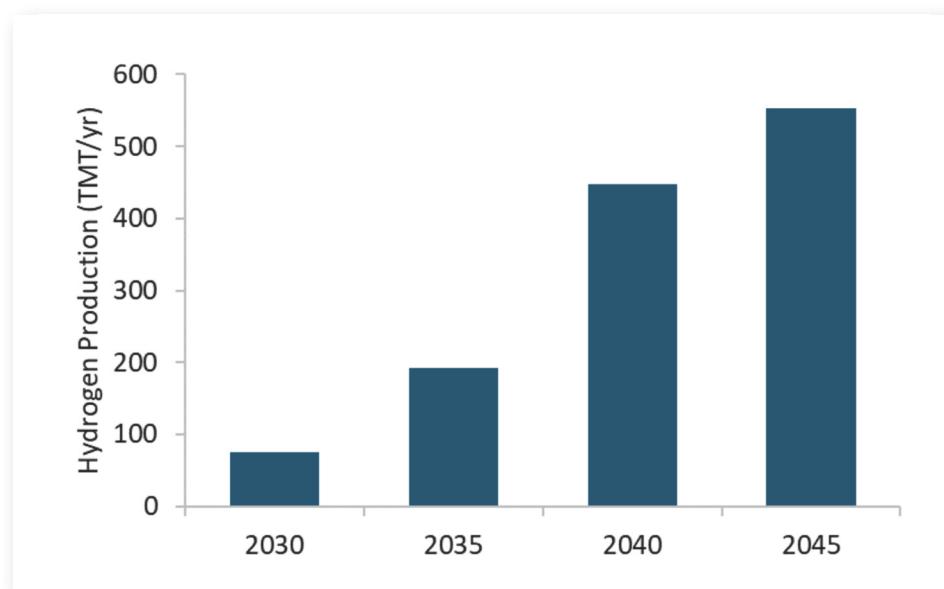
Figure 3-4: Total estimated WECC curtailment under E3's Aurora High RPS scenario.¹⁹



¹⁹ Rest of WECC includes Alberta, British Columbia, and North Baja California.

Based on this data, E3 estimated the total potential hydrogen production from curtailed renewables in the WECC as around 200 TMT/year by 2035 and 600 TMT/year by 2045 (Figure 3-5). As noted above, results are based on a future electricity market in which significant renewable curtailment is consumed by battery storage and some load continues to be met by thermal generators. This implies that total curtailed power could be larger, which would enable greater hydrogen production from curtailed power. Hydrogen may also be economically produced from off-grid renewables, as discussed above.

Figure 3-5: Potential total annual hydrogen production (thousand metric tons/year) from WECC curtailment under E3's Aurora High RPS scenario.²⁰



3.4 Levelized Costs of Storage in the WECC

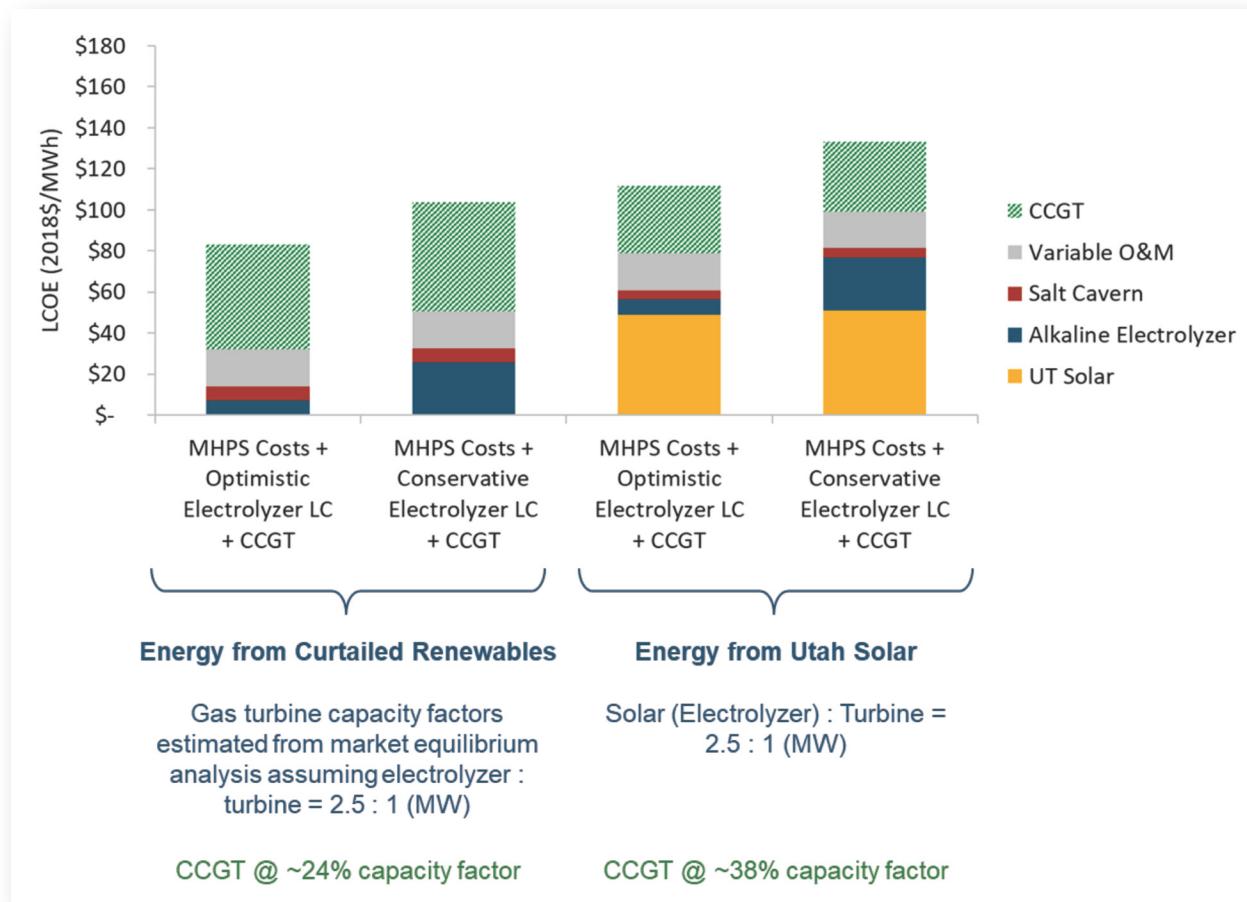
To evaluate the cost competitiveness of hydrogen long-duration storage, E3 evaluated the levelized cost of electricity (LCOE) for hydrogen storage and compared it to the LCOE of Li-ion battery storage, the most common source of commercial storage. Using electrolyzer cost assumptions provided by MHPG, E3 calculated the LCOE of hydrogen storage for a range of gas turbine capacity factors, assuming onsite solar energy in Utah and 1000-hour storage capacity with minimal losses from the salt cavern. We chose 2040, the latest data year in E3's Pro Forma model, as the analysis year for LCOE calculations.

²⁰ The analysis assumes that curtailment from all 16 zones modeled in the WECC (including Alberta, British Columbia, and North Baja California) is available for hydrogen production, alkaline electrolyzers operate at efficiencies consistent with the optimistic learning curves developed by UCI as part of E3's study for the California Energy Commission's "Natural Gas Distribution in California's Low-Carbon Future", and transmission losses of 8%.

Figure 3-6 shows the cost components of LCOE of hydrogen storage systems with CCGT and MHPS optimistic electrolyzer costs (LCOE breakdown for CT systems and E3 cost assumptions are shown in Figure 9-1 through Figure 9-4 in the Appendix). For this calculation, in the case of dedicated off-grid solar, solar capacity and CCGT or CT capacity are sized at a 2.5 :1 ratio based on MHPS inputs, and the electrolyzer size is set equal to solar capacity to maximize the capture of solar energy. This sizing implies an optimal capacity factor of about 38% for CCGT (and 29% for CT, see Appendix Section 9.1). In the case of curtailed renewables, the gas turbine capacity factor is estimated from economically viable curtailment in the analysis in Section 3.6 by assuming a system with electrolyzer-to-gas turbine capacity ratio of 2.5:1. The implied capacity factor is about 24% for CCGT (and 19% for CT, see Appendix Section 9.1). Both gas turbine capacity factors are in the range of what E3 believes a future firm resource such as hydrogen storage would have.

²¹ MHPS commercial experience suggests that electrolyzer O&M cost may be a fraction of the currently assumed \$10/MWh in E3's analysis (based on study by UCI: <https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/index.html>).

Figure 3-6: Breakdown of LCOE of hydrogen storage in 2040 for CCGT systems with MHPS capital cost assumptions and E3/UCI electrolyzer learning curves (LC) applied.



Notes: LCOE = leveled cost of electricity, CCGT = combined cycle gas turbine, LC = learning curve, UT = Utah, O&M = Operations and maintenance

²² We note that the range of hydrogen CCGT and CT costs are based on the upper bound (E3 initial capital cost with conservative learning curves) to lower bound (MHPS initial capital cost with optimistic learning curves). Battery costs are based on Lazard's Leveled Cost of Storage Analysis v4.0: <https://www.lazard.com/media/450774/lazards-leveled-cost-of-storage-version-40-vfinal.pdf>.

²³ The range of roundtrip efficiency of hydrogen storage systems was estimated for 2040 by assuming an electrolyzer efficiency (HHV) of 76% in the Optimistic case and 73% in the Conservative case, and a CCGT efficiency of 65% and CT efficiency of 50% based on MHPS inputs.

Figure 3-6 demonstrates that the capital and variable O&M costs of electrolyzers and capital cost of salt caverns all represent small portions of the overall LCOE of hydrogen storage systems. Electrolyzer capital and variable O&M costs would further decrease as the technology improves and project scale increases, although these costs remain uncertain given that there are few commercial projects to date.²¹ In contrast, solar and gas turbine (CCGT in Figure 3-6) costs dominate the LCOE and are both sensitive to gas turbine type and capacity factor. As shown on the left half of Figure 3-6, using curtailed renewable energy enables a much lower LCOE. Importantly, results in Figure 3-6 assume a new CCGT, which implies that potential reductions in LCOE may be achieved by retrofitting existing CCGTs at locations with access to low-cost storage or a hydrogen pipeline. Similar results are provided in the appendix for CTs.

In Figure 3-7, we demonstrate that hydrogen storage systems could compete with other storage technologies such as Li-ion batteries on an LCOE basis for long-duration storage applications. This could be seen in the LCOE comparison in Figure 3-7 for different standby durations. In Figure 3-7, hydrogen storage LCOEs range from MHPS optimistic to E3 conservative cases, and Li-ion battery storage LCOEs are based on Li-ion battery costs in Lazard's Levelized Cost of Storage Analysis v4.0, used in E3's Pro Forma model. Utah solar is assumed to be the fuel for both storage systems, with cost estimates sourced from E3's Pro Forma model. Solar and CCGT or CT are sized at a capacity ratio of 2.5 : 1 for hydrogen storage systems, same as in Figure 3-6. Solar and batteries are sized at a capacity (MW) ratio of 1 : 1 based on recent projects in California and Hawaii to maximize solar energy storage, and any excess solar energy is assumed to be sold to the grid at \$20/MWh.

²¹ MHPS commercial experience suggests that electrolyzer O&M cost may be a fraction of the currently assumed \$10/MWh in E3's analysis (based on study by UCI: <https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/index.html>).

Figure 3-7: Comparison of LCOE between hydrogen storage and Li-ion battery storage at increasing standby durations, assuming Utah solar as a fuel and 2040 costs.²²

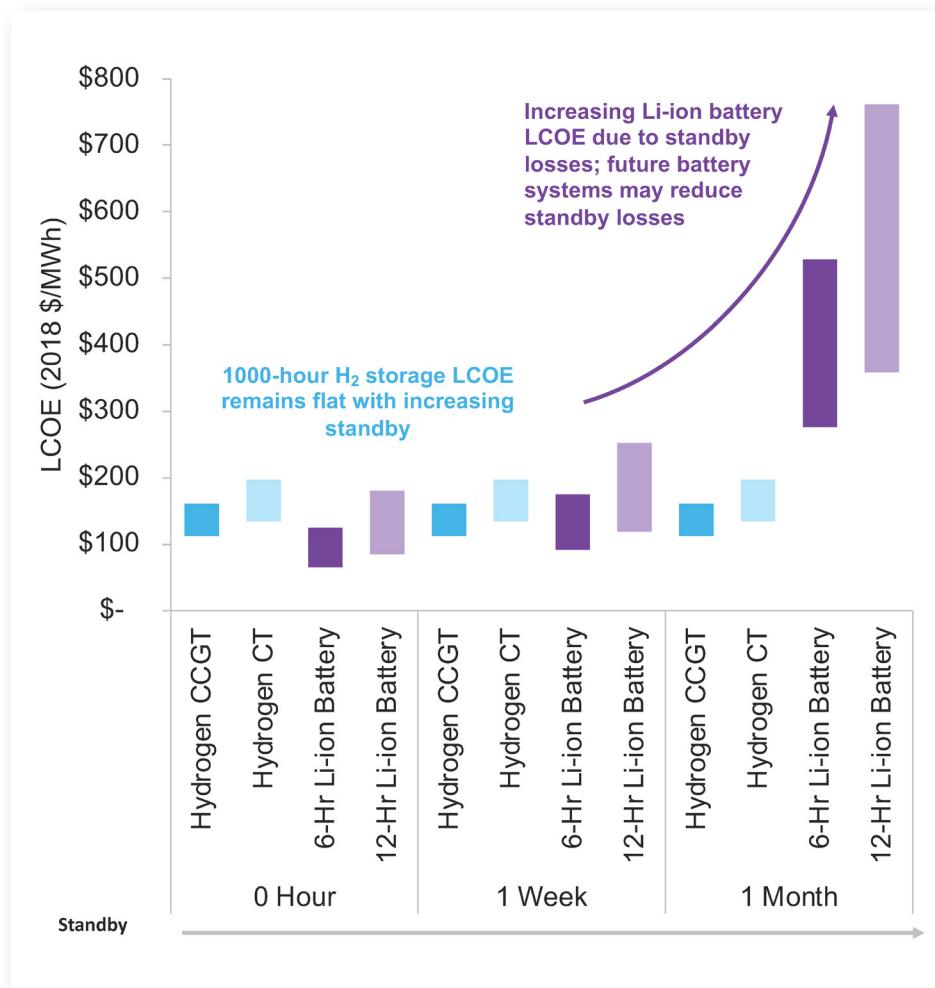


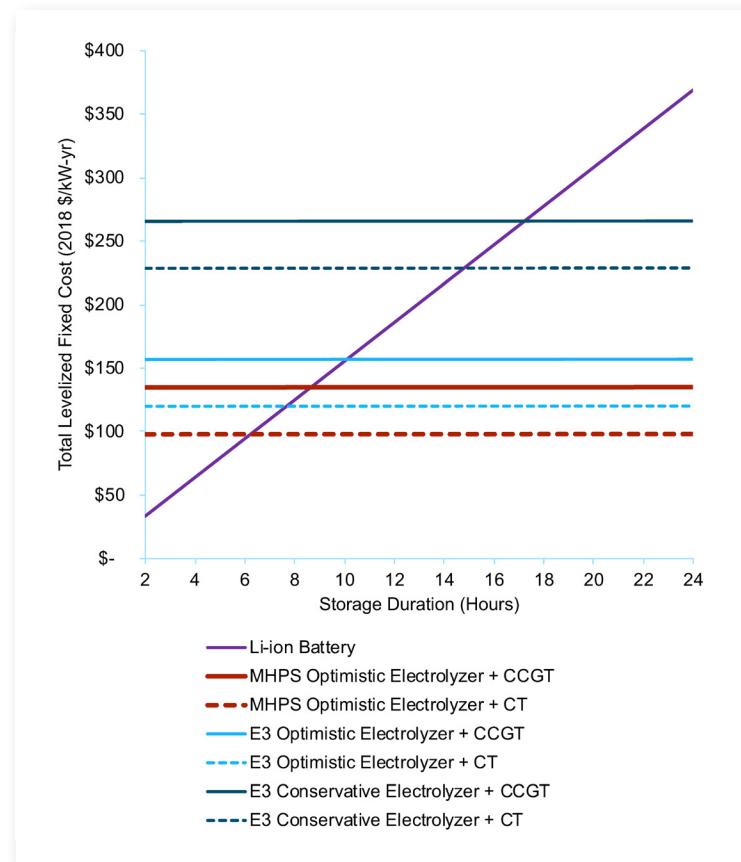
Figure 3-7 shows that Li-ion batteries have a cost advantage in shorter-duration applications due to their higher roundtrip efficiency at minimal standby losses (assumed to be 85% with a fixed standby loss of 0.2% of maximum Li-ion battery energy capacity/hour; compared to 37%–49% roundtrip efficiency assumed for hydrogen storage systems²³).

²² We note that the range of hydrogen CCGT and CT costs are based on the upper bound (E3 initial capital cost with conservative learning curves) to lower bound (MHPs initial capital cost with optimistic learning curves). Battery costs are based on Lazard's Levelized Cost of Storage Analysis v4.0: <https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf>.

²³ The range of roundtrip efficiency of hydrogen storage systems was estimated for 2040 by assuming an electrolyzer efficiency (HHV) of 76% in the Optimistic case and 73% in the Conservative case, and a CCGT efficiency of 65% and CT efficiency of 50% based on MHPs inputs.

In longer-duration applications, however, Li-ion battery roundtrip efficiency quickly declines with increasing standby duration. In the future, it is possible that Li-ion batteries used for long duration energy shifting would be disconnected from the grid to avoid standby losses that result from keeping inverters and transformers energized, as this comprises a significant portion of the standby losses for Li-Ion systems. New advances in Li-Ion battery chemistry, such as using non-aqueous (solid-state) electrolytes may allow a greater range of battery temperatures without increased fire risk, compared to today's aqueous electrolyte chemistries. This would potentially significantly reduce standby Li-Ion storage facility losses by reducing HVAC energy use needed to keep batteries within a narrow temperature range.²⁴ In addition to standby losses, the higher energy capacity cost also makes Li-ion batteries less desirable than hydrogen storage for longer-duration applications, as shown in Figure 3-8.

Figure 3-8: Comparison of total leveled fixed costs of Li-ion batteries and hydrogen storage (electrolyzer + CCGT or CT) at increasing storage duration.



²⁴ We assessed the standby losses and the relative magnitude of different losses using data provided to E3 by MHPs.

The fixed costs in Figure 3-8 assume utilization of curtailed renewables and a system with electrolyzer and gas turbine (CCGT or CT) sized at a capacity ratio of 2.5 : 1. Figure 3-8 shows that the fixed cost of Li-ion batteries increases linearly with energy capacity (i.e., storage duration). In contrast, fixed costs of hydrogen storage systems are insensitive to storage duration, since the capital cost of salt cavern storage is a small fraction of the total costs.

3.5 Potential Market Revenue for “First-Mover” Long-Duration Hydrogen Storage Projects

The potential market revenue for a 1000 MW hydrogen storage project was estimated using E3’s RESTORE model. RESTORE’s price-taker assumption is generally valid for systems that are relatively small and thus do not impact market dynamics, which is true for new hydrogen storage projects entering the market today, as there do not yet exist other existing projects.

The RESTORE results are shown in Figure 3-9 and Figure 3-10. The system modeled in RESTORE is a 1000 MW hydrogen system with CCGT (Figure 3-9) or CT (Figure 3-10) participating in the Southern California (SP-15) market. Cost and performance assumptions are consistent with each vintage year modeled. The revenues include both energy and capacity values, leveled over 20 years starting from the year of installation, with the capacity value obtained from Aurora analysis. The costs represent the leveled fixed costs of a hydrogen storage system with MHPS electrolyzers and new gas turbines in the year of installation.

Figure 3-9: Estimated leveled revenues and capacity costs in California by vintage year, assuming 1000 MW hydrogen storage system with MHPS electrolyzer and CCGT, using MHPS costs.

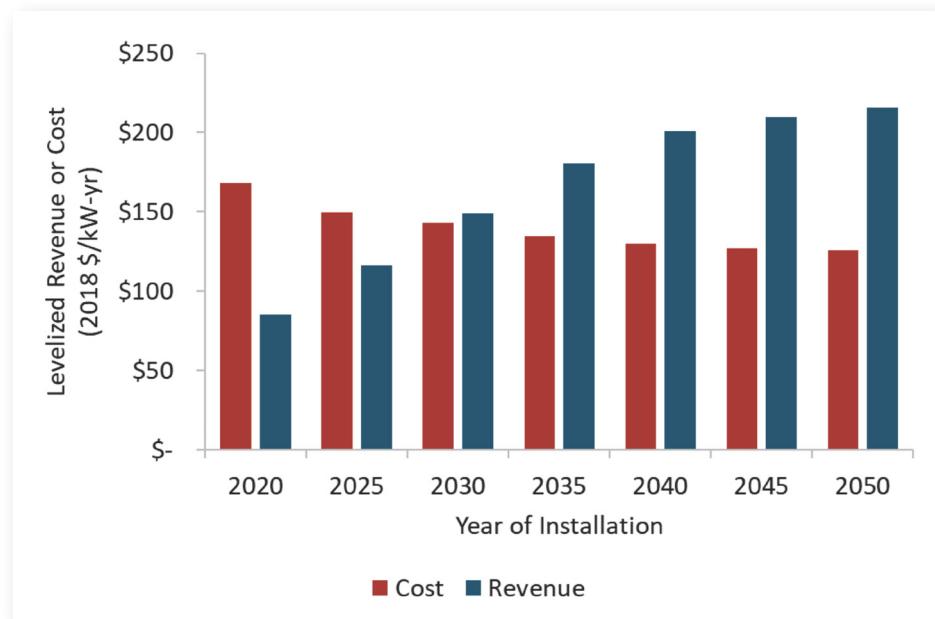


Figure 3-10: Estimated leveled revenues and capacity costs in California by vintage year, assuming 1000 MW hydrogen storage system with MHPS electrolyzer and CT, using MHPS costs.

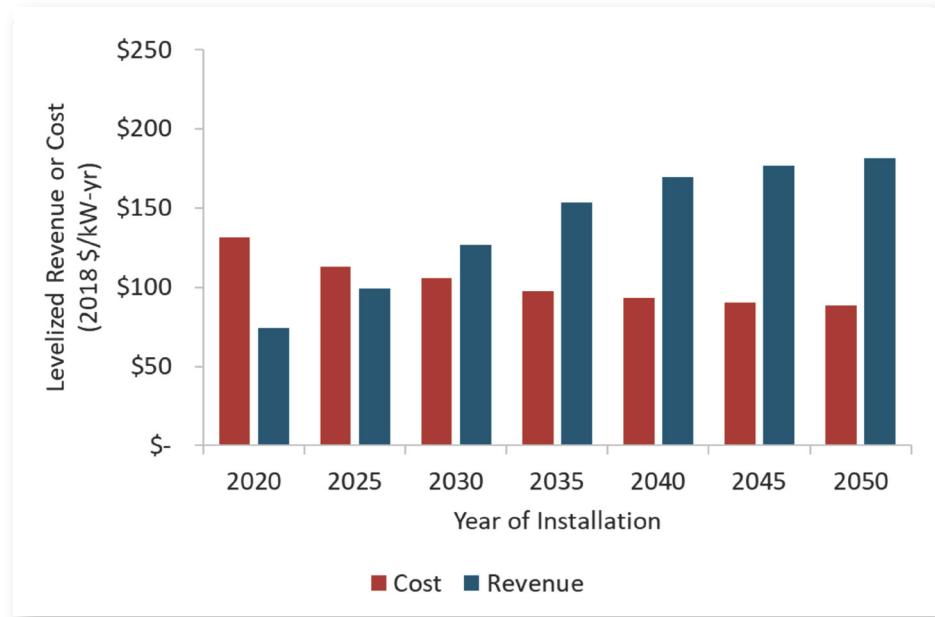


Figure 3-9 and Figure 3-10 show that a 1000 MW hydrogen storage system participating in the Southern California market becomes profitable (i.e., generating positive net revenues) if installed around 2025–2030 and later. The breakeven year for systems with CT could potentially be earlier than systems with CCGT, because the lower costs of CTs compensate for the lower energy revenues due to lower efficiencies.

3.6 Potential Hydrogen Market Size

To estimate the potential market size, E3 estimated the amount of economically viable long-duration hydrogen storage that could be produced from curtailed electricity.

Based on E3's modeling estimates of curtailment, E3 identified California and the Pacific Northwest as two markets with the most potential for curtailment utilization. The amount of curtailment that could be economically used by hydrogen storage systems, which is subject to the electricity prices and system size, implies the potential market size for hydrogen storage. Using E3's custom market equilibrium model introduced in Section 0 and E3's High RPS scenario in Aurora, analysis for 2035 and 2045 shows that:

- + The potential market size for hydrogen storage in California could be 1.5–10 GW, depending on the generation technology (CCGT or CT) and year (2035 or 2045).
- + The potential market size for hydrogen storage in the Pacific Northwest could reach 4 GW, primarily driven by capacity shortage in the region.

These estimates are based on cost inputs provided by MHPs and could change with technology cost and efficiency assumptions, as well as electricity prices and the availability of curtailed power.

The potential market sizes for hydrogen storage in California for systems installed in 2045 are shown in Figure 3-11 and Figure 3-12 (results for California for 2035 are shown in Figure 9-5 and Figure 9-6 in the Appendix). The energy revenues are determined from the market equilibrium model, and the capacity revenues are consistent with the capacity values in the RESTORE analysis. Using electrolyzer cost assumptions provided by MHPs, the economically viable market size is estimated to be 1.5–4.5 GW for installations in 2035, and 5–10 GW for installations in 2045. With the same generation technology, a hydrogen storage system installed in 2045 would provide higher energy revenues compared to one installed in 2035. This is because overall more curtailed power is available for charging in later years, suggesting larger arbitrage opportunities.

Figure 3-11: Levelized revenues and capacity costs as a function of cumulative installed capacity for hydrogen storage systems with CCGT installed in 2045 in California.

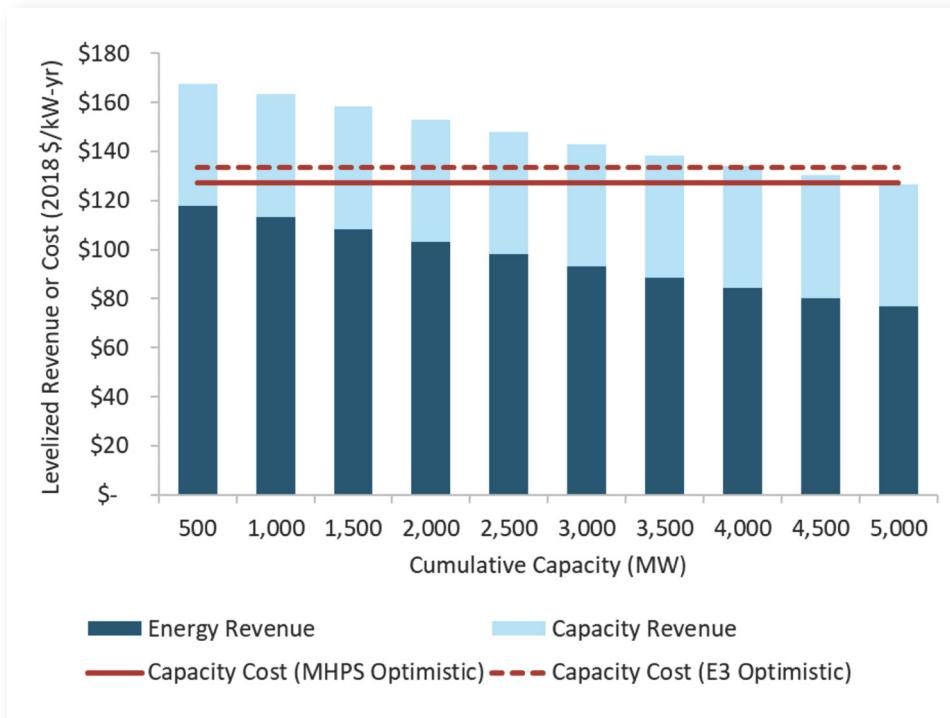
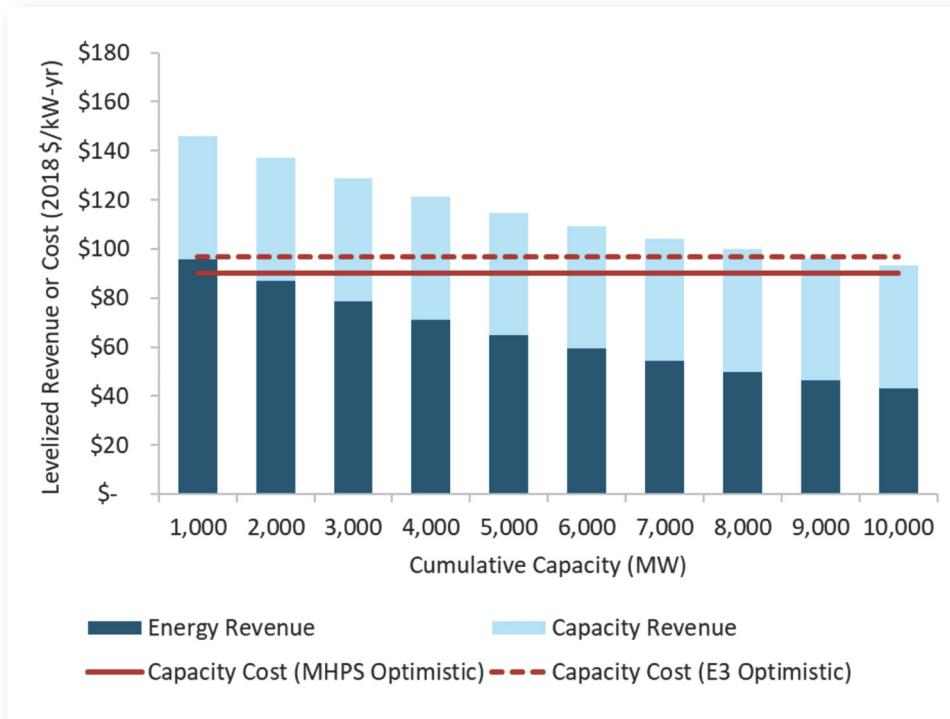


Figure 3-12: Levelized revenues and capacity costs as a function of cumulative installed capacity for hydrogen storage systems with CT installed in 2045 in California.

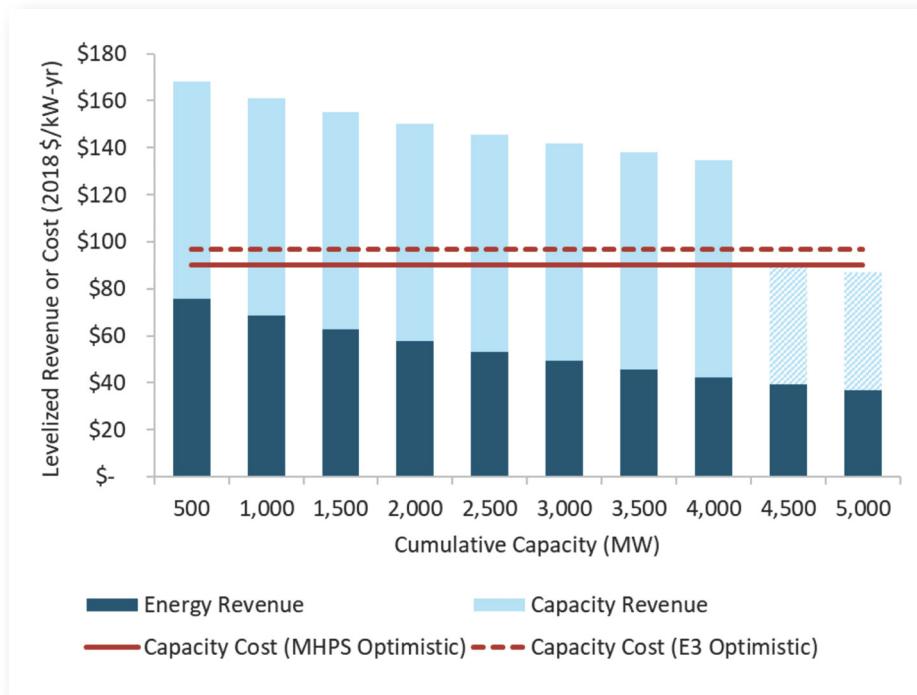


For storage systems installed in the same year, CT systems could potentially enable higher market potential, because the lower capital cost of CTs would more than make up for their lower efficiency compared to CCGTs. For this reason, the analysis for the Pacific Northwest focuses on CT systems, with 2045 results shown in Figure 3-13 (and 2035 results in Figure 9-7 in the Appendix).

Figure 3-13 shows that the potential market size for the Pacific Northwest could be up to about 4 GW, primarily driven by the capacity shortage in the region. The estimated shortage could change with load growth, such as electrification load and climate policy.

Unlike California, electricity prices rarely go below zero in the Pacific Northwest in the High RPS scenario, due to a lower reliance on solar and higher reliance on hydro for electricity generation in the Pacific Northwest than in California to meet clean energy goals. In addition, California still relies on natural gas in the evenings, while hydro in the Pacific Northwest operates in the evenings, which further reduces the price spreads in the Pacific Northwest, resulting in overall lower net energy revenues for storage systems. As a result, revenues of the hydrogen storage system are dominated by capacity value, with the caveat that future capacity market revenue is highly uncertain. For this analysis, when there exists a capacity shortage in the region, the capacity value of firm resources such as hydrogen storage is assumed to be the net-CONE (cost of new entry) of new CCGTs, assuming that CCGTs would be preferred over CTs to provide both energy and capacity due to the higher efficiencies of the former, as there is a current need to build new capacity in the Pacific Northwest. When the market is not capacity-short, the capacity value is assumed to be equal to the net-CONE of CTs, similar to the assumption for California.

Figure 3-13: Levelized revenues and capacity costs as a function of cumulative installed capacity for hydrogen storage systems with CT installed in 2045 in the Pacific Northwest.

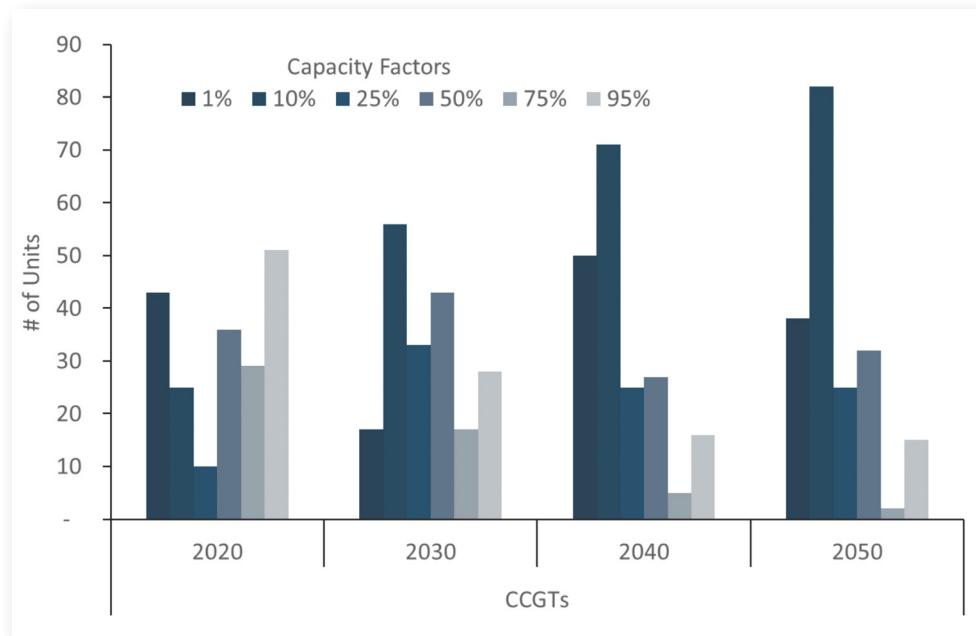


3.7 Potential Role of Gas Plants in Hydrogen-Fueled Power

E3's modeling to date has demonstrated the need for firm generating capacity to ensure electricity reliability in the West.²⁵ In particular, E3 has found that throughout the next decade, gas plants within in California and the Pacific Northwest will need to stay online as firm resources during times of low renewable generation. That said, E3's work in California, for example, finds that the utilization of gas plants in the West falls substantially over time. This pattern is consistent with the WECC-wide trend found in E3's High RPS forecast shown in Figure 3-14, which highlights the dramatic drop in CCGT capacity factors. In 2020, the majority of units operate at a capacity factor greater than 50%. By 2050, the majority have a capacity factor of 10% or less. We note that in reality, some of this gas capacity is expected to retire given uneconomic operations and the anticipated Li-ion battery storage buildup through the 2030s. Because Aurora does not model economic retirements, those units of gas capacity are not removed from the dataset below. In contrast, the most efficient gas plants post-2030 will earn the most significant energy margins in a shallow but volatile energy market that is dominated by renewable production.

²⁵ See, for example: "Natural Gas Distribution in California's Low-Carbon Future", CEC-500-2019-055-D, 2019. <https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/index.html>.

Figure 3-14: WECC-wide CCGT capacity factor trend (assuming 100% natural gas).



The lower utilization of gas plants, driven by inexpensive renewables and high clean energy requirements, may make these gas plants candidates for repowering with hydrogen. New combustion turbines are increasingly designed to burn a blend hydrogen and natural gas. This ability—to provide firm, dispatchable, low carbon power—fills the need for dispatchable zero-carbon resource found in existing E3 work.²⁶ E3 views combusting hydrogen in gas turbines as a potentially viable strategy to producing low-carbon firm power, assuming access to inexpensive hydrogen (e.g., due to falling electrolyzer costs) coupled with on-site geologic hydrogen storage, or delivered via dedicated hydrogen pipelines. Natural gas pipeline blend limits are limited to 7% hydrogen by energy (20% by volume). Future studies should be performed to evaluate the economics of varying levels of hydrogen blending in more detail to determine the optimum repowering strategy for specific existing plants beyond the ACES site evaluated herein.

²⁶ See, for example:

https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf
https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf

4 Hydrogen Outlook in Transportation

4.1 Hydrogen in Transportation Today

Today, the direct use of hydrogen in the United States transportation sector is concentrated in California, accounting for around 2 TMT/year. This small but growing market of light-duty hydrogen fuel cell vehicles (HFCVs) is centered around hydrogen refueling stations in the San Francisco Bay and LA regions²⁷. Under deep decarbonization carbon targets, E3 estimates that there is significant potential for hydrogen to enable decarbonization in heavy-duty vehicle transportation. While light-duty battery electric vehicles (BEVs) are operationally cheaper than HFCVs, their battery weight and charging requirements mean that HCFV's are potentially better positioned to enable a carbon constrained heavy-duty vehicle market. However, to realize this potential, hydrogen demand and production need to be scaled up in order to generate a substantial reduction in station costs.

4.2 Pump Price Comparison

The following tables compare light-duty and heavy-duty hydrogen vehicles with that of their major competitors, standard gasoline/diesel vehicles and BEVs. Today's hydrogen pump price in California is about \$13-16/kg.²⁸

4.2.1 Light-Duty Vehicles

The table below highlights the major characteristics of light-duty HFCVs and their main competitors, BEVs and standard gasoline vehicles. HFCVs can refuel in under 10 minutes, significantly shorter than a standard BEV which typically takes four to six hours on a Level 2 charger. However, HFCV's refueling cost is the equivalent of around \$14.50/gallon of gasoline, approximately three and four times that of a BEV and standard gasoline vehicle, respectively. Dividing each vehicles' refueling cost by their fuel economy, one arrives at their operating cost. As seen in Table 4-1, despite hydrogen having a high fuel economy, its operational cost is significantly greater than that of a BEV and double that a standard gasoline vehicle.

²⁷ California Air Resources Board. Annual Evaluation of Fuel Cell Electric Vehicle Deployment & Hydrogen Fuel Station Development. 2019. https://ww2.arb.ca.gov/sites/default/files/2019-07/AB8_report_2019_Final.pdf

²⁸ Equivalent to about \$13-\$16/gallon of gasoline.

Table 4-1: Current costs of light-duty vehicles in California.

	HFCV	BEV	Gasoline
Propulsion	Electric motor + H ₂ fuel cell + battery	Electric motor + battery	Internal combustion engine
Fueling			
<i>Fuel</i>	High pressure H ₂ gas	Recharge with electricity	Gasoline
<i>Time</i>	3-7 minutes (passenger vehicle)	4-6 hours on Type 2, 45 minutes on Supercharger	1-3 minutes
<i>Type</i>	35 MPa & 70 MPa compressed gaseous H ₂ storage	120-220 V	87 octane unleaded gas
City Economy	66 miles/gal ²⁹	0.26 kWh/miles ³⁰	32 miles/gal ³¹
Est. AV City Economy	47 miles/gal ³³	0.40 kWh/miles ²⁰	23 miles/gal ²⁰
Range (non-AV)	310 miles ¹⁵	240 miles ¹⁶	400 miles ⁷
Est. Range (AV)	220 miles	150 miles	280 miles
Purchase Price	\$59k	\$36k	\$19k
Refueling Cost			
<i>Price</i>	\$12.85-\$16.00/kg	\$0.16/kWh	\$3.00-\$4.00
<i>Gas Equivalent</i>	\$12.85-\$16.00/gal	\$5.30/gal	\$3.50/gal
Op. Cost (non-AV)	\$0.22/mile	\$0.04/mile	\$0.11/mile
Emissions	Car itself is zero emissions. Associated emissions are with the H ₂ production and delivery	Car itself is zero emissions. Associated emissions are with the charging generation mix	Avg 400 grams CO ₂ /mile

For light-duty HFCVs to be equivalent to the operating cost of a standard gasoline vehicle, their refueling price would need to fall to ~\$7.30/kg. If hydrogen costs \$7.30/kg, assuming a fuel economy of 66 miles/kg, a light-duty HFCV is operationally cost-equivalent (\$0.11/mile) to that of a standard gasoline vehicle. To be competitive with light-duty BEVs, the pump price of hydrogen would likely need to fall to under \$3.00/kg. Given the significant required drop in fuel price, it is anticipated that light-duty BEVs will be the preferred low-carbon technology to replace light-duty gasoline vehicles.

²⁹ Based on the 2019 Toyota Mirai, <https://www.fueleconomy.gov>

³⁰ Based on the Tesla Model 3, the most popular BEV sold in California, <https://www.fueleconomy.gov>

³¹ Based on the 2018 Honda Civic, the most popular passenger car sold in California, <https://www.fueleconomy.gov>

³² Autonomous vehicle

³³ Based on 20 mph average city traffic speed and 2.5kW AEV computer power draw

³⁴ Associated with fuel and electricity prices in California

4.2.2 Heavy-Duty Vehicles

The following table highlights the major characteristics of heavy-duty HFCVs and their main competitors, BEVs and standard diesel trucks. At the time of this analysis, heavy-duty alternatives to diesel trucks were not yet on the market^{35,36}. The comparison of their operating costs is based on the potentially optimistic technical specifications published by companies that were planning to release low-carbon alternatives to diesel heavy-duty trucking at the time of writing. A heavy-duty HFCV's refueling cost is equivalent to around \$13-16/gallon of diesel, which is approximately equal to projected costs for DCFC-charged heavy-duty BEVs, but four times that of a standard heavy-duty diesel vehicle.

E3's analysis includes the net cargo carrying capacity, as the weight of a battery is projected to significantly cut down the amount of cargo that heavy-duty BEVs could transport. This is calculated as the operating cost per mile divided by the maximum potential cargo weight. In the U.S., typical class 8 vehicles are limited to weigh no more than 80,000 lbs. Therefore, the cargo capacity for all three vehicles equals 80,000 lbs³⁷ minus their unladen curb weight. E3 has used engineering estimates to estimate unladen curb weight of future heavy-duty BEV and HFCVs.³⁸

³⁵ In this instance, E3 defines heavy-duty vehicles as Class 8 trucks, used in the long-distance delivery and transportation.

³⁶ These include the Toyota T60 HFCV, the Nikola One HFCV, the Tesla Semi BEV and the Volvo VNR BEV, all of which are expected to hit the market to some varying degree by late 2020. There is also the Nikola Two, a hybrid hydrogen-electric semi with a planned market launch of 2022

³⁷ https://ops.fhwa.dot.gov/freight/publications/brdg_frm_wghts/

³⁸ Unladen Curb weight for; HFCV = 22000 lbs, BEV = 45000, standard diesel = 21,000 lbs

Table 4-2: Cost and performance of heavy-duty vehicles compared in California (expected near-term).

	HFCV	BEVs	Diesel
Propulsion	Electric motor + H ₂ FC + battery	Electric motor + battery	Internal combustion engine
Fueling			
Fuel	High pressure H ₂ gas	Recharge with electricity	Diesel
Time	10 minutes ³⁹	40 minutes ⁴⁰	10 minutes ⁴¹
Economy non-Autonomous Vehicles	8.7 miles/kg ²³	2.0 kWh/mile ^{24,42}	7.0 miles/gal ²⁵
Est. Economy of AV	8.5 miles/kg	2.1 kWh/mile ²⁷	6.9 miles/gal ²⁷
Range	300-750 miles	500 miles	2000 miles
Purchase Price	\$375k ²³	\$175k ²⁴	\$150k ²⁵
Refueling Cost¹⁹			
Price	\$12.85-\$16.00/kg	\$0.34-\$0.78/kWh	\$4.00/gal
Diesel Equivalent	\$14.5-18.00/gal	\$12.80-\$29.00/gal	\$4.00/gal
Operating Cost, non AV	\$1.66-\$2.07/mile	\$0.68-\$1.56/mile	\$0.57/mile
Curb Weight	22,000 lb	45,000 lb	21,000 lb
Fuel Operating Cost (\$/ton-mi, Low Cost Bound)	\$0.05/ton-mile	\$0.04/ton-mile	\$0.02/ton-mile
Fuel Operating Cost (\$/ton-mi, High Cost Bound)	\$0.06/ton-mile	\$0.09/ton-mile	\$0.02/ton-mile

As seen in Table 4-2, despite heavy-duty HFCVs having a higher fuel price, their operating cost per ton has a range equivalent to that of heavy-duty BEVs given their ability to carry double the cargo. On the lower bound, the pump price of hydrogen would only need to fall to around \$11/kg for a heavy-duty HFCV to be equivalent to the operating cost (\$/ton-mile) of BEV Class 8 Truck. In order to be competitive with a standard diesel Class 8, the pump price would need to fall to around \$5/kg. Outside of stringent carbon requirements, it is plausible that hydrogen pump prices could fall several dollars such that they are more economical than BEVs. Therefore, if an economy is expected to meet its decarbonization goals it is feasible that heavy-duty HFCV will replace standard diesel trucks.

³⁹ Based on the Nikola One HFCV - <https://nikolamotor.com/one>

⁴⁰ Based on the Tesla "Semi" - <https://www.tesla.com/semi>

⁴¹ Average Class 8 Diesel Heavy-duty truck

⁴² Based on E3 Internal PATHWAYS Development

⁴³ Based on AEV Computing Power Draw of 2.5kW and average truck speed of 48 mph

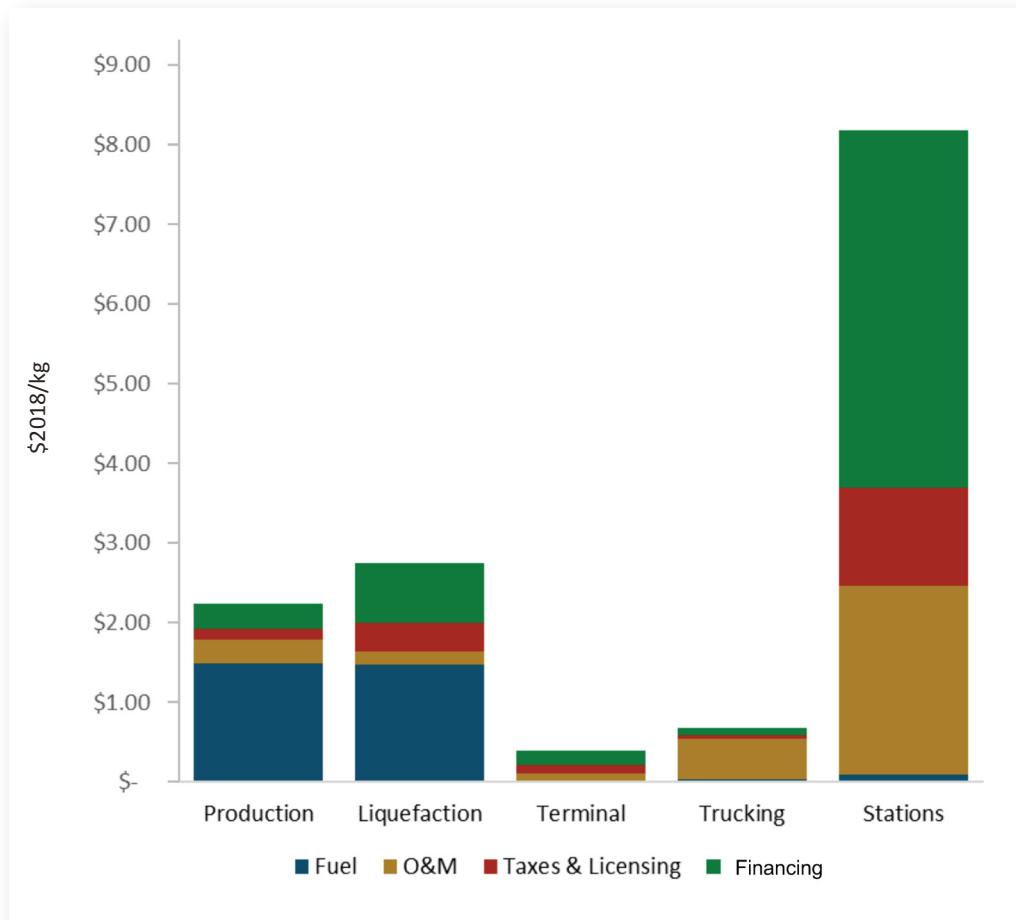
4.3 Breakdown of Pump Price

The biggest barrier to a robust hydrogen market in transportation today is the pump price of hydrogen, which is based on the delivered price of hydrogen to the refueling station. To better understand the potential for reductions in the pump price, E3 assessed the cost components of the price, based on data developed by the U.S. Department of Energy's (DOE) Hydrogen and Fuel Cells Program.⁴⁴ The DOE's calculator provided E3 with a breakdown of the pump price into five major components, as shown in Figure 4-1 below. The figure illustrates that station costs make up over 50% of the total pump price, over \$8/kg. In particular, the capital costs largely drive the station costs. The station costs are particularly high given low utilization. Thus, E3 believes there are substantial opportunities to lower the pump price for hydrogen. Under optimistic station sizing assumptions, E3 estimates that building fewer but larger stations (2,000 kg/day) with a utilization rate of 80 percent could enable reductions in the station price of \$3-\$5/kg. Coupled with less trucking and terminal needs for fewer, larger stations could see a resulting pump price fall by \$4-\$6/kg. Although this reduction in pump price is unlikely to make light-duty HFCV competitive, a significant realized reduction in station cost could make heavy-duty HFCV the most economical carbon-free heavy-duty trucking option.

Other cost components of the pump price will have smaller but still potentially significant impacts on the overall pump price. The cost of the fuel itself (electricity, natural gas, and hydrogen) make up the majority of the production and liquefaction costs. The method of production itself, while having the ability to shift pump prices down, would not be significant enough to make the total hydrogen pump price competitive with equivalent gasoline and BEV refueling. Rather, future pump prices will largely be dependent on the shift in station costs described above.

⁴⁴ https://www.hydrogen.energy.gov/pdfs/19001_hydrogen_liquefaction_costs.pdf. The DOE integrates financial data on refueling stations and hydrogen production into their Hydrogen Analysis (H₂A) production model and Hydrogen Delivery Scenario Analysis Model (HDSAM) in order to determine capital costs for production, liquefaction, terminal, trucking, and stations. They fed these capital costs into their Hydrogen Financial Analysis Scenario Tool (H2FAST) to break down the full pump price by supply chain.

Figure 4-1: Estimated hydrogen pump price breakdown in California, based on DOE research.⁴⁵



At the time of this study, 44 hydrogen refueling stations were operating in California, largely centered around the Bay Area and LA region.⁴⁶ In comparison there were around 2,700 DC Fast Charging stations for BEVs in California at the end of 2018. One of the key policy drivers for station construction has been California's Assembly Bill 8 (AB8) in which the California Energy Commission (CEC) has been required to allocate \$20 million dollars per year to fund at least 100 hydrogen fueling stations by 2024.⁴⁷ All stations in operations have taken advantage of this funding, and there are twenty stations currently in permitting, approval, or construction process.

⁴⁵ The data in this figure is based on E3 analysis of DOE's H2FAST modeling of the California hydrogen supply chain. The model assumes the hydrogen is produced through natural gas SMR, as it the most widely used hydrogen production today. It also assumes that the hydrogen is liquefied and transported by trucking which is the common long-distance form of transported hydrogen.

⁴⁶ <https://cafcp.org/stationmap>

⁴⁷ A.B. 8, 2013 (Cal. 2013)

In addition to AB8, California's Low Carbon Fuel Standard (LCFS) provides two potential credits for hydrogen fueling stations. The first is a standard credit, which is based on the throughput of hydrogen sold at fueling stations or hydrogen produced in California. Assuming a carbon intensity of 75 gCO₂e/MJ, a standard LCFS credit is worth about \$1.44/kg for a light-duty vehicle. The second credit is the Hydrogen Refueling Infrastructure (HRI) credit, which allows eligible hydrogen station operators to generate LCFS credits based on the difference between the station's installed capacity and the actual hydrogen throughput. That is due to the lack of HFCVs on the road; this credit is meant to support stations that are not generating the standard LCFS.⁴⁸ A key qualification of the HRI is that 40% of the hydrogen dispensed has to originate from a renewable content source. California's recent executive orders (B-48-18 and N-19-19) seek to achieve 200 hydrogen refueling stations by 2025.

4.4 Outlook for Hydrogen in Transportation

E3's view is that heavy-duty trucking offers the best opportunity for the utilization of hydrogen as economies seek to decarbonize, given their superior performance characteristics and competitive costs. In comparison to BEVs, they can be refueled in minutes as opposed to hours and can carry as much weight as a standard diesel truck as opposed to heavy-duty BEVs whose carrying capacity is cut in half due to the curb weight of the battery. Additionally, as most long-haul freight occurs over major highways, integrating hydrogen refueling stations at current truck stops in the West is technically very feasible.

Across all three of E3's PATHWAYS scenarios, HFCVs in heavy-duty trucking are expected to be competitive with the alternatives, as shown in Figure 4-2. In the Mid-Hydrogen scenario, E3 estimates hydrogen demand based on its assessment that hydrogen can compete in heavy-duty vehicles only, capturing 50% of heavy-duty vehicle sales by 2045. In the High-Hydrogen case, E3 believes that hydrogen can scale in heavy-duty vehicles more quickly and also capture some share of light-duty passenger vehicle sales. Finally, in the Transformative scenario, E3 assumes that hydrogen can capture nearly half of light-duty sales and 70% of heavy-duty sales in 2045. This assessment is based on the idea that if hydrogen production scales significantly, station prices will fall, making hydrogen more competitive.

⁴⁸ I.e. when fuel sales are equal to the station capacity no HRI credits would be generated.

In terms of demand for renewable hydrogen, short-term hydrogen transportation demand goes up to 0.22 MMT in the Transformative scenario, i.e., under the most optimistic circumstances. By 2045, demand ranges from 1 MMT to 5 MMT depending on the scenario as shown in Figure 4-3 below.

Figure 4-2: Light-duty (passenger) and heavy-duty hydrogen fuel cell vehicles sales in E3 PATHWAYS modeling as percentage of total passenger or heavy-duty vehicle sales.

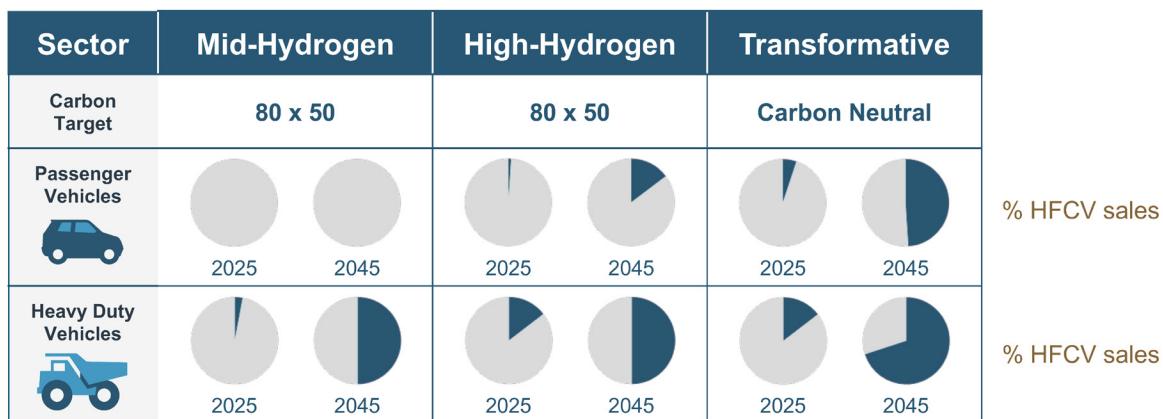
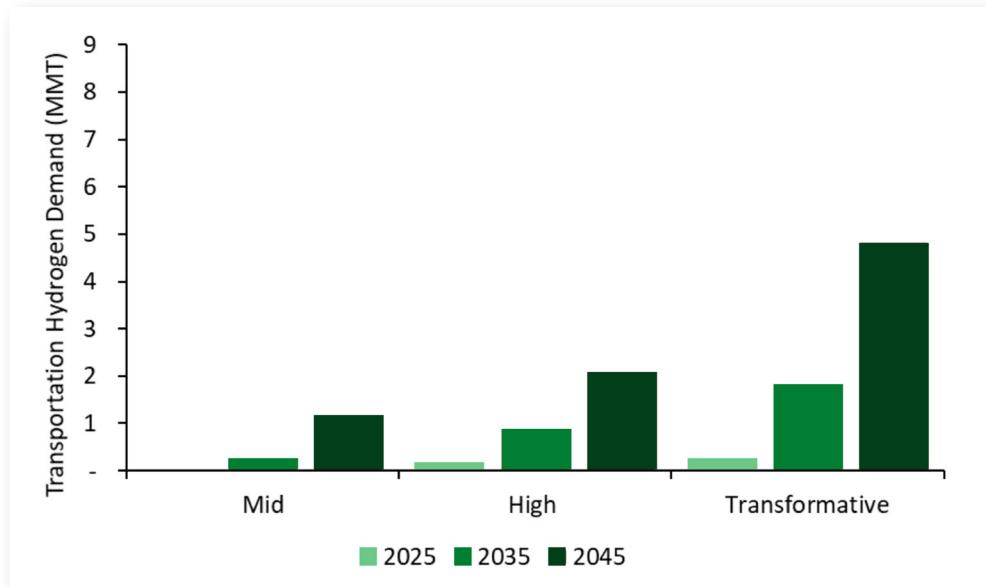


Figure 4-3: Total carbon-neutral hydrogen demand in the transportation sector in the Western U.S. estimated in PATHWAYS modeling under Mid, High, and Transformative scenarios in million metric tons.



Given the significant station costs, the primary challenge for heavy-duty HFCV will be building the necessary refueling infrastructure and lowering station costs. Due to economies of scale, the best way to lower station costs are to build larger stations with high utilization rates. Ultimately it comes down to incentivizing HFCVs on the road, leading to higher station utilization rates and lower pump prices.

5 Hydrogen's Outlook in Industry

5.1 Hydrogen in Industry Today

Today, hydrogen demand in the Western U.S. is dominated by the refinery sector. The majority of oil refining capacity and hydrogen production is located in California's Los Angeles Basin and San Francisco Bay Area.⁴⁹ There is a small amount of hydrogen production in Wyoming and Oregon that is used for manufacturing ammonia. As mentioned earlier in the report, virtually all hydrogen production is "brown" hydrogen. This is because producing hydrogen via SMR using natural gas feedstock is currently cheaper than alternative sources, and the SMR plants that feed refineries have been established for many decades.

Most hydrogen used in the oil refining and ammonia sectors is produced from the on-site production of hydrogen, via dedicated SMR facilities within these industrial plants. Owing to the lack of existing hydrogen pipeline infrastructure in the Western U.S., "merchant" plants that produce hydrogen outside of oil refineries and ammonia plants are typically located adjacent to those end uses. Existing industrial use of hydrogen is summarized in the table below.

⁴⁹ We note that significant hydrogen production occurs along the Gulf Coast, including for oil refining, ammonia production, and methanol production, but this was out of the geographic scope for this study.

Table 5 1: Existing industrial sector demand for hydrogen in the Western U.S.

Existing Industrial Sector Demand for Hydrogen, Thousand Metric Tons/yr				
State	Oil Refining - Captive	Oil Refining - Merchant	Ammonia Refining - Captive	Total by State
CA	3,240	220	0	3,460
WA	410	4	0	414
OR	0	0	20	20
MT	330	0	0	330
WY	180	0	70	250
NM	110	0	0	110
CO	70	0	0	70
Total by Sector	4,340	224	90	4,654

Sources: Based on EIA 2019 Refinery Capacity Report⁵⁰ and Form EIA-820, "Annual Refinery Report".⁵¹

5.2 Outlook for Hydrogen in Industry

In a deeply decarbonized future, E3 anticipates that demand for brown hydrogen will fall while demand for zero carbon hydrogen (i.e., green, blue, or pink) will grow. Given that the majority of brown hydrogen is currently used for oil refining, and given the extensive decarbonization of the transportation sector required for an 80% by 2050 world, E3 expects the demand for brown hydrogen to fall with time. However, E3 thinks that green hydrogen use may climb as the industrial and heavy-duty ground transportation sectors are decarbonized.

Due to the heterogenous nature of industrial energy demands, it is still uncertain to what extent industrial decarbonization will be cost effectively achieved through direct electrification of industrial processes (which might require process redesigns and create stranded asset risk) or by mixing in hydrogen, or hydrogen-produced synthetic methane, into the input fuels used in industrial processes. Producing green hydrogen is generally more expensive on an energy basis than direct electrification due to efficiency losses in electrolyzers, but likely less expensive in terms of capital cost and equipment changes. Blue hydrogen may also be cheaper than some electrification measures that do not have efficiency gains from electrification.

⁵⁰ <https://www.eia.gov/petroleum/refinerycapacity/>

⁵¹ https://www.eia.gov/dnav/pet/PET_PNP_FEEDNG_K_A.htm

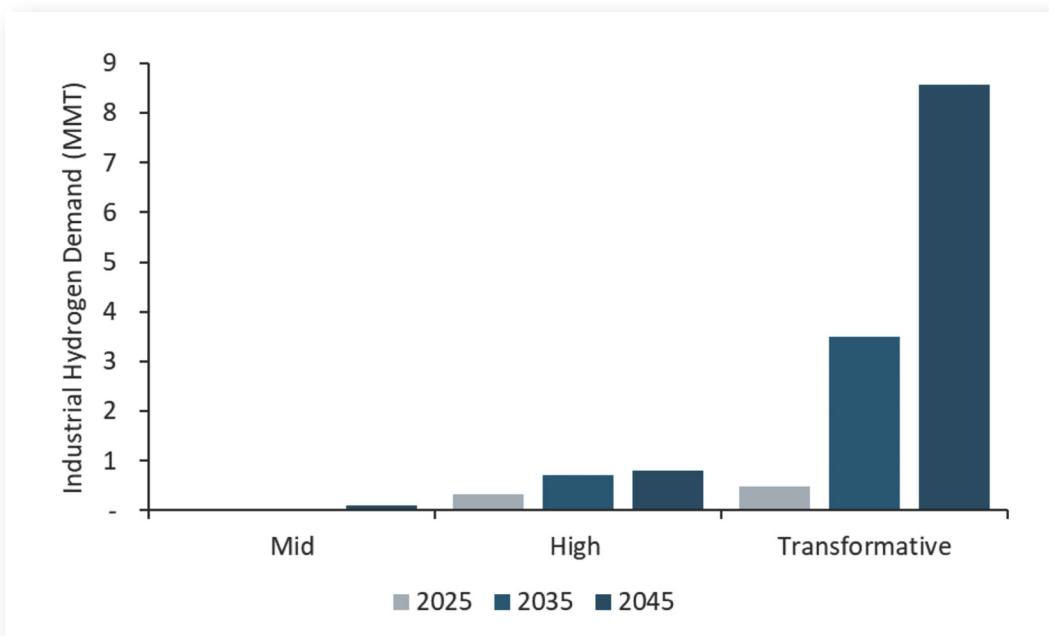
Hydrogen has the potential to directly displace natural gas and coal demand for process and heating applications where processes are not suitable for electrification. Future growth of a hydrogen market within the industry would likely be driven by high temperature applications (e.g. cement manufacturing), thermochemical applications (e.g. ammonia production) or as the basis for synthetic fuels. Yet, hydrogen can potentially be a replacement of natural gas for all heating applications and may prove a feasible option as infrastructure and equipment remain largely unchanged. In some high-temperature industrial processes (e.g., iron ore smelting, fertilizer production, and other hydrocarbon chemical production), carbon-neutral hydrogen offers the only known path for decarbonization while maintaining industrial process outputs. For example, current steel production primarily uses blast furnace and coke oven technology to produce the required feedstock of pig iron from iron ore. An alternative to this would be iron production via direct reduction of iron (DRI) using a combination of natural gas and hydrogen, which can decrease energy use and emissions but would require capital-intensive changes to the steel production processes. The DRI process can use hydrogen alone, but a mix of natural gas or synthesis gas is considered more favorable owing to the improved process economics and increased steel quality with the presence of CO. Experts suggest that a 30 percent mix of hydrogen with natural gas (by energy) is feasible without altering the production process.

As described in the executive summary, E3 constructed three PATHWAYS scenarios for the West. With regard to industry, the level of competitiveness of carbon-neutral hydrogen in these high temperature industrial applications is assumed to increase, reflecting the potential for growing demand. Short-term carbon-neutral hydrogen industry demand ranges from non-existent in the Mid-Hydrogen scenario to an optimistic case of 0.5 MMT in the Transformative Hydrogen scenario. By 2045, demand estimates significantly differ based on the scenario, from less than 1 MMT in both Mid and High-Hydrogen scenarios to over 8.5 MMT in Transformative, as shown in Figure 5-1 below. This would account for 25 percent of industrial energy demand.

Figure 5-1: Industry sector carbon-neutral hydrogen demand in E3 PATHWAYS modeling as percentage of total sector energy demand.



Figure 5-2: Total carbon-neutral hydrogen demand in the industry sector in the Western U.S. estimated in PATHWAYS modeling under Mid, High, and Transformative scenarios in million metric tons.



Ultimately, the adoption of hydrogen in industrial sectors will come down to fuel cost, even under stringent carbon targets. As long as natural gas remains cheaper than electricity, it is likely more economical to use SMR+CCS than electrolysis.

6 Hydrogen's Outlook in Buildings

6.1 Space Heating in the West Today

Today, natural gas used in furnaces dominates energy use in buildings, given its lower cost (per unit of energy) than electricity.⁵² To date, hydrogen has not been used in buildings in the United States, given its greater costs, lack of supporting infrastructure, and the lack of decarbonization policy affecting heating fuels. Additionally, electric heat pumps can provide heating services more efficiently than gas furnaces, even in cold climates, making them competitive with gas furnaces in a deeply decarbonized future.

There is a potential role for hydrogen as a source of back-up fuel, to complement electrification in buildings, particularly in cold climates. Building heating demands are highly seasonal, with large peak heating loads coinciding with cold snaps. Under large-scale electrification these peak loads will shift creating peak capacity and potentially create resource adequacy challenges. Although modern heat pumps can function in cold climates, their efficiencies decline as temperature drops, ultimately resulting in not just a shift in peak load but larger peak loads. If hydrogen is used in these cold climates as a source of back-up heat, the peak electricity grid demand would be reduced while the majority of space heating load is met with electricity. The total costs associated with retrofitting the gas pipeline infrastructure necessary to deliver hydrogen in these colder climates, however, would likely be high, and was not investigated in detail in this study.

⁵² Note this doesn't include any externality cost of GHG emissions.

6.2 Outlook for Hydrogen in Buildings

As a potential decarbonization option in residential and commercial buildings, hydrogen could be used to decarbonize a variety of end uses which currently rely on gaseous or liquid fossil fuels, including space heating, water heating, and cooking. Technical analysis by NREL suggests hydrogen gas can be blended into the existing natural gas pipeline infrastructure at relatively low concentrations without triggering significant infrastructure upgrades to pipeline infrastructure and in end-use devices which are utilizing the pipeline infrastructure.⁵³ Increasing the pipeline blend requires upgrades to pipeline infrastructure and end-use appliances, and for reasons described above, E3 views both of these options as likely only under stringent carbon targets and if electrification were infeasible.

In E3's three PATHWAYS scenarios, the Mid-Hydrogen scenario assumes a future in which no hydrogen is used directly for end uses in buildings. This means there is no hydrogen blending in the distribution pipeline, and all current gas-fired end uses in buildings are either electrified or rely on natural gas or biogas. The High-Hydrogen scenario reflects pipeline blending of seven percent of hydrogen by energy content in the Northern part of the West. The seven percent blend limit is what we believe to be the amount achievable without triggering significant infrastructure upgrades for pipelines and end use devices. This is a scenario representing increased use of hydrogen as a decarbonization option without the building sector undergoing significant incremental infrastructure upgrades in the deliverability of hydrogen. The Transformative Hydrogen scenario assumes that a hydrogen future for building end uses is created, and hydrogen pipelines are used to decarbonize the building end uses in colder climates that are not easily electrified.

For context, current building energy use demand in the West is about 50 percent electricity, 43 percent natural gas, and the remainder from a variety of other fuels such as wood, diesel, and LPG. In the High-Hydrogen scenario, we assume that all space heaters and water heaters which currently use natural gas are replaced by very efficient gas-fired appliances that also burn a blend of hydrogen. In this scenario, households that rely on electric resistance heaters are switched to heat pumps. In the Transformative scenario, the share of end use devices relying on the pipeline distribution system is the same, but we assume the pipeline is distributing 100 percent hydrogen gas, instead of a 7 percent hydrogen blend. The resulting demand of hydrogen in the building sector as a whole can be seen in Figure 6-1 below.

⁵³ <https://www.nrel.gov/docs/fy13osti/51995.pdf>

Ultimately E3's PATHWAYS results show that hydrogen building demand only occurs in the buildings sector in the High and Transformative scenarios, given its relatively greater cost. The High-Hydrogen scenario sees roughly 0.5 MMT of hydrogen demand throughout 2025–2045, as shown in Figure 6-2. The Transformative scenario sees hydrogen demand grow from 0.4 MMT in 2025 to over 4 MMT by 2045. This accounts for roughly 20% of building energy demand in 2045. The remainder is electrification.

Figure 6-1: Building sector carbon-neutral hydrogen demand in E3 PATHWAYS modeling as percentage of total sector energy demand.

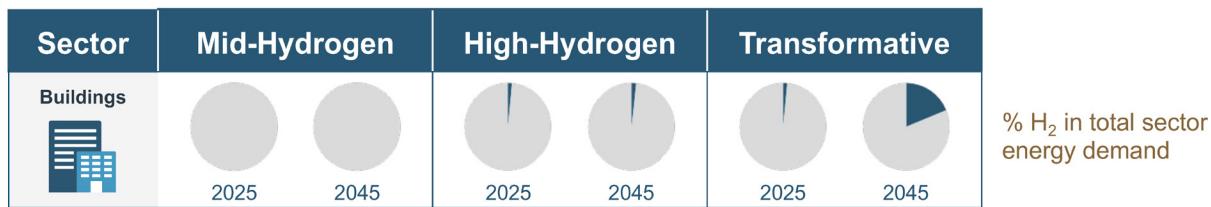
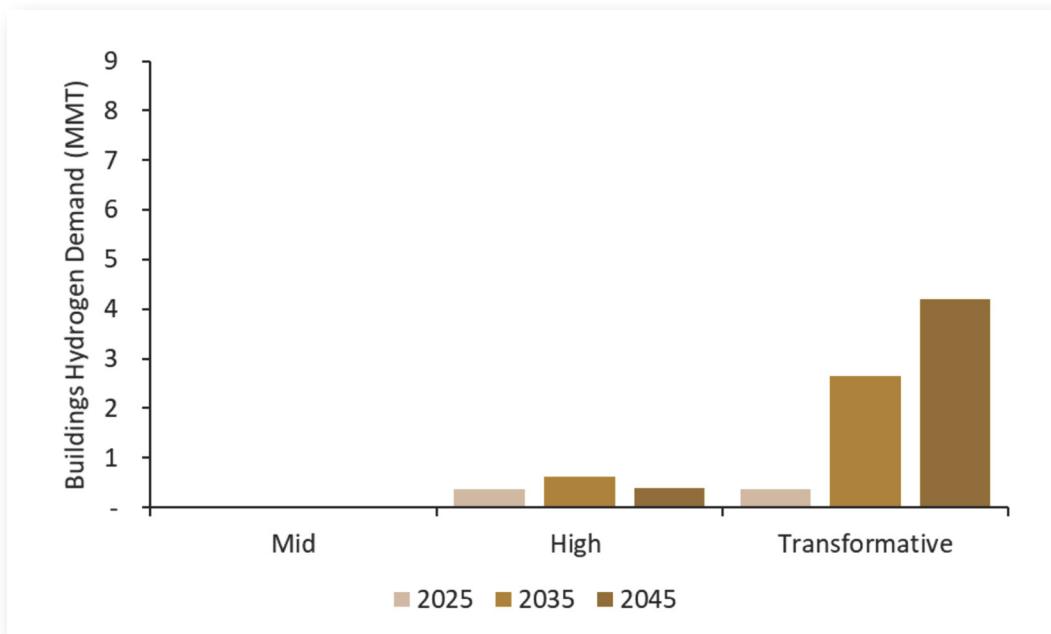


Figure 6-2: Total carbon-neutral hydrogen demand in the building sector in the Western U.S. estimated in PATHWAYS modeling under Mid, High, and Transformative scenarios in million metric tons.

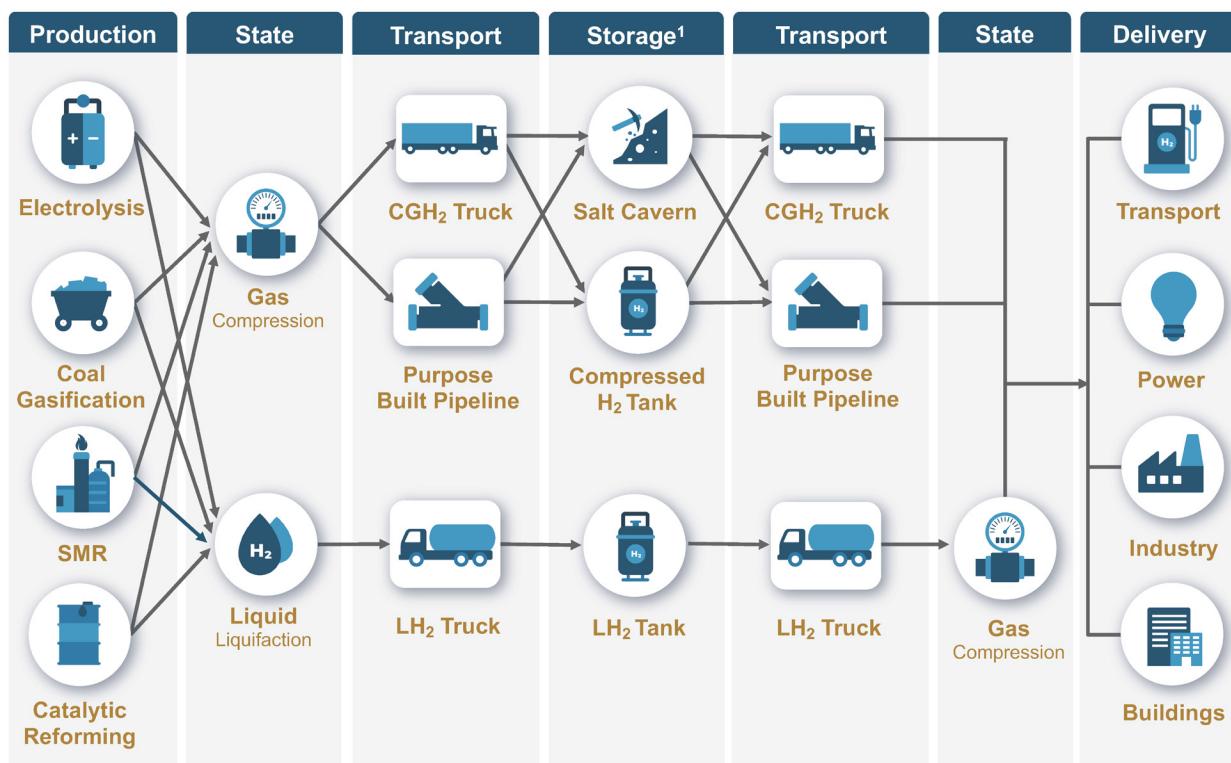


7 Hydrogen Supply Chain Overview

7.1 Mapping of the Current and Future Supply Chain

If hydrogen demand across any one sector grows, it will be highly dependent on the supply chain methods that store and transport it. Today more than 90 percent of hydrogen demand is captive, that is, it is produced deliberately or as a byproduct and reused on-site. Therefore, its supply chain is limited. Yet a successful hydrogen market will require the necessary infrastructure buildout. The following figure shows the current and most viable options available in the hydrogen market supply chain. Note that depending on where the hydrogen is produced and needed, certain stages (e.g., transportation) may be bypassed.

Figure 7-1: Current hydrogen market supply chain viable in WECC.



7.1.1 Production

As described in Section 2, hydrogen may be extracted from either water or hydrocarbons (e.g., natural gas), and the method of extraction affects whether the hydrogen generates associated emissions. In fact, of the four primary methods for hydrogen production, only electrolysis is zero carbon:

- + **Steam Methane Reforming (SMR):** Chemically reforming natural gas with heat and pressure to separate hydrogen from carbon.
- + **Catalytic Reforming:** Chemically reforming oil with a catalyst, heat, and pressure to separate hydrogen from carbon.
- + **Coal Gasification:** Combining water and coal at high pressure and temperature in order to break them into hydrogen, carbon dioxide (CO_2), and carbon monoxide (CO).
- + **Electrolysis:** Breaking water into hydrogen and oxygen using an electrical current.

The two commercially available non-fossil fuel derived hydrogen production technologies today are alkaline electrolysis and PEM electrolysis. PEM electrolysis has a faster response, allows for a greater operating pressure, a smaller footprint, and a resulting higher purity hydrogen. However, the technology is still relatively new and is more expensive due to the platinum requirements in the membrane. In fact, electrolysis makes up only four percent of global hydrogen production. In contrast, most of the hydrogen produced is captive where it is re-used on-site to make ammonia, methanol, ethylene, coke/iron, and within oil refineries. The rest is sold in markets to be used in oil refineries or manufacturing industries for food, glass, or electronic devices.

7.1.2 Transportation

The main current and potential hydrogen delivery options are trucks and pipelines⁵⁴. Trucks can transport gaseous and liquid hydrogen whereas pipelines would transport gaseous hydrogen.

⁵⁴ Shipping by train is technically feasible however no proposals or estimates exist. Delivering hydrogen by ship is also possible but is irrelevant for the WECC.

7.1.2.1 Trucking

Trucking compressed gas (CGH_2) is the most common form of hydrogen delivery today, and it is one of the cheapest options for shorter distances (300-400km). It consists of horizontal tubes or vertical containers that can contain 200-1,100 kg of hydrogen at a pressure of 250-500 bar. Liquid hydrogen (LH_2) trucks are the other common form of trucking, consisting of large well insulated tanks storing hydrogen at cryogenic temperatures (-253°C). The cost to liquify hydrogen is high, and thus it is more expensive at short distances. However, as liquid form hydrogen takes up less space, LH_2 trucks have a carrying capacity of 2,600-5,000 kg. Therefore, at distances greater than 400 km, they are more economical than CGH_2 .

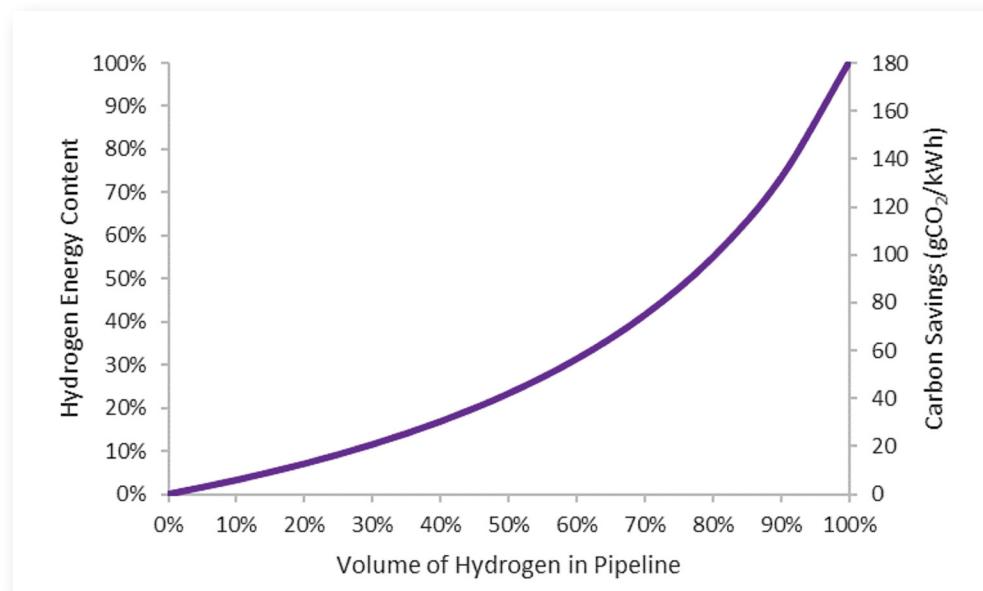
It is also possible to mix hydrogen with ammonia in order to transport it. Although the cheapest method over short distances and a high carrying capacity (up to 6,100 kg), ammonia is toxic with significant safety risks and pollution potential. Thus, this method will likely be only used within large industrial parks. A future trucking alternative is Liquid Organic H₂ Carrier trucks (LOHC), which allow hydrogen to remain liquid at normal conditions and thus can use standard gasoline or diesel trailer tanks as opposed to cryogenic insulated tanks. The technology is still relatively new and not commercialized.

7.1.2.2 Pipelines

Transporting hydrogen through pipelines is a viable strategy under a highly carbon constrained world that sees high hydrogen demand. In the short-term, it is possible to blend 5-20 percent by volume of hydrogen into the existing natural gas pipeline infrastructure without the need for costly retrofits or upgrades. Yet, most natural gas end uses cannot today handle a blended gas and would require updates to the appliances themselves. Additionally, due to the low energy density of hydrogen, it is not a 1:1 replacement of emissions when blended with natural gas. As seen in the figure below, a pipeline blended with 10 percent hydrogen⁵⁵ only saves about three percent on carbon emissions.

⁵⁵ Most counties regulations don't allow for more than 10 percent blending.

Figure 7-2: Hydrogen energy to volume content in natural gas blended pipeline.



As such, in the long-term, new purpose-built hydrogen pipelines would make more sense in a high hydrogen future. Despite having a very high capital cost, estimated by the DOE in range of \$0.8-\$1.15 million/km of steel, purpose-built lines would have low operating costs.⁵⁶ They are the cheapest way to transport over land under high hydrogen demand in which tens of thousands of kgs/day would be dispensed. E3 estimates a leveled pipeline cost from the ACES project location in Utah to a load center in LA to be \$0.25/kg.

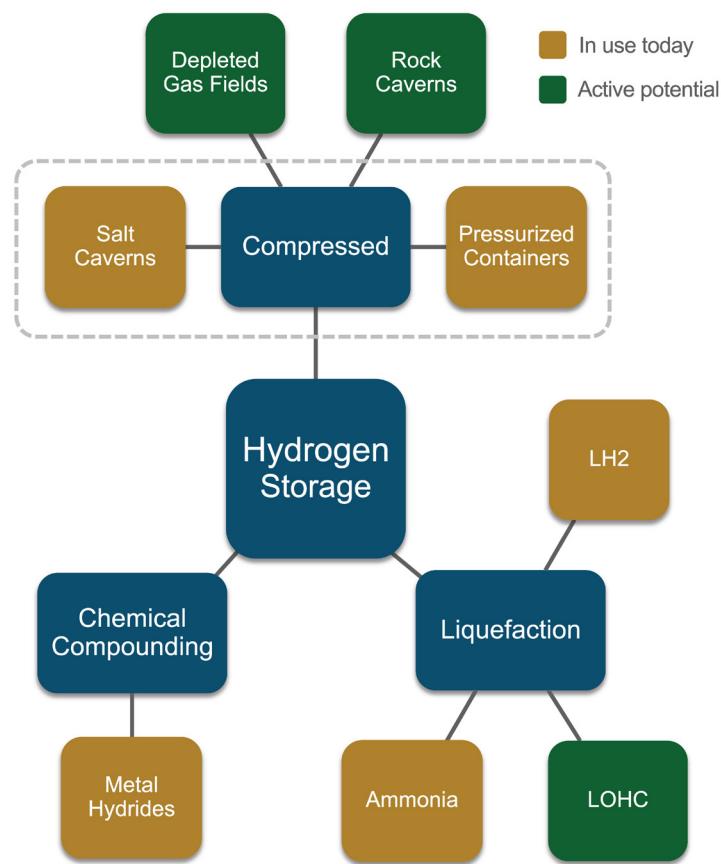
Purpose-built hydrogen pipelines do exist in the U.S. today, concentrated mostly in Texas and Louisiana, connecting refinery plants along the Gulf. However only 1,600 miles are in operation as opposed to the 300,000 miles of natural gas pipelines that span across the country.

7.1.3 Storage

Hydrogen will need to be stored in order to meet energy needs on-demand and, in regard to the power sector, to take advantage of arbitrage opportunities. Hydrogen contains some of the highest amounts of energy per weight but has an incredibly low density. This means that one kilogram hydrogen at normal conditions, i.e. in gaseous form, needs eight times as much storage space than a kilogram of natural gas. The following figure outlines the major forms of storage.

⁵⁶ Pipeline capital costs can be found in the DOE's HDSAM: <https://hdsam.es.anl.gov/index.php?content=hdsam>.

Figure 7-3: Hydrogen storage methods.



Salt caverns and pressured containers are the most common and viable forms of hydrogen today and in the future as outlined in green in the figure above. Pressurized containers will be needed for small short-term storage, i.e., refueling stations, as they can be filled, emptied, and transported easily. Geologic storage like salt caverns, consistent with what the ACES project will be utilizing, are the best form of large-scale long-term storage. Although limited by geography, caverns can store essentially unlimited hydrogen with limited losses. E3 estimates that the salt cavern used by ACES, for example, could achieve an estimated levelized cost of less than \$1.04/kg given the significant amount of storage.⁵⁷

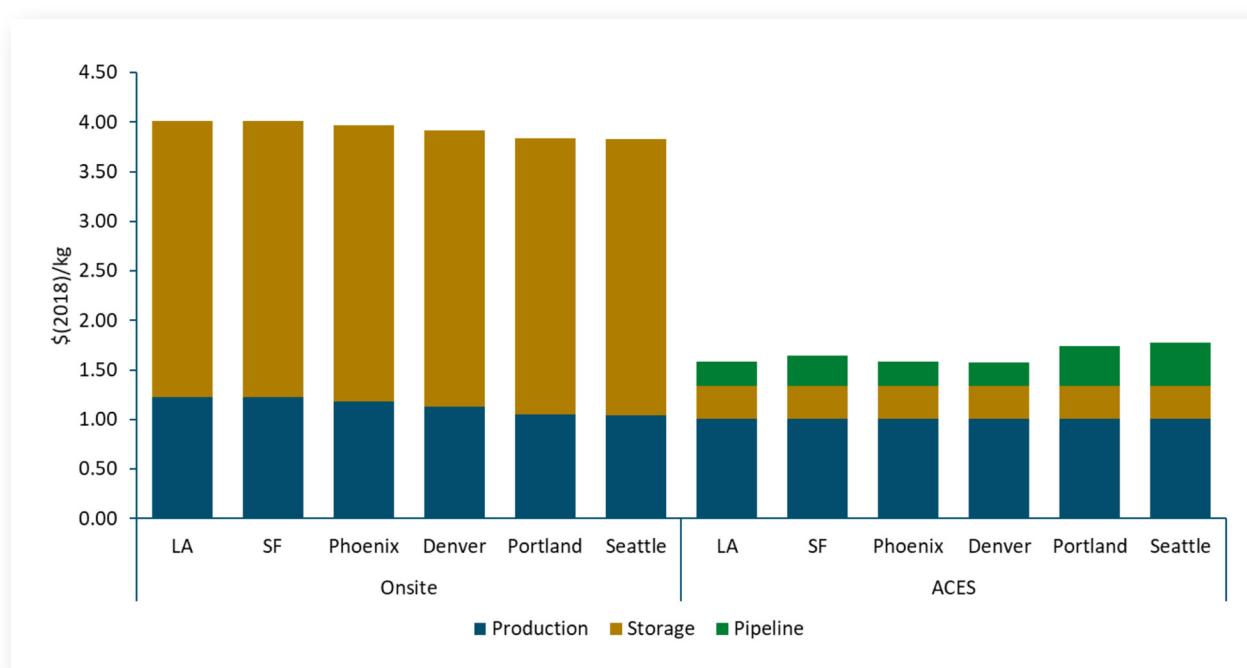
⁵⁷ This estimate is based on an initial reference capital cost of \$12.50/kg for a small storage facility (about 1,100 tons), and then assuming this capital cost can be scaled down to reflect the much larger storage size of a storage system like ACES. The initial capital cost and the scaling factors for a project like ACES were derived from the DOE H₂A model (<https://www.nrel.gov/hydrogen/h2a-production-models.html>).

7.2 Centralized versus Distributed Storage Methods

In a carbon constrained world that sees an expanded hydrogen market, current cost trajectories suggest that a centralized hydrogen supply chain is likely to be more cost effective than on-site, hydrogen production and small-scale, distributed hydrogen storage. In particular, it is far cheaper to store hydrogen at scale in large-scale, long-term storage options like salt caverns than on-site compression tanks, the only other commercially available storage technology, as seen in Figure 7-4, shown below.

Figure 7-4 compares the cost of producing hydrogen from off-grid solar either on-site at significant load centers in the West or at the ACES site in Utah. In Figure 7-4, production costs are based on MHPS capital cost estimates and E3/UCI electrolyzer learning curves, as reported in Section 2. On-site storage assumes the same level of hydrogen storage as the salt cavern in Delta, UT but in compressed tanks. Transportation only includes gas transmission pipelines from the major ACES site following major freeway routes.

Figure 7-4: Potential delivered leveled hydrogen costs in 2040 per hydrogen production cost assumptions provided by MHPS.



8 Conclusions

Hydrogen has emerged in policy discussions across the West as an attractive solution to the decarbonization challenge. As a versatile energy resource with characteristics similar to natural gas, hydrogen has the potential to support decarbonization across a range of end uses, particularly as long-duration energy storage in the electricity sector. To achieve ambitious near-complete economy and electricity sector decarbonization targets, hydrogen must build on existing momentum and continue to realize anticipated cost reductions. In particular, the key findings from this study include:

- + **The most promising and realistic opportunity for carbon-neutral hydrogen is as long-duration energy storage for the electricity sector in a deeply decarbonized West.** Hydrogen could provide valuable firm generation capacity and long-duration energy storage, in a deeply decarbonized, high renewable future. The relatively low cost of hydrogen storage in geologic formations allows large amounts of energy to be stored in the form of hydrogen and used for seasonal shifting of energy. This is particularly useful for providing firm zero-carbon electricity during multiday periods with low wind and solar power generation. Curtailed energy from renewables and the falling costs of dedicated off-grid renewable power may provide cost-effective energy resources. Finally, the ability to combust hydrogen in existing thermal power plants and to transport it (with some equipment retrofits) in existing natural gas pipelines may be useful in reducing typical system costs. Given the limited project scope, E3 did not compare the economics of long-duration hydrogen energy storage to other sources of zero-carbon firm power that may compete with hydrogen.
- + **Carbon-neutral hydrogen could play a role in decarbonizing other sectors of the economy, particularly heavy-duty ground transportation.** Due to the low load carrying capacity, significant charging times, and necessary charging infrastructure required for heavy duty battery electric vehicles (BEVs), hydrogen fuel cell vehicles (HFCVs) are an attractive candidate to replace diesel heavy-duty vehicles (HDVs) to enable carbon-free trucking. HFCVs are cost competitive with BEVs for heavy-duty trucking on an operating cost (per ton-mile) basis, given that hydrogen vehicles have about twice the carrying capacity, and may continue to improve that cost competitiveness with reductions in station costs. Still, HFCVs remain more expensive than diesel trucking, and thus growth of HFCVs will be most likely if specific strict bans or limits are placed on the sale or operation of diesel HDVs.

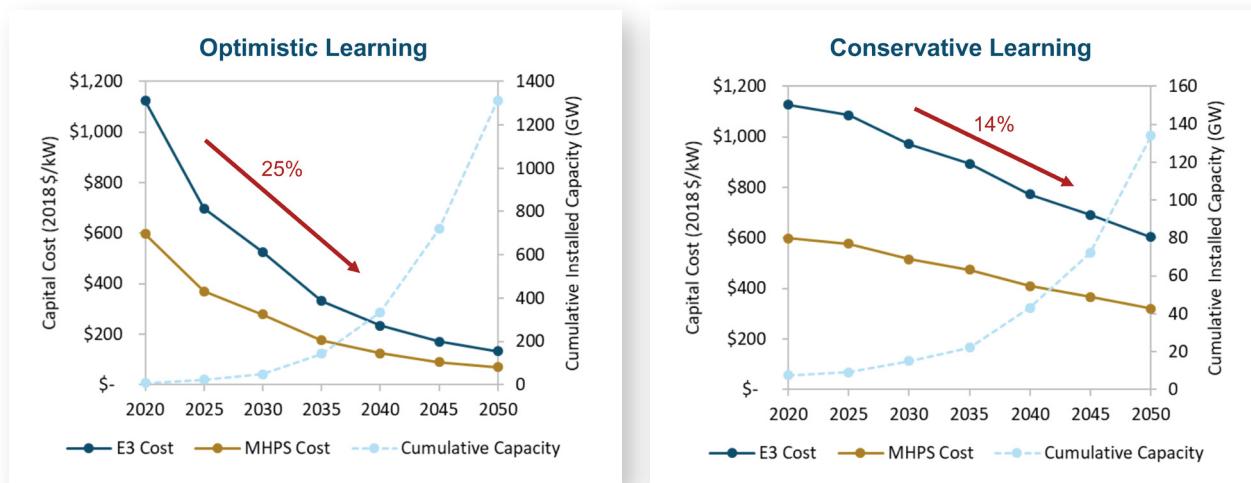
- + **Carbon-neutral hydrogen's role is uncertain in buildings and industry, with potential opportunities foreseeable if the Western U.S. achieves carbon targets close to complete decarbonization.** Hydrogen has advantages over other zero-carbon alternatives for building and industrial end uses, including its ability to be used, stored and distributed through similar means as natural gas. However, there are significant and uncertain costs associated with upgrading existing natural gas distribution pipelines to accommodate hydrogen blends much above 7% by energy (20% by volume). Furthermore, the use of hydrogen as a fuel in buildings may not be cost-competitive with electrification alternatives, particularly in Southern parts of the Western U.S. In industry, there are some applications in which carbon-neutral hydrogen is likely to be competitive with electrification alternatives (e.g. high process heat), however, both carbon-neutral hydrogen and electrification in industry remain relatively expensive, and there are currently limited policies in place today to push these industrial decarbonization strategies forward. Without stringent decarbonization targets it will be difficult for hydrogen to compete as a replacement to cheap natural gas and competing with electrification options in buildings faces major cost and implementation challenges.
- + **The most economic means of producing carbon-neutral hydrogen in the long run remains uncertain.** Until at least 2025, steam methane reforming (SMR) with 90% carbon capture and storage (CCS) is likely to be lower cost than electrolysis with renewable power, though project costs may be highly site-specific. However, by the mid-2030s, electrolysis with renewable power may become more economic, due to potentially rapid declines in electrolyzer costs, coupled with the availability of inexpensive renewables.
- + **When underground storage is available, centralized hydrogen production from renewables in locations with on-site storage is lower cost than decentralized hydrogen production from renewables.** Thus, locations with underground storage may serve as cost-effective energy “hubs”, providing hydrogen to locations without energy storage. If hydrogen is generated using zero carbon electricity, using centralized geologic hydrogen storage coupled with a network of hydrogen pipelines to deliver to multiple end users is more cost-effective than building a decentralized system with hydrogen storage at each end user’s site, with no hydrogen pipeline network.

9

Appendix

9.1 Additional Results

Figure 9-1: Learning curves for alkaline electrolyzers assumed in this study.



Notes:

1. The “E3 Cost” reflects the 2020 E3 estimate of the electrolyzer stack, the mechanical balance of plant, and the electrical balance of plant, but no installation costs. The “MHPS Cost” reflects the 2020 MHPS estimate of the electrolyzer stack, the mechanical balance of plant, and the electrical balance of plant, but no installation costs. The total installed electrolyzer cost would add an estimated 10% to the direct technology costs. Note that this excludes site-specific design, land, permitting, and contingency costs, which are significant additional costs but hard to quantify when costs are shared with other items, such as a combined cycle or combustion turbine, therefore these costs are not included in our assessment.
2. Optimistic and conservative learning curves were applied to the 2020 capital costs to estimate the costs of electrolyzers as cumulative capacity increases over time. Both the optimistic and conservative learning curves were developed by E3/UCI as part of the CEC retail gas study.

Figure 9-2: Breakdown of LCOE of hydrogen storage in 2040 for CT systems with MHPS capital cost and E3/UCI learning curve assumptions.

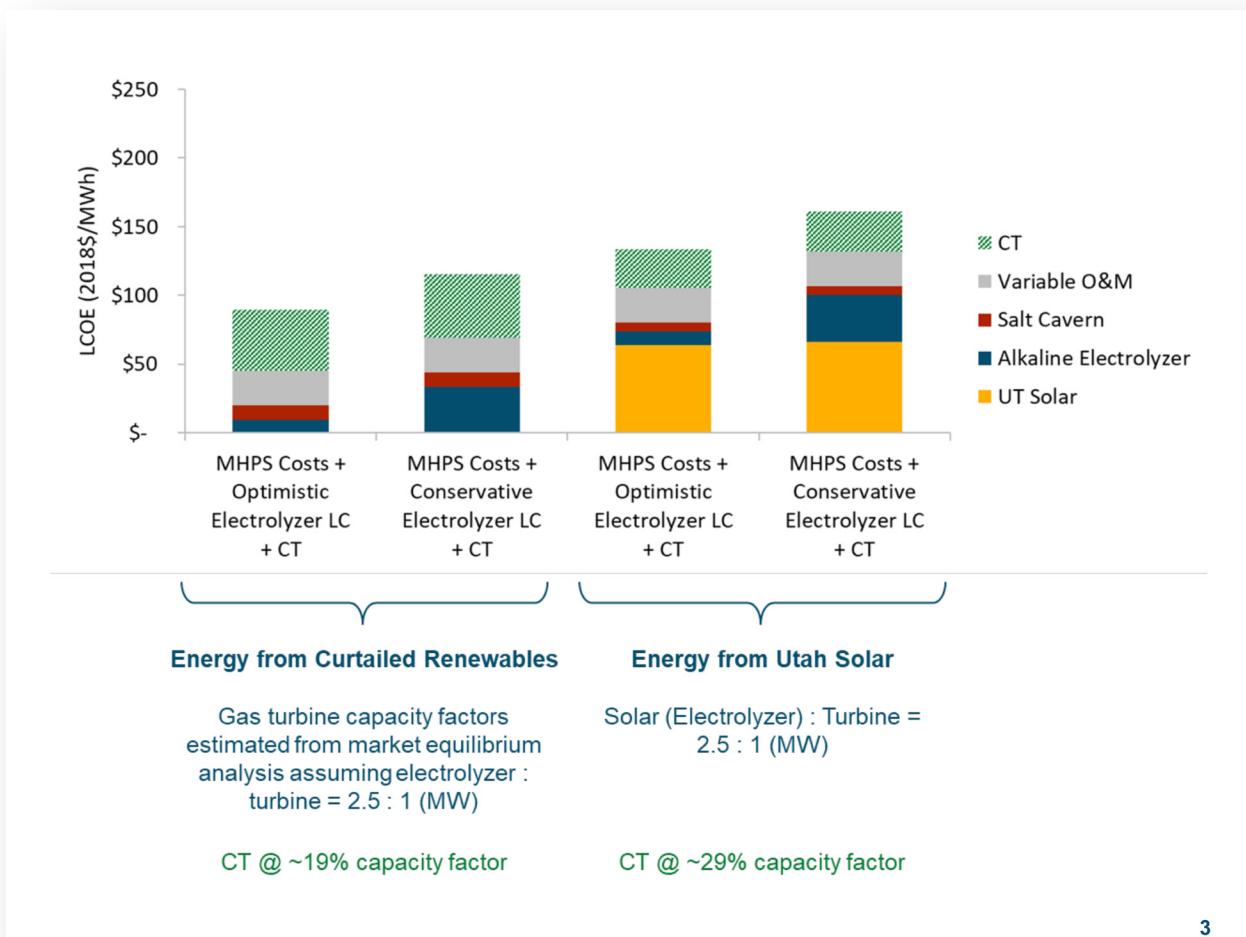
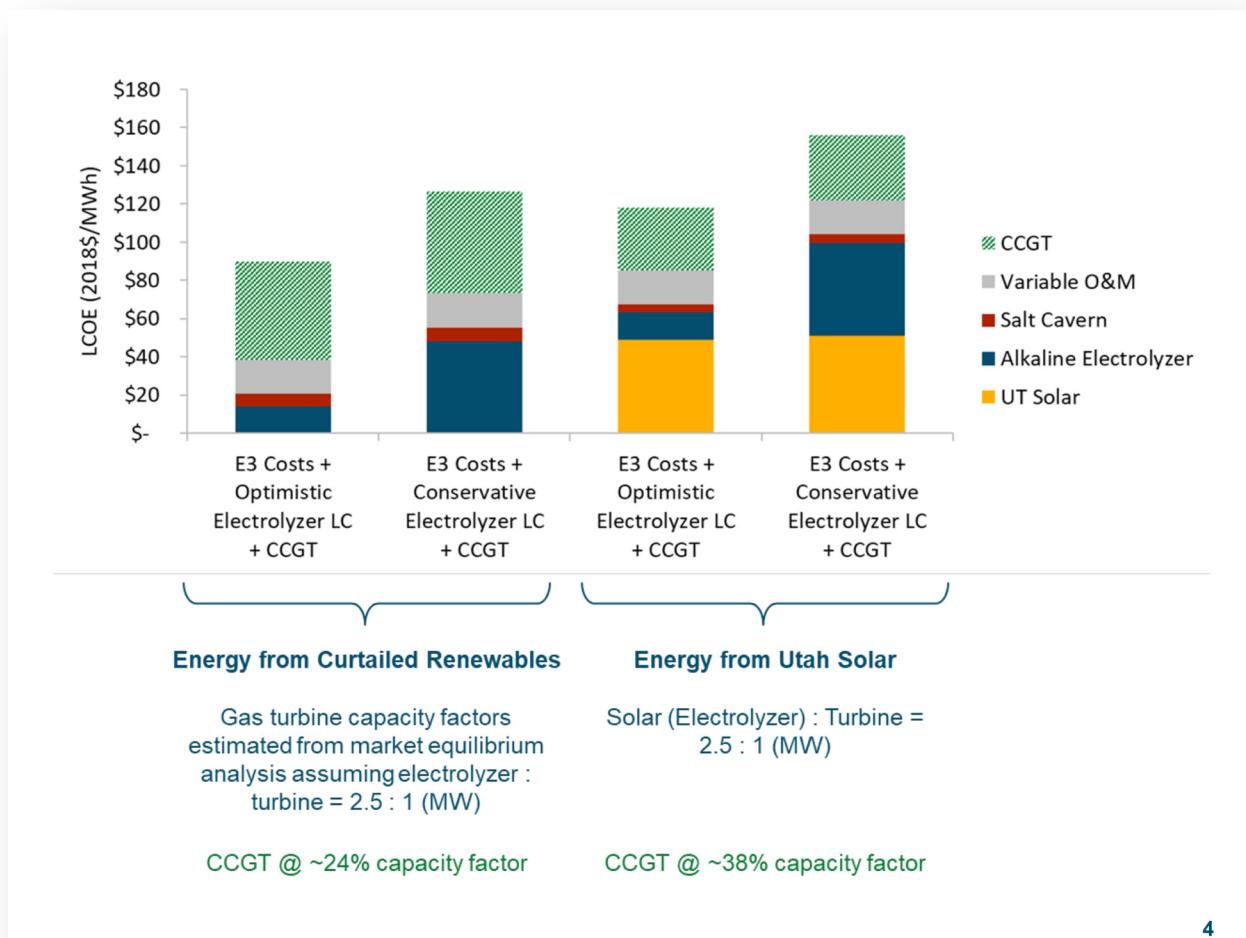


Figure 9-3: Breakdown of LCOE of hydrogen storage in 2040 for CCGT systems with E3 capital cost and learning curve assumptions.



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Figure 9-4: Breakdown of LCOE of hydrogen storage in 2040 for CT systems with E3 capital cost and learning curve assumptions.

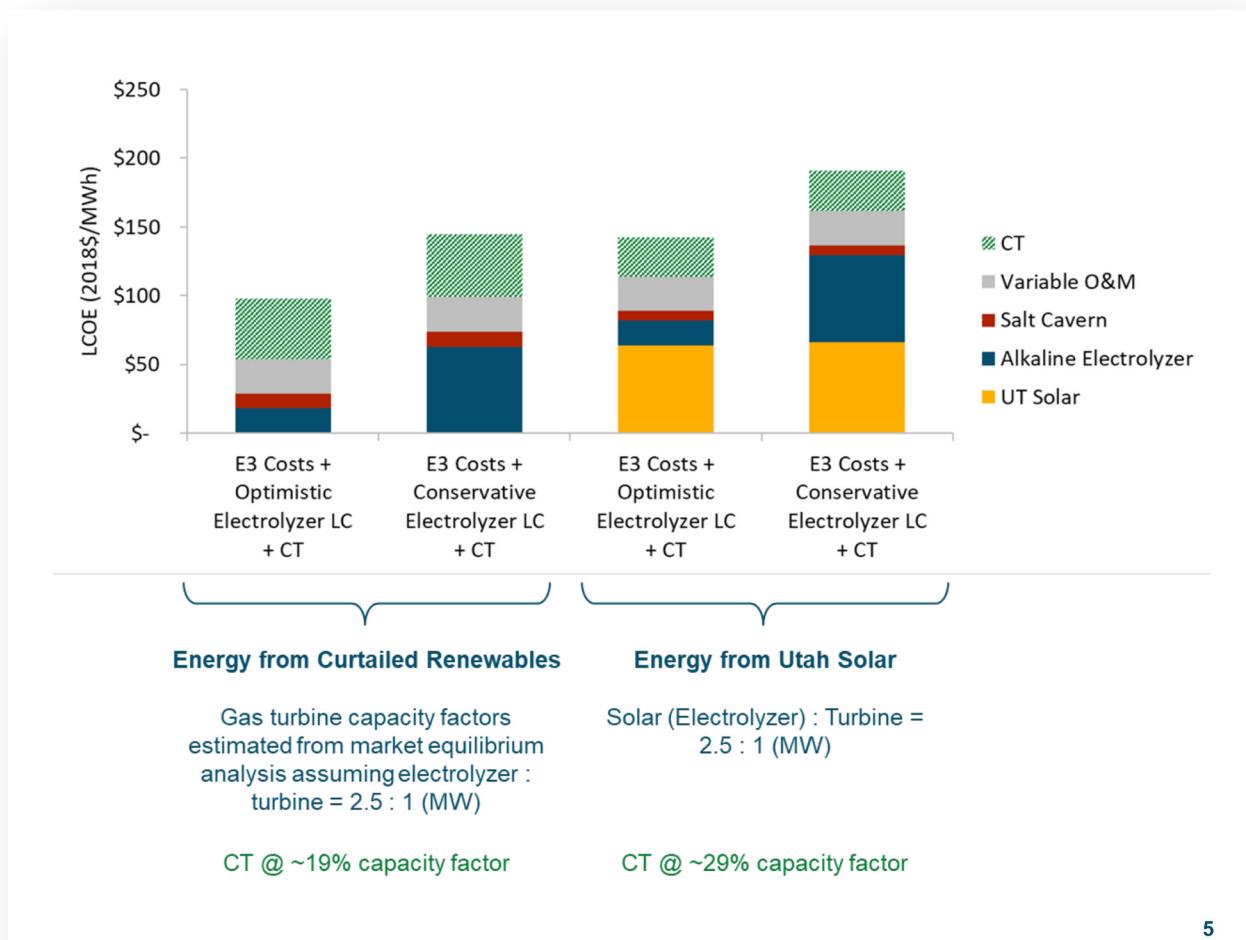
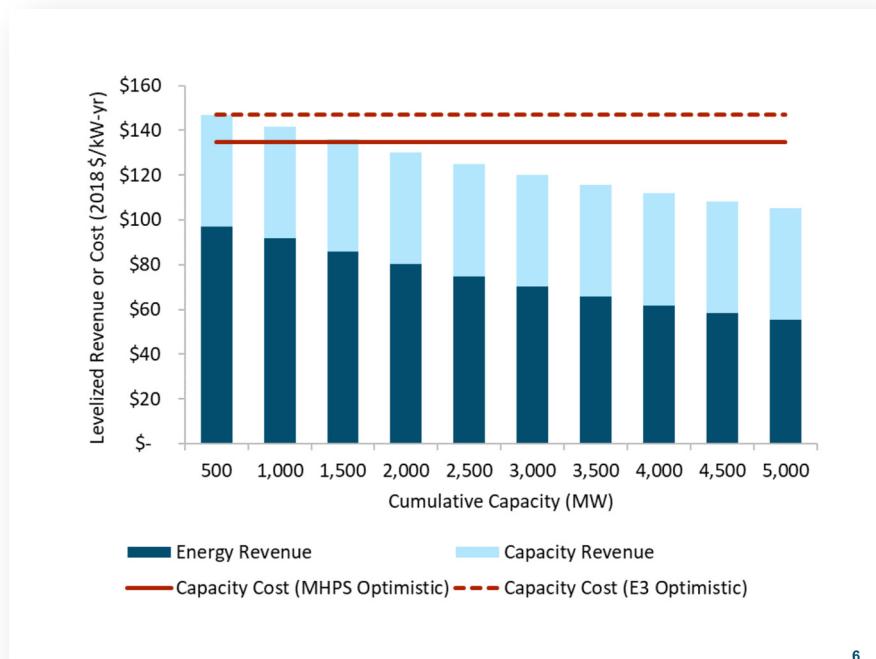
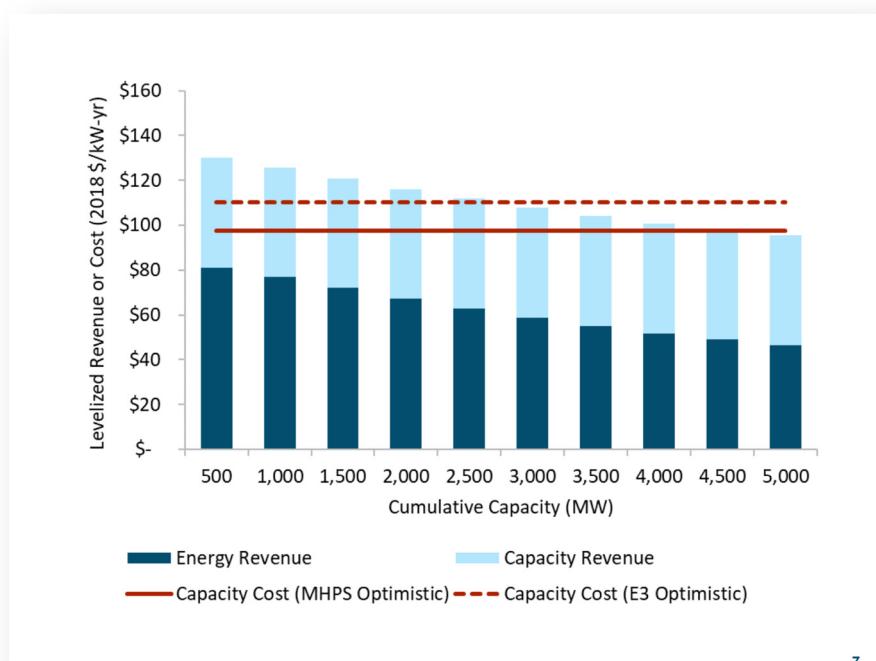


Figure 9-5: Levelized revenues and capacity costs as a function of cumulative installed capacity for hydrogen storage systems with CCGT installed in 2035 in California.



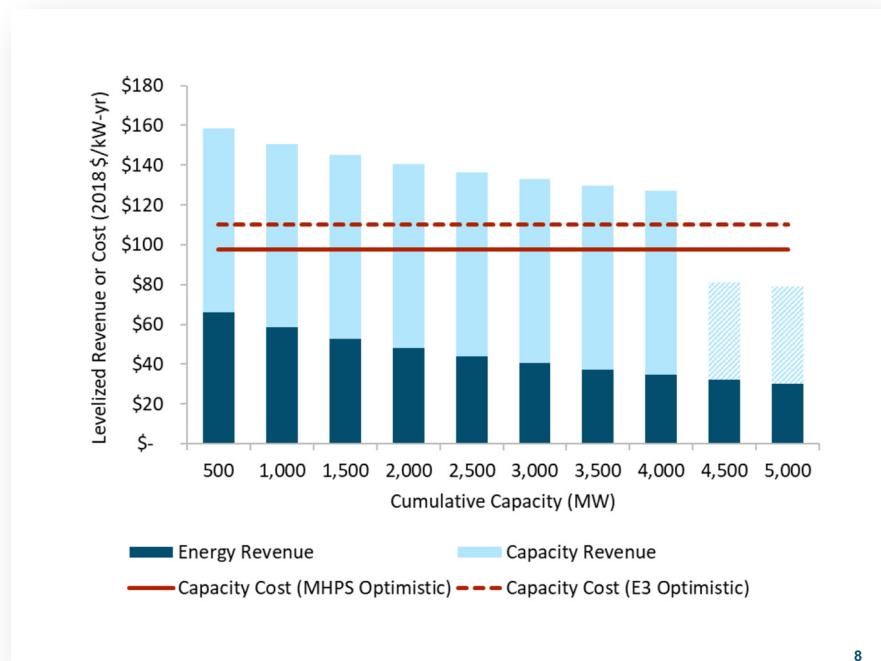
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Figure 9-6: Levelized revenues and capacity costs as a function of cumulative installed capacity for hydrogen storage systems with CT installed in 2035 in California.



7

Figure 9-7: Levelized revenues and capacity costs as a function of cumulative installed capacity for hydrogen storage systems with CT installed in 2035 in the Pacific Northwest.

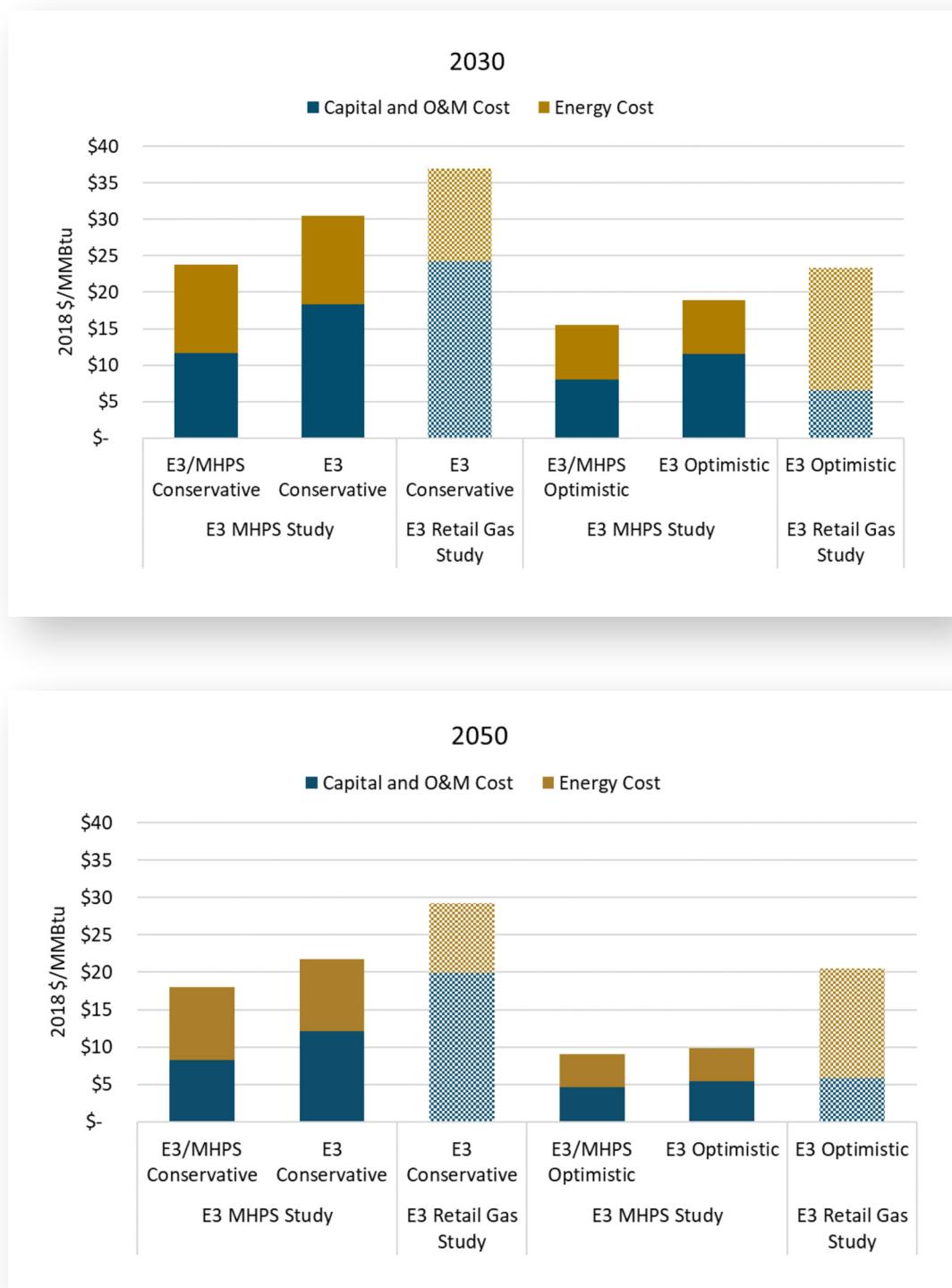


8

9.2 Comparison to CEC Retail Gas Study

The below figure compares the hydrogen cost estimates in the CEC-funded research study, "The Challenge of Retail Gas in California's Low-Carbon Future", relative to the cost estimates used in this study.

Figure 9-8: Comparison of the hydrogen cost assumptions in the E3 retail gas study and in this study for 2030 and 2050.



Notes:

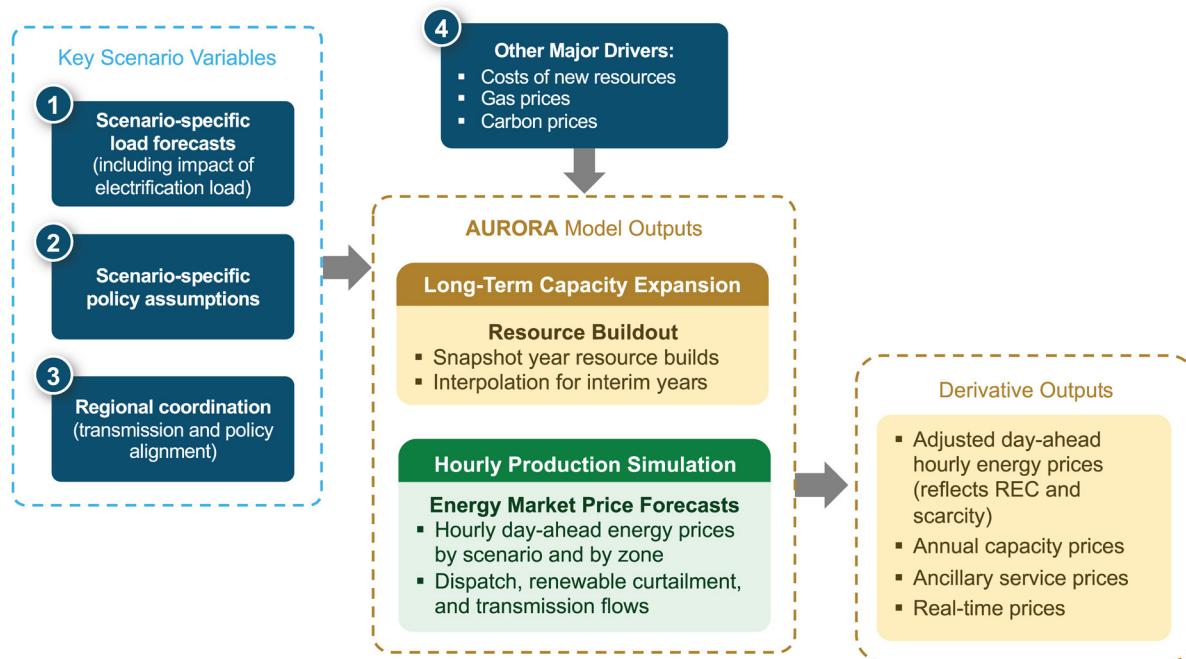
1. *E3/MHPS Conservative and E3/MHPS Optimistic cases assume MHPS electrolyzer cost estimates for 2020 and E3 conservative and optimistic learning curves, respectively. E3 Conservative and E3 Optimistic cases assume E3 electrolyzer cost estimates for 2020 and E3 conservative and optimistic learning curves, respectively. E3 electrolyzer cost and learning curve assumptions are based on the E3/UCI study for the CEC.*
2. *In addition to electrolyzer cost assumptions, differences in hydrogen cost between the two E3 studies originate from different electrolyzer types and energy resources assumed for hydrogen production.*
 - a. *The CEC retail gas study assumed alkaline electrolysis cells (AEC) in the 2030 Conservative case and solid oxide electrolysis cells (SOEC) in all other cases. The MHPS study assumed AEC in all cases.*
 - b. *The CEC retail gas study assumed off-grid California solar (25% average capacity factor) and off-grid Midwest wind (40% capacity factor) to power hydrogen production in the Conservative and Optimistic cases, respectively. The MHPS study assumed off-grid Utah solar (31% average capacity factor) in all cases. The different capacity factors as well as costs of these resources drive the differences in both capital and energy costs.*

9.3 E3's High Renewable Electricity Price Forecast in Aurora

E3 develops unique energy market price forecasts using a hybrid approach to combine optimal capacity market expansion under high renewable penetrations that represent robust and expansive views of the future electricity system. E3 performs a long-term power dispatch fundamentals analysis using Aurora⁵⁸ production simulation. This price projection approach produces relevant scenarios applicable for a highly complex and changing energy market like California. The resulting hourly energy price forecasts serve as the basis for additional sub-hourly and ancillary services derivative pricing. To reflect the West's evolving market, E3 models customized Aurora production simulation across several different scenarios based on forecast load, resource build-out and transmission assumptions. This process is illustrated in the diagram below.

⁵⁸ <http://epis.com/aurora/>

Figure 9-9: High-level visualization of E3's market price forecast modeling approach.



This study relied on the High RPS market forecast for the WECC, developed by E3 in Aurora, assuming attainment of the various renewable or clean energy targets that are being legislated in the West as of June 2019. These policy targets are shown in Table 9.1. Other key assumptions in the High RPS scenario are shown in Table 9.2.

Table 9-1: RPS policy targets used in E3's High RPS scenario in Aurora

High RPS Scenario		
State	Requirement	Effective RPS Target by 2050
AZ	50% by 2030, 60% by 2040, 70% by 2050	70%
CA	SB 100 (<i>carbon price at CARB floor</i>)	88%
CO	30% by 2020; 50% by 2040; 100% for PSCO by 2050	76%
ID	40% by 2040	40%
MT	15% by 2015 for IOU; 40% by 2040 for IOU	33%
NM	50% by 2030; 60% by 2040; 70% by 2050	70%
NV	50% by 2030; 60% by 2040; 70% by 2050	70%
OR	tiered RPS requirement (<i>carbon price assumed from 2025</i>)	39%
UT	40% by 2040; 50% by 2050	50%
WA	15% by 2020 (<i>carbon price assumed from 2025</i>)	12%
WY	40% by 2040	40%

Table 9-2: Key assumptions on load, resources, and costs used in E3's High RPS scenario in Aurora.

Key Assumptions	High RPS Scenario
California Loads	NREL load forecasts to reflect expected levels of electrification
Loads for Rest of WECC	NREL load forecasts to reflect expected levels of electrification
Technology Costs	E3 proforma modeling using publicly available costs data (NREL ATB, Lazard)
Resources (CA)	AURORA used for creating optimal portfolios to meet SB100 but with higher loads than Reference scenario; benchmarked to applicable RESOLVE cases
Resources (Rest of WECC)	AURORA used for creating optimal portfolios to meet most likely policies WECC-wide