ENERGY RESEARCH AND DEVELOPMENT DIVISION

FINAL PROJECT REPORT

Assessing the Role of Hydrogen in California's Decarbonizing Electric System

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PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency; renewable energy and advanced clean generation; energy-related environmental protection; transportation; and energy transmission and distribution.

In 2011, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation, and bring ideas from the lab to the marketplace. The EPIC Program is funded by California utility customers under the auspices of the California Public Utilities Commission. The CEC and the state's three largest investor-owned electric utilities — Pacific Gas & Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company — were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs to promote greater reliability, affordability, and safety for California electric ratepayers. EPIC investments advance these values by:

- Providing societal benefits.
- Reducing greenhouse gas emissions in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs, first with energy efficiency and demand response, next with renewable energy (distributed generation and utility-scale projects), and finally with a clean electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

Assessing the Role of Hydrogen in California's Decarbonizing Electric System is the final report for the Assessing the Role of Hydrogen in California's Decarbonizing Electric System project (EPC-23-004) conducted by RAND. The information from this project contributes to the CEC Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the Energy Research and Development Division at ERDD@energy.ca.gov.

ABSTRACT

This report is the final product of the Electric Program Investment Charge (EPIC) grant agreement (EPC-23-004), which included "an assessment of the potential role of hydrogen production from renewable electricity and end-use conversion technologies for electric sector applications in California's decarbonizing electric system." One of the primary objectives was to inform how future EPIC program investments in hydrogen can best coordinate with and complement other hydrogen development and deployment programs.

The research team conducted a techno-economic analysis to assess the cost and readiness of a range of technologies associated with a Senate Bill 100-compliant (zero greenhouse gas emissions) electricity grid in California. These technologies include hydrogen production, storage, and conversion, other types of energy storage, and solar and wind generation. The team then modeled the cost of serving load in a grid using hydrogen storage for two operational configurations: a daily cycle and a seasonal cycle. Results show that the seasonal cycle configuration reduces costs when compared with a grid without hydrogen. The findings were used to make recommendations related to hydrogen technology development and policy for the EPIC program.

Keywords: hydrogen, energy storage, seasonal storage, zero-carbon gas

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Senate Bill (SB) 100 (De León, Chapter 312, Statutes of 2018) requires that renewable energy and zero-carbon resources supply 100 percent of electric retail sales by 2045. This ambitious target entails phasing out fossil-fueled generation and replacing it with renewable and other zero-carbon electricity generation sources. While some new generation capacity will come in the form of SB 100-eligible firm, dispatchable power, the transition primarily requires the addition of substantial amounts of renewable generation resources, including solar photovoltaic (solar PV or PV) and wind power. These renewable resources provide intermittent power and therefore must be accompanied by energy storage systems to provide power when solar PV and wind do not. While storage capacity in California today is provided primarily by electrochemical batteries (especially lithium-ion [Li-ion] batteries), other storage technologies are available that may prove to be suitable alternatives or complements to battery storage. This project explores the potential value of adding SB 100-compliant hydrogen to California's electricity grid.

This project presents the results of a comprehensive analysis to determine the on-grid hydrogen generation technologies that will best help California achieve its electric sector policy mandates, especially SB 100, by 2045. The project had three main objectives:

- Evaluate emerging and nascent hydrogen technologies and competitor energy storage and conversion technologies that may be used in the electric sector.
- Estimate and compare the cost and performance of the electricity system in California with and without incorporating hydrogen under a variety of scenarios pertinent to achieving California's statutory climate and energy goals.
- Provide recommendations and guidelines to help coordinate future investments and inform research priorities.

The project entailed extensive literature review and compilation, selected expert interviews, and electricity-system modeling. These findings and recommendations will benefit ratepayers by more efficiently realizing the path to an affordable and reliable SB 100-compliant system.

Key Results

1. Hydrogen will be relatively advantaged for seasonal energy shift and resiliency within California's SB 100-compliant electricity system. This is because of hydrogen's unique physical characteristics and the disaggregation of the charge, storage, and discharge functions into separate devices, when compared with batteries. Hydrogen may remain uncompetitive on a levelized-cost-of-electricity basis but may still lower total SB 100 system costs by avoiding the procurement of solar PV capacity.
2. Given current investment trends, primary electricity generation in the coming SB 100-compliant California will overwhelmingly originate from solar PV. Electrolyzers with complementary diurnal ramping capability will be the most competitive in a solar

PV-dominated system, so the electrolyzer best suited for California's electric power system is the proton exchange membrane water electrolyzer. Due to the scale of utility power, the hydrogen (H_2)-fired gas turbine, underground H_2 storage, and H_2 pipeline are best suited for on-grid hydrogen-to-power. Successful SB 100-compliant hydrogen-to-power would require the maturation of all four technologies: proton exchange membrane water electrolyzer, H_2-fired gas turbines, underground H_2 storage, and H_2 pipelines.

3. Blending hydrogen into existing fossil gas infrastructure at low to moderate percentages accomplishes minimal decarbonization and does not aid in overcoming the unique technical challenges of high-hydrogen-percentage turbines. Projects that blend small percentages of hydrogen into fossil gas are therefore not effective applications of hydrogen in the state's power system and are not expected to meaningfully advance California's transition to zero-carbon resources.
4. SB 100 hydrogen-generated electric power is not firm power in the same way that today's fossil gas-generated electric power is. Hydrogen, like all other energy storage technologies, has to be produced (charged) weeks or months ahead of time, requiring a commitment to primary renewable energy resources. This may require a new regulatory framework that could be built upon the existing resource-adequacy framework.
5. The California Energy Commission's (CEC) Electric Program Investment Charge (EPIC) program should continue funding exploratory research but pause large capital investments into hydrogen technologies, given that critical demonstrations are already in progress, the set of best-fit hydrogen technologies has not yet demonstrated commercial readiness, and hydrogen is best suited to decarbonizing the final percentage of grid emissions. The Advanced Clean Energy Storage facility in Delta, Utah, is a comprehensive H_2 production, storage, and conversion project that will yield critical performance and cost data that should inform EPIC's future investment decisions.
6. Cost-minimizing capacity expansion modeling determined that future scenarios with hydrogen uptake for the electric power system would require far fewer hydrogen power plants than today's fossil gas-powered fleet, comprising ~10 percent or less of today's fossil gas fleet.
7. The potential benefits to ratepayers of more complex hydrogen infrastructure-sharing arrangements across other sectors — especially transportation, synthetic fuels, and chemicals refining — remain open questions.

Knowledge Transfer and Next Steps

The project team attended hydrogen conferences and summits, including the California Global Hydrogen Energy Transition Summit (June 2025), the Earthna Summit (April 2025), the Atlantic Council Global Energy Forum (June 2025) and the Aligning California's Hydrogen Research and Innovation Agenda Workshop (November 2024) for strategic discussions regarding the role of hydrogen. The team also held meetings with the CEC Energy Assessments Division and the California Public Utilities Commission, as well as discussed methods and findings with the project's technical advisory committee.

Findings and recommendations from this report suggest that the CEC should next consider researching select technologies, regulatory frameworks, and power purchase agreements needed to store and dispatch hydrogen across seasons. The CEC should also consider researching more sophisticated hydrogen infrastructure-sharing arrangements between sectors of the economy.

CHAPTER 1: Introduction

Introduction to Hydrogen for the Electric Sector

Senate Bill (SB) 100 (De León, Chapter 312, Statutes of 2018) requires that renewable energy and zero-carbon resources supply 100 percent of electric retail sales by 2045. A range of technologies will be required for California to meet this ambitious electric sector transition goal. Given the intermittent nature of many zero-carbon resources (for example, solar photovoltaic [solar PV, or PV], wind, hydropower), an SB 100-compliant grid will require substantial energy storage capacity. The majority of storage deployed in California today uses lithium-ion (Li-ion) battery (LIB) technology. The federal Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act (IRA) of 2022 renewed interest in hydrogen (H_2) technologies, which may importantly contribute to SB 100 mandates; but hydrogen's role(s) in the transition remains unclear. This problem has not been adequately addressed because both the decarbonization goals and the technologies required to achieve them are new and evolving and their fundamental physics and system dynamics are complex. This is particularly the case for energy storage technologies such as hydrogen, compressed air energy storage, pumped storage hydropower, emerging battery technologies, gravity storage, fly wheels, and others. As a result, the anticipated contributions of hydrogen technologies to SB 100 and related goals are not fully understood. Decarbonization of the electricity sector is well underway and the role of hydrogen must be determined so that hydrogen technologies can be efficiently integrated into the ongoing transition.

An analysis was conducted to determine the on-grid hydrogen generation technologies that will best help California achieve its SB 100 electric sector policy objectives for retail sales of electricity. The goals of the project included:

- Assessing the readiness of key hydrogen technologies, as well as their performance and cost characteristics.
- Determining where, within the electric power system, hydrogen is best suited.
- Determining the optimal contribution of hydrogen to the electric power system.
- Identifying which hydrogen applications to prioritize.
- Developing recommendations for prioritizing both Electric Program Investment Charge (EPIC) hydrogen-related investment and future research.

Outlooks on Hydrogen-to-Power

Renewably generated hydrogen for California's electric power system has received consider-able attention, but uncertainties remain. Although hydrogen may contribute to the electric sector, existing alternative technologies can fill similar roles on the electric grid, each with unique advantages and disadvantages arising from their unique physics, manufacturability, and costs. In 2022, Assembly Bill (AB) 209 authorized the Clean Hydrogen Program, which was established to demonstrate and scale up hydrogen derived from water, using eligible renewable energy resources (CEC, undated-c). Also in 2022, the California Legislature passed SB 1075, which calls for the California Air Resources Board (CARB), in consultation with the California Energy Commission (CEC) and California Public Utilities Commission (CPUC), to produce a comprehensive report on hydrogen. That report covers the development, deployment, and use of hydrogen across all sectors as a key part of achieving the state's ambitious climate, air quality, and energy mandates (California Legislative Information, 2022).

The 2022 CARB Scoping Plan is a statewide foundational report that outlines California's strategy to achieve carbon neutrality by 2045. The Scoping Plan builds upon existing efforts to reduce greenhouse gas emissions, air pollution, and reliance on fossil fuels and provides a comprehensive roadmap to integrating clean technologies, economic growth, and environmental progress while identifying key actions to ensure a sustainable transition. The Scoping Plan calls for 10 gigawatts (GW) of hydrogen combustion turbine capacity for the electric sector in 2045 (CARB, 2022), and CARB now suggests that 0.23 exajoules (EJ) of hydrogen (equivalent to 2 million metric tons) will be utilized in California per year in 2045, mostly for transportation (CARB, 2025). At 58 percent conversion efficiency (U.S. DOE, 2024b), producing 0.23 EJ of hydrogen would require 110 terawatt-hours (TWh) of primary electricity generation. In comparison, the CEC's demand forecasting group modeled the total annual electricity demand of the entire 2045 system, excluding hydrogen production, at about 350 TWh (CEC, 2023). Moreover, hydrogen used for grid power would result in losing more than half of the original clean primary electricity through conversion inefficiencies — that is, primary generation that could have decarbonized other end uses (Wakim and Spokas, 2024).

The Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES), which administers the California Hydrogen Hub, similarly envisions a large hydrogen presence in California, but with considerably more hydrogen allocated for power production (Galiteva et al., 2024). ARCHES proposes 4 million metric tons per year of hydrogen in 2045 for the electric power sector alone, primarily to help serve major population centers.

California's three major electric investor-owned utilities (IOUs) differ in their approaches to hydrogen-to-power. Southern California Edison (SCE), a single-fuel utility, suggests that 8 GW of clean firm capacity will be needed in 2045, in part because of the way it expects the annual load profile to change (SCE, 2019). In its view, clean firm generation could be served by clean hydrogen, geothermal, advanced nuclear power, or fossil gas offset by carbon capture and storage (CCS) (Stanford ENERGY, 2023; Southern California Edison, 2019). Fossil gas generation offset by CCS does not comply with SB 100, however (CEC, 2021b). Pacific Gas & Electric Company (PG&E) and San Diego Gas & Electric (SDG&E) are mixed-fuel utilities, delivering both electricity and fossil gas, and have promoted hydrogen blending (up to 20 percent) as a pathway to achieve SB 100 (PG&E, undated; SDG&E, undated). These companies also pursue other options. For example, SDG&E's Borrego Springs green hydrogen[1] project considers long-duration energy storage (Hydrogen Central, 2021; San Diego Gas & Electric Company, 2021).

[1] Green hydrogen refers to hydrogen produced with zero carbon emissions, most commonly through water electrolysis powered by renewable electricity.

A study published in 2021 also found that California would benefit from clean firm power capacity that included clean hydrogen, geothermal, or advanced nuclear (Long et al., 2021). The study ran three unique models that generated three quantitatively unique results with clean firm capacity varying between 10 and 20 percent of the total system capacity. In some scenarios, the authors of that study found that including clean firm generators reduced system costs even though they would operate only a small fraction of the time.

Nation-level modeling may be less meaningful for California-specific forecasting, but insights can still be gleaned. Forecasts by the National Academy of Sciences and the Electric Power Research Institute (EPRI) indicate slower hydrogen deployment timelines than those issued by CARB, CEC, and ARCHES. A National Academy of Sciences report expects the hydrogen deployment timeline to span decades and does not anticipate hydrogen utilization for electric power before 2035 (National Academies of Sciences, Engineering, and Medicine, 2024). One EPRI report notes potential utility in hydrogen utilization in Southern California, but primarily for transport and industry (Jereza, 2023). Additional EPRI analysis further discusses scenarios favorable for hydrogen that rely either on the mandate for zero-carbon electric power (versus net-zero) or scenarios in which both CCS and synfuel production either never reach technical maturity or remain disallowed (EPRI, 2025; see also Bistline and Young, 2022). In some scenarios, EPRI speculated that hydrogen power generation capacity could potentially remain on standby for more than a full year, thereby providing resiliency and resource adequacy but delivering a very small fraction of total electricity demand (EPRI, 2025). In another study, clean hydrogen-to-power through simple and combined cycles[2] was compared, primarily for peaking operation, but both were found to be uncompetitive (Schulthoff et al., 2021). Yet another study found hydrogen favorable for dispatchable power and long-duration energy storage in the western United States; but to compete on cost, the majority was derived from fossil gas with downstream CCS, which would not qualify under SB 100's current language (CEC; National Petroleum Council, 2024).

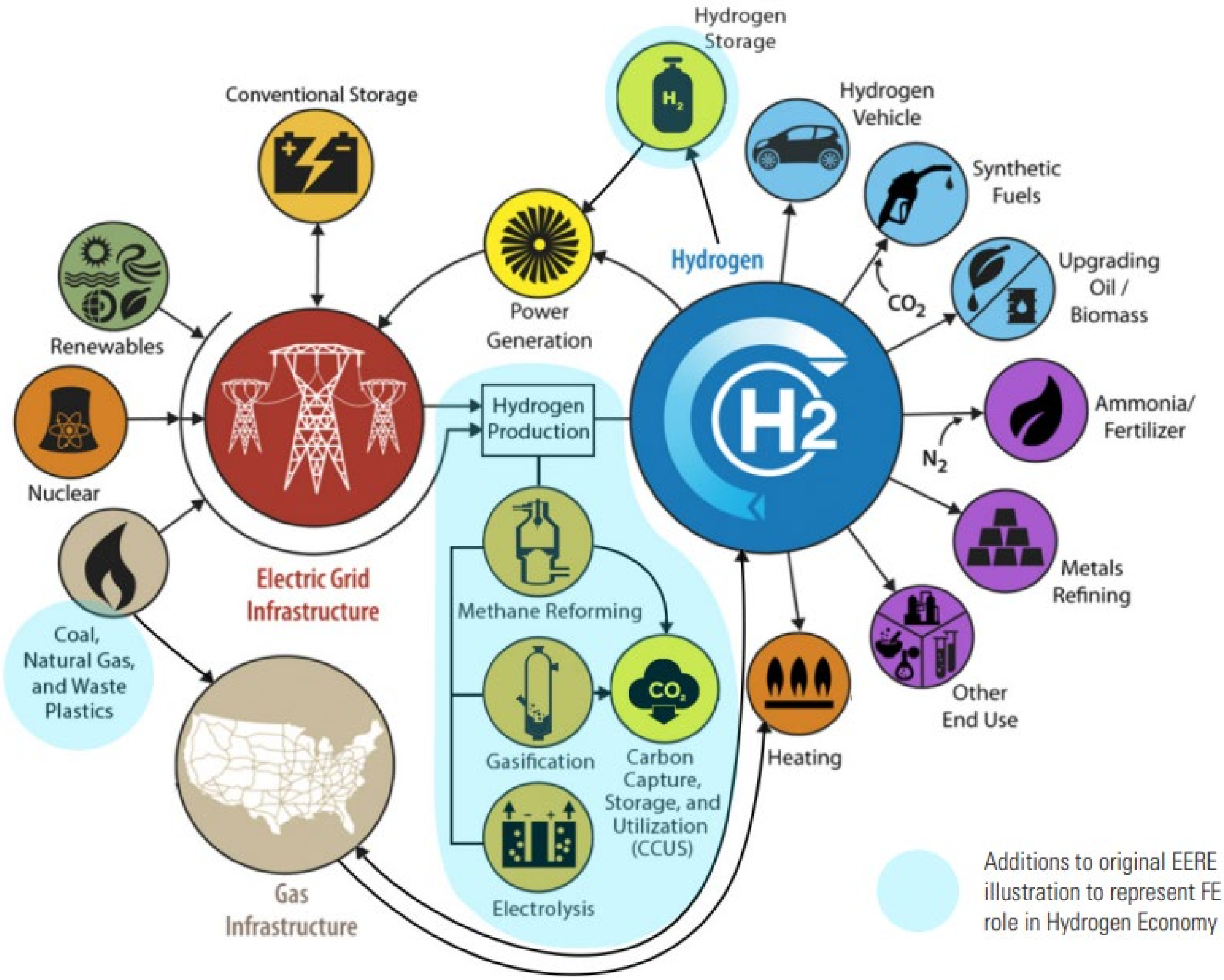
Some entities cast doubt upon hydrogen for the electric sector (DiChristopher, 2021; Odenweller and Ueckerdt, 2025) while others urgently favor it (International Renewable Energy Agency, 2018; Southern California Gas Company). Several other entities differ on the extent of hydrogen needed in net-zero scenarios (Gagnon; BloombergNEF, 2024; Tesla team, 2023; Krieger et al., 2024), with one stating that "hydrogen consumption between scenarios indicates its role is one of the least certain pieces of decarbonization," as its first key finding (Evolved Energy Research, 2023). To further highlight the ongoing uncertainty and need for additional research, the CPUC's 2023 Integrated Resource Plan retains substantial SB 100-ineligible generation in 2045, which underscores the importance of faster clean energy technology development and policies to accelerate deployments to meet SB 100 (CPUC, 2023b).

A final uncertainty associated with hydrogen's role in decarbonizing California's electricity system is that hydrogen has a wide range of potential applications across multiple sectors of the economy (Figure 1) (U.S. DOE Office of Fossil Energy, 2020; U.S. Energy Information

[2] A simple cycle uses a gas turbine to generate electricity, while a combined cycle captures exhaust heat from the gas turbine to power a secondary steam turbine that generates additional electricity.

Administration [EIA], 2024; Bockris, 1975), complicating decisions about coordination of investment and operation of hydrogen production, storage, and transportation.

Figure 1: Hydrogen's Potential Decarbonization Capability Across the U.S. Economy



Source: Hydrogen Strategy: Enabling a Low Carbon Economy. U.S. Department of Energy Office of Fossil Energy https://www.energy.gov/sites/prod/files/2020/07/f76/USDOE_FE_Hydrogen_Strategy_July2020.pdf

Given current uncertainties, clarifying hydrogen's role and purpose within the energy system will help guide California's clean energy and climate planning. To provide the CEC, the IOUs, and ratepayers with hydrogen investment recommendations, this project aims to determine the best-fit purpose of hydrogen for the electric power system. The EPIC program is not alone in this endeavor; entities across the world face decision-making challenges involving strategic investments in hydrogen technologies and continue to ask questions such as: How much hydrogen will be needed? When will it be produced? When will it be used? Which specific grid service(s) can hydrogen provide? Which grid service(s) would hydrogen provide most competitively?

CHAPTER 2: Project Approach

Overview

Considering the variation in legislation, planning documents, modeling, and studies on the role and value of incorporating hydrogen in California's energy grid, the research team took a systemwide approach in evaluating the cost of meeting California's projected electricity demand in 2045 with different combinations of SB 100-compliant energy generation and storage resources under different operating scenarios. A strength of this approach is that it allows comparison between the overall cost of different combinations of resources and scenarios where amounts of different resources vary in interdependent ways that cannot be easily projected independently.

To support this modeling, the team assessed and synthesized technology capabilities and costs, resource operation strategies, California's electricity needs, and key policies and programs for hydrogen technologies that pertain to the state's electric power system. Researchers considered a variety of zero-carbon generation and storage technologies, including solar, wind, geothermal, hydroelectric, batteries, and hydrogen. Nuclear power generation and biomethane were scoped out of this project by the CEC, drawing upon the SB 100 Joint Agency Report (CEC, 2021b). Because SB 100 applies to retail sales of electricity only, off-grid electricity generation was not considered.

Technology characteristics and costs were derived from literature, modeling and simulation, and subject matter expert input. The team elicited expert input from turbine and electrolyzer suppliers (including project partner, Ecolectro, Inc.), underground storage developers, and utilities engaged in incorporating hydrogen. The project's technical advisory committee members from the University of California at Irvine, the University of Rochester, Georgia Institute of Technology, the National Renewable Energy Laboratory (NREL), General Motors Company, PG&E, and RTX R&D advised on the research approach and verified various methodological aspects used. Details of the technology characteristics and costs, including justification for technologies included and excluded from the analysis, are provided in Appendix A.

Modeling Hydrogen in the System

The team began with an analysis of the operational characteristics, readiness, and costs of hydrogen technologies (in the context of grid services) to determine the most viable potential role of hydrogen in the electricity grid. That analysis, described in Chapter 3, points to energy reserves as one of hydrogen's most valuable contributions to the system. The team then developed scenarios with quantitative techno-economic models that clarify hydrogen's relative merits in greater detail. In each scenario, LIB was used as the baseline energy storage technology because it is mature and already deployed at utility scale, and hydrogen was allowed to substitute for LIB to varying degrees.

Physical models of key technologies and their operating strategies as well as a quantitative SB 100-compliant model for each scenario were developed. In each case, a system was simulated to reveal a key concept and tradeoff about hydrogen's relative strategic advantage(s). The team chose to emphasize SB 100 planning because hydrogen is not ready for commercial deployment in the near term. Instead, the modeling report informs investment and decision-making as if California were certain to achieve SB 100 by 2045.

Evaluating an optimal resource mix for California requires knowledge of the state's electricity demand. This report relied upon the 2045 load forecast developed by the CEC's 2024 *Integrated Energy Policy Report* (IEPR), which considers numerous effects in developing forecasts for communitywide planning purposes.

Future transmission and distribution constraints were considered but not explicitly resolved. The additional transmission infrastructure cost[3] from the potential addition of a small number of hydrogen power plants is small compared with today's transmission infrastructure and future generation buildout, so therefore would not appreciably alter the total cost of the SB 100 system (see Appendix A and California Independent System Operator, 2025).

Streamlined models for each scenario are presented, including end-to-end efficiency, a diurnal hydrogen cycle model, and a seasonal hydrogen cycle model. Additional complexity and detail were added to the seasonal cycle model to more accurately reflect finer details of California's system. The diurnal cycle and seasonal cycle models include an optimization routine layer to identify least-cost systems for the imperative of ratepayer benefit. Additional model details are provided in Appendix B.

Taken together, these models examine conditions under which the incorporation of hydrogen either does or does not convey a relative advantage. They therefore offer a framework for evaluating nascent hydrogen technologies and guiding future investment coordination.

[3] This grid planning consideration has been referred to as "transmission delay or deferral."

CHAPTER 3: Results

Characteristics of Hydrogen in the Context of Grid Services

Within the electric sector, "grid services" is the broad set of functions and supports that enable the grid to run reliably, affordably, safely, efficiently, and resiliently (CPUC, 2023a). This umbrella term includes both technologies and activities that contribute to supplying customer demand for electricity. Individual services can be technical and complex; a thorough list includes wholesale arbitrage, retail arbitrage, renewables integration, peaker plant replacement, black start, primary reserve, following reserve, secondary reserve, power quality, backup power, inertia, resource adequacy, voltage support, volt-ampere reactive support, seasonal storage, transmission upgrade deferral, distribution upgrade deferral, congestion relief, and demand response (Schmidt and Staffell, 2024; Schmidt et al., 2019; NREL, 2020; Liu et al., 2022; Denholm et al., 2019; Connected Communities). The California Independent System Operator (ISO) defines and operates "ancillary services" as frequency regulation, spinning reserve, nonspinning reserve, and voltage support, which, in addition to energy, are procured through both the real-time and day-ahead markets (ISO, 2024).

Renewable generation resources with inverter-coupled grid-forming batteries have been shown to be technologically capable of providing most grid services, including all the ISO-defined ancillary services (Jacobson et al., 2025; North American Electric Reliability Corporation, 2025; Loutan, 2020; ISO, 2017). While the CEC recently characterized grid-connected hydrogen technologies as useful for several grid services — including backup power, distributed generation, and microgrids (CEC, 2021a) — the team was unable to identify evidence that hydrogen technologies would outperform grid-forming inverter-coupled resources for ISO's ancillary services (Universal Interoperability for Grid-Forming Inverters Consortium, 2024). Accordingly, the project did not further investigate hydrogen for ancillary services in its analysis.

However, a few select grid services could still be appropriate for hydrogen, especially as hydrogen technologies mature and the system advances toward SB 100. In particular, the physical disaggregation of hydrogen production, storage, and conversion allows a hydrogen system to separately size and operate these functions, which provides some advantages over batteries, which must charge, store, and discharge via one device. Therefore, hydrogen for reserves (North American Electric Reliability Corporation, undated) or seasonal storage (U.S. DOE, 2024) would best complement batteries.

Hydrogen and competitor generators can be characterized by their operational capabilities. Generators have been differentiated as firm cyclers, flexible baseload, intermittent, or peakers (Sepulveda et al., 2018). Our analysis further differentiates between primary generators, which produce electricity from natural sources such as wind or solar, and secondary generators, which produce electricity from stored energy such as batteries or hydrogen systems.

The CPUC defines and utilizes two specific properties of generators: *firm* and *dispatchable*. Firm generators "provide power whenever needed and for as long as needed" while dispatchable generators "can be turned on or off at will and at any time" (CPUC, 2021). Secondary generators can only be firm or dispatchable when charged, so they are qualified as *contingent*. Batteries provide firm, dispatchable power contingent upon their states of charge. Hydrogen-fired gas turbines provide firm, dispatchable power contingent upon the amount of hydrogen previously generated and stored. Contingency implies forethought and possibly a regulatory framework to dispatch primary generators for the purpose of storing energy weeks or months ahead. Figure 2 characterizes key SB 100-compliant technologies.

Figure 2: SB 100 Technologies and Their Roles in the System

SB 100 2045 Technology / Source	Primary Energy Source	Primary Generator	Load	Energy Storage	Secondary Generator	Firm Generator	Dispatchable Generator
Sun, wind, biomass, geo heat	✓						
Geothermal generation		✓				Always	Always
Hydro generation		✓				Contingent	Contingent
Solar PV & wind generation		✓				Never	Contingent
Battery energy storage			✓	✓	✓	Contingent	Contingent
Electrolyzer			✓				
H_2 storage				✓			
H_2-fired turbine & H_2-fuel cell					✓	Contingent	Contingent

Source: RAND analysis

The ability to independently size and operate the charge, store, and discharge components allows the hydrogen energy storage paradigm to provide a very large energy-to-power ratio (E/P), denoted in megawatt-hours (MWh) per megawatt (MW), which dramatically reduces the scaling relationship between capital expenditure and storage volume. The ACES hydrogen facility in Delta, Utah, targets 11,000 tons of underground storage and 840 MW of hydrogen-fired gas turbine capacity for an E/P of 437 (ACES Delta, 2025). In contrast, today, the ISO-wide average for LIBs is 3.5 (ISO, 2024) and LIBs are unlikely to exceed single-digit E/P ratios. Green hydrogen is the only SB 100-compliant gas fuel, and therefore, the highest scalable SB 100-compliant E/P storage paradigm identified in this research project. Using the CPUC's language, hydrogen could be viewed as "more firm" than batteries because its high E/P ratio implies the ability to dispatch power for longer. Taken together, hydrogen's ability to decouple energy capacity and power capacity and reach very high energy-to-power ratios and to provision firm, dispatchable power, albeit with contingency, would likely exceed that of any LIB system. These features underlie hydrogen's competitive advantage and point toward its future role on the grid.

Specific Technologies Considered

This section provides an overview of the technologies considered in this analysis. A more detailed evaluation underlying the decision to emphasize these key hydrogen technologies is provided in Appendix A.

Given the substantial deployment of solar PV and LIB storage in California's electricity grid today, this modeling focused primarily on comparing a grid consisting of solar PV and LIB storage to a grid in which some LIB storage is replaced with hydrogen storage. Subsequent modeling incorporated additional SB 100-compliant generation resources, including geothermal, wind, and hydropower. A handful of competitor energy storage technologies such as pumped storage hydropower and compressed air energy storage were efficient and favorable in limited deployment but omitted from modeling because they depend upon unique geology and do not appear able to scale up to meet California's needs (see Appendix A and CPUC, 2024; ISO, 2022).

When considering specific hydrogen technologies to include, the team conducted stakeholder discussions and a literature review of numerous technologies, which led to the identification of several other key technologies: PEM-WE, hydrogen underground storage, hydrogen pipeline, and hydrogen-fired gas turbines. Fuel cells were not selected for detailed modeling because they are not being meaningfully pursued by suppliers for utility-scale power. Although the authors were unable to obtain a contemporary cost from a supplier, they infer from older cost reporting that fuel cells are considerably more expensive than batteries or gas turbines (see Appendix A for additional detail). Today's liquid alkaline electrolyzers feature slightly lower capital expenditure than PEM-WEs but cannot match PEM-WEs in efficiency, production rate, or, critically, the rapid ramping capability needed to pair with California's variable renewable generation (Hydrogen and Fuel Cell Technologies Office, 2022; Pointdexter, 2022; Carmo et al., 2013; Myers, 2021). The great majority of electrolyzers that are either under construction or planned with firm commitments are of the PEM-WE variety (Hubert and Arjona, 2024). Although hydrogen gas turbines are not commercially ready for purchase today, nearly carbon-free gas (primarily hydrogen) technology was reported to be successfully prototyped by General Electric and Siemens in 2015 (York et al., 2015; Marra, 2015). More details on the performance characteristics, technical readiness, and cost of hydrogen and other technologies are presented in Appendix A.

Hydrogen Blending

Our analysis did not consider running turbines with blends of hydrogen and fossil gas, primarily because such blends are not compliant with SB 100, which requires zero-carbon technologies.

Further examination also reveals that blending is unlikely to offer substantial benefits, even as an interim step toward full decarbonization. Because hydrogen has a much lower energy content per volume than fossil gas, blending with low to moderate volume percentages of hydrogen provides limited decarbonization. A 20 percent hydrogen blend achieves ~7 percent decarbonization, while a 50 percent hydrogen blend achieves ~21 percent decarbonization

(Goldmeer, 2019). Notably, existing fossil gas infrastructure cannot accept hydrogen blends above approximately 20 percent (Penchev et al., 2022).

Further, hydrogen blending is unlikely to inform the development and deployment of pure hydrogen fuel-gas turbine generators required by SB 100. High percentage and pure hydrogen turbines suitable for use on the grid are not ready for commercial deployment. In technical discussions, suppliers explained that upgrading a fossil gas turbine plant from a low-hydrogen blend (about 20 percent) to high or pure hydrogen is a major engineering endeavor requiring vast plant retrofitting. A key technical barrier is around 75 percent hydrogen, when new physical phenomena associated with burning hydrogen seriously challenge legacy designs. Suppliers further conveyed that above about 75 percent hydrogen, new turbine design becomes unavoidable. Other technical challenges with high-hydrogen blends remain: knowledge of >50 percent hydrogen blends is limited (Penchev, 2022); hydrogen/metal compatibility issues persist (Rogers, 1968; Cotterill, 1961); and H_2 blending causes problems for pipeline materials, compressors, valves, flanges, seals, flowmeters, line pack, and safety (Kass et al., 2023; Martin, 2024). Finally, because a fossil gas-hydrogen blend power plant does not comply with SB 100, any such plant constructed today would have to be either decommissioned or vastly rebuilt to comply with SB 100.

End-to-End Efficiency

To illustrate a key aspect of hydrogen's challenge for energy storage, the team modeled and analyzed the final energy yield after storage, conversion, and delivery of primary energy generation for two pathways: LIB and hydrogen. The efficiencies (energy losses) of all steps needed to bring SB 100-compliant primary energy from point of generation, via storage, to final customer were compiled from literature and subject matter expert interviews (see Appendix A), estimated, and summed; LIB and hydrogen pathways are compared in Figure 3. As energy proceeds from the point of generation to final delivery, inefficiency penalties accumulate. These cumulative losses are compiled in the "Energy" columns.

Figure 3: Final Energy Delivered for Li-Ion Grid Batteries and Hydrogen

Lithium-ion Grid Battery		
	Rated Power	
	Efficiency	Energy
Energy Generation		100%
Transmission Line Loss	95%	95%
Power Conditioning	95%	90%
Charge	92%	83%
Self-Discharge (2%/mo., 4 months)	2%	77%
Discharge	92%	71%
Power Conditioning	95%	67%
Transmission Line Loss	95%	64%
Final Energy		**64%**

PEM-WE + Pipeline + Underground + Gas Turbine		
	Rated Power	
	Efficiency	Energy
Energy Generation		100%
Transmission Line Loss	95%	95%
Power Conditioning	95%	90%
H2 Production, PEM-WE	58%	52%
H2 Transport, Pipeline	98%	51%
H2 Storage, Underground	87%	45%
H2 Transport, Pipeline	98%	44%
H2 Conversion (Gas Turbine, CC)	60%	26%
Power Conditioning	95%	25%
Transmission Line Loss	95%	24%
Final Energy		**24%**

Source: RAND analysis of efficiencies derived from literature and interviews (see Appendix A for details).

The end-to-end efficiency of the LIB pathway at rated power[4] is more than 2.5 times greater than the hydrogen pathway, even when including battery self-discharge over four months, representative of the loss during seasonal storage. From a given system of primary generators, delivering equal final energy to a customer would require 2.5 times more energy routed via hydrogen pathway than LIB, due to inefficiency. Accordingly, the hydrogen pathway must be at least 2.5 times cheaper than LIB to provide the customer with equal storage-mediated electricity at equal delivered cost. However, as discussed in Appendix A, the specific costs ($/kilowatt [kW]) of hydrogen technologies are higher than batteries today and are not likely to cheapen substantially in the near or moderate term. For example, the team estimates that the levelized cost of electricity (LCOE) of a hydrogen power plant in the near-to-moderate term (fewer than 10 years) in California would be about $700/MWh (see Appendix B), many times more expensive than that of today's generation (~$80-200/MWh for conventional gas-fired combined cycled plants [CEC, 2019]) and solar-plus-battery storage generation (~$70/MWh [International Energy Agency, 2024-b]). Accordingly, a lithium-ion grid battery would be more cost-effective than hydrogen at storing and delivering electricity on the margin, even for long-duration storage. Hydrogen is often proposed for long-duration energy storage, but the end-to-end efficiency calculation demonstrates that hydrogen's relative advantage is complicated by the performance of hydrogen infrastructure across the value chain. This further cements a framework for evaluating hydrogen and other energy storage technologies: LIB is the baseline technology to beat.

End-to-end efficiency demonstrates that with all else being equal, it is cheaper to incrementally deploy energy storage via lithium-ion batteries than hydrogen, even for long-duration storage, and will remain so for some time. Serving the marginal storage-intermediated megawatt-hour is not hydrogen's relative advantage.

To justify the high cost on the margin, hydrogen should aim to provide some other valuable grid service (for example, resource adequacy) and recover cost from that service. The cost advantage that LIB enjoys over hydrogen in an isolated, side-by-side comparison might be overcome if hydrogen performed some other role identified in a comprehensive systems analysis. The project's subsequent modeling considers the total system cost and performance of a complete SB 100-compliant grid (zero-carbon primary generation, energy storage, energy conversion) supporting the projected hour-by-hour electricity load in California in 2045. Subsequent analysis examines two operational concepts: a diurnal cycle, in which hydrogen is produced in one part of the day and converted to electricity later that same day (like most battery storage systems), and an annual cycle, where hydrogen is produced in one part of the year and converted to electricity later in the year.

Hydrogen Diurnal Cycle

A specific proposal for hydrogen-to-power is the diurnal production/consumption cycle. In this paradigm, a facility would generate hydrogen from PEM-WE during the day (powered by zero-carbon energy) and burn that hydrogen at night to meet load while solar PV does not generate. Lodi Energy Center, in conjunction with ARCHES and the U.S. DOE, is currently

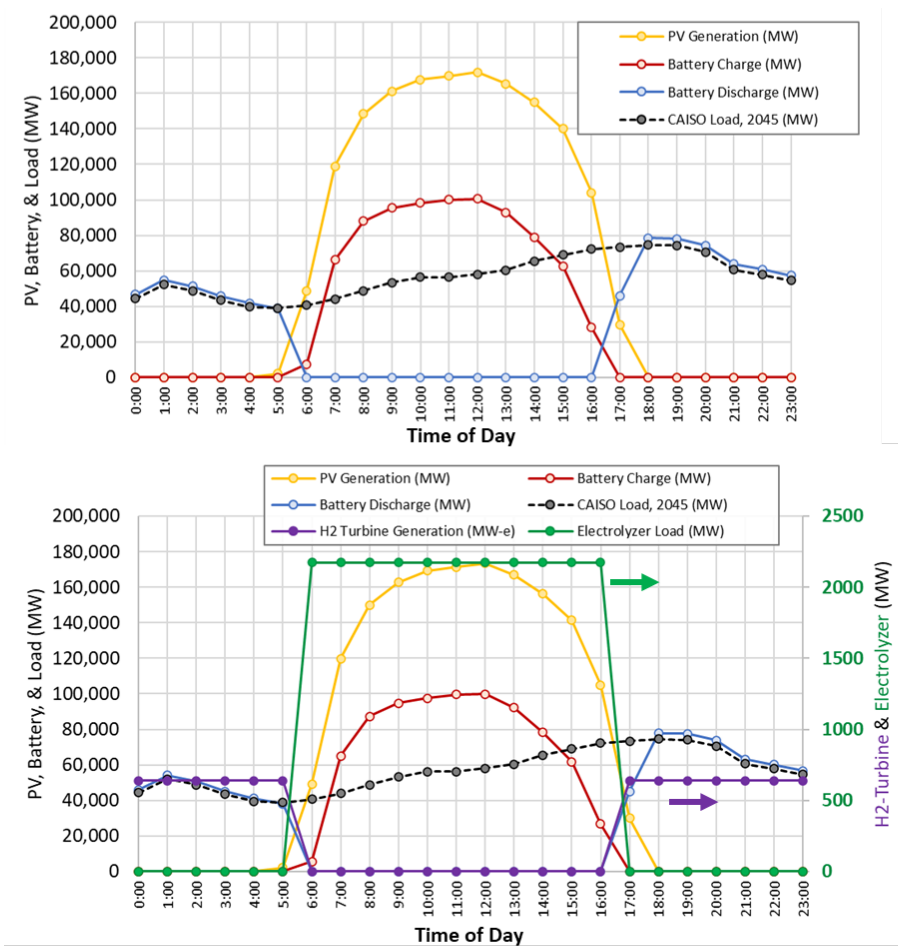
[4] Rated power is the maximum power an electrical device is designed to safely consume or generate under normal operating conditions.

upgrading its facility to perform this hydrogen diurnal cycle (City of Lodi, California, 2023; Howard, 2023). This concept was analyzed by constructing and comparing two model systems.

1. A system of solar PV and batteries.
2. A system of solar PV, batteries, electrolyzers, and one pure hydrogen-fired gas turbine combined cycle power plant (H2CCPP).

Fossil fuels and biomass were excluded because they are not SB 100 compliant. As previously noted, nuclear power was scoped out of this study. Comparing these two models determines whether hydrogen cycling diurnally would increase or decrease system cost. While a grid consisting only of PV, LIB batteries, and hydrogen is a simplification, it is a first step in understanding the difference in deploying hydrogen versus LIB batteries, the baseline energy storage technology. The operating strategy follows Lodi's paradigm: Hydrogen is produced during the day by a PEM electrolyzer, stored, then withdrawn at night to power the H2CCPP. Figure 4 shows the hourly dispatch profiles for each resource and the forecasted 2045 ISO load on a summer day. Model details are more fully described in Appendix C.

Figure 4: Hydrogen Diurnal Cycle Compared to PV and Batteries Only



Note: the green and purple arrows indicate H_2 turbines and electrolyzer results plotted on the right y-axis.

Source: RAND analysis

Resource costs including overnight capital costs, fixed operations and maintenance costs, and variable operations and maintenance costs were annuitized over the lifetimes of the assets. The total system annuitized cost (TSAC; see Appendix E) was minimized to identify least-cost resource mixes, which were then compared. The difference in resource capacity required to serve load with hydrogen versus without (ΔCapacity), the difference in that resource's annuitized cost (ΔCost), and the resource's overnight capital cost (OCC) are compiled in Table 1. Note that while uncertainties in total resource capacity requirements and costs with and without hydrogen may be substantial, the uncertainty in the differences in these values is much smaller.

Table 1: Diurnal Cycle System Capacity and Cost Difference

Resource	Δ Capacity	Δ Cost	OCC
PV Nameplate Power	+1,899 MW	+322 M$/y	1,502 $/kW
Battery Nameplate Energy	-9,018 MWh	-704 M$/y	436 $/kWh
H2CCPP Net Plant Power	+622 MW	+105 M$/y	1,429 $/kW
PEM-WE Nameplate Power	+2,175 MW	+966 M$/y	2,000 $/kW
H_2 Generation Required	+416 tons		
H_2 Pipeline	+100 miles	+16 M$/y	1.7 M$/mile
H_2 Underground Storage	+693 tons	+1 M$/y	17 $/kg
Total **Δ percent of System Cost**		**+405 M$/y** **+0.32 percent**	

kWh = kilowatt-hour
Source: RAND analysis

Adding one H2CCPP also requires significant additional PV capacity to power the necessary electrolyzers. In exchange, substantially less battery capacity is required to meet load. However, on net, at today's technology costs, the addition of the first H2CCPP operating the single-day hydrogen cycle would increase the TSAC by ~$400 million per year and would therefore increase the overall cost of serving load, versus grid batteries. Furthermore, a sensitivity analysis determined that breakeven would only likely be achieved when the costs of PV and electrolyzers are assumed to decrease by 50 percent while battery costs remain constant, neither of which is expected based on current cost trajectories (see Appendix A).

This model demonstrates that even within a system optimized for purpose storing utility-scale quantities of energy, hydrogen is relatively disadvantaged versus batteries for storing energy for short storage durations.

The cost increase for adding the first diurnal H2CCPP is approximately 0.3 percent of the total system cost. Although more expensive, hydrogen uniquely provides contingently firm and dispatchable capacity, diversified energy reserves, and supply chain diversification. Thus, this additional expense can be interpreted as the premium required to underwrite the system with the operational and supply chain characteristics of hydrogen that are not readily captured by this study's scope and analysis.

This model omits wind, hydroelectric, and geothermal generators for simplicity because they are a relatively small fraction of generation today and may not be viewed as sufficiently reliable for planning a daily-operated cycle (NREL, 2014). Furthermore, the team assumed hydrogen was injected into and withdrawn from an underground storage facility. That's in contrast to Lodi Energy Center, which plans to store hydrogen in numerous cylinders, which may increase storage costs by approximately a factor of 50 (Howard, 2023; Hydrogen Tools; Abdin et al., 2022).

Hydrogen Seasonal Cycle

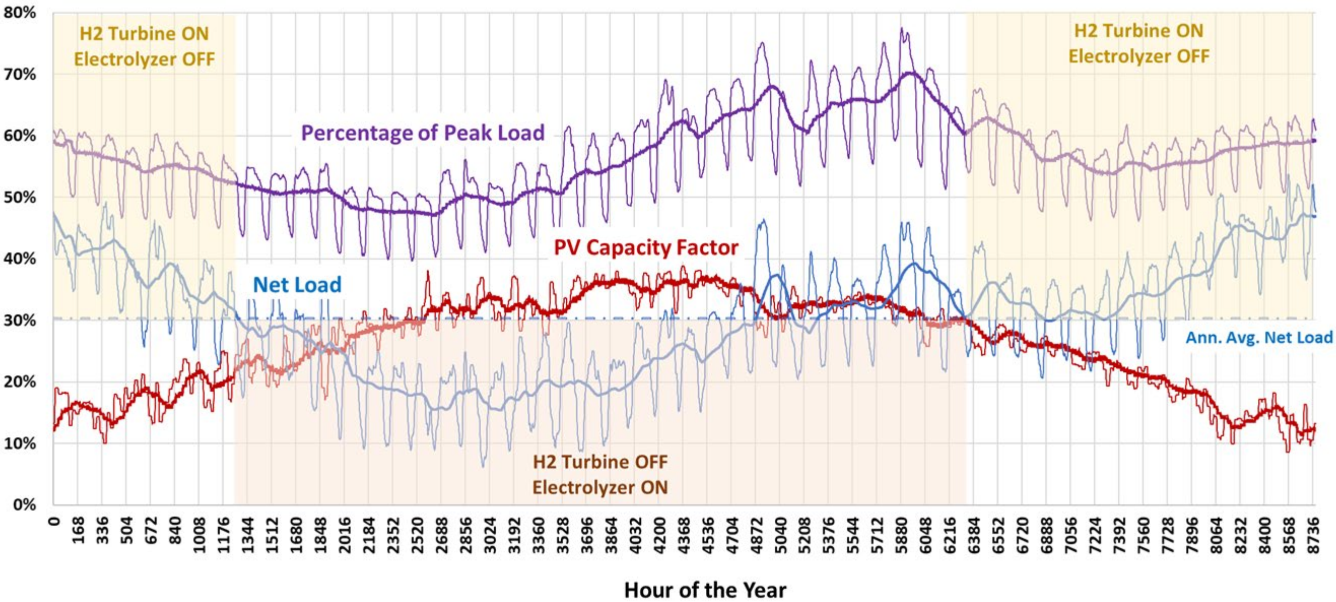
The efficiency model examined long-storage duration without scale while the diurnal model examined large-scale storage without long-storage duration. An alternative operational approach to using hydrogen for the grid is to utilize it for seasonal energy shifts — in other words, hydrogen for large-scale energy storage *and* for long-duration storage. Using an in-house developed capacity expansion model streamlined for specific questions regarding hydrogen for seasonal energy storage, resource mixes were modeled, simulated, and optimized to identify least-cost systems. These were determined from syntheses of performance models of key technologies, resource dispatch simulations with a 1-hour resolution over a complete year, and a differential evolution optimization routine to minimize total system cost while ensuring that supply met demand at every hour of the year.[5]

To execute a hydrogen seasonal cycle economically, resources must be strategically dispatched. Because there are no gas turbine power plants performing seasonal energy shift today, the team developed the concept of *net load* as the basis for the design of a seasonal dispatch strategy to use in simulations. Net load at a given time is the system demand (as a share of annual peak demand) minus the PV generation (expressed as a share of installed PV capacity). Net load is large when demand (load) is high and PV capacity factor is low — typically the time of year when the system requires the greatest support from seasonal storage.

The proposed dispatch strategy switches between producing and storing hydrogen when net load is low (below the annual average net load) and converting hydrogen to energy when net load is high (above the annual average net load). Further, electrolyzers operate in an opportunistic fashion, powered by excess PV generation sequentially after batteries are fully charged. Hydrogen gas turbines are utilized during the converting portion of the year, turning down to 50 percent of rated power during the producing and storing portion of the year when PV is generating in excess. The hydrogen seasonal cycle strategy with net load is shown in Figure 5.

[5] In future work, this approach could be used to estimate the cost of demand response.

Figure 5: Hydrogen Seasonal Operating Strategy



Note: Includes daily- and weekly-averaged data for the percentage of annual peak load, PV capacity factor, a percentage, and their difference, the "Net Load."

Source: RAND analysis

The proposed strategy would likely require a full-year time commitment for planning, which would comport with the longer-term contractual commitments of power purchase agreements (ENGIE Impact, 2024) (cf. merchant power, see Energy, Utilities, and Communications Committee) and the biannual periodicity of California's load forecast exercise (California Public Law, 2019). In reality, hydrogen resource operators would have to guess seasonal on-and-off dispatch timing equipped only with historical data and weather forecasts, so cost recovery may have to be guaranteed by a to-be-determined policy mechanism. The hydrogen power plant could plausibly participate in the day-ahead market on top of a power purchase agreement to further optimize performance and increase revenue, but further examination of this possibility goes beyond the scope of this report.

Like for the diurnal cycle, the relative advantage or disadvantage of hydrogen is illustrated by modeling and comparing two resource mixes:

1. A system of solar PV and batteries.
2. A system of solar PV, batteries, electrolyzers, and one pure H_2-fired H2CCPP.

However, for the seasonal cycle, systems are simulated and optimized over a full year of serving load. As noted above, alternative candidate SB 100-compliant long-term storage technologies were excluded because they do not appear able to scale up to meet California's needs. The differences in capacity and in TSAC of each resource between the two scenarios are presented in Table 2. The OCC that were used in the diurnal cycle were also used in the seasonal cycle.

Table 2: Seasonal Cycle System Capacity and Cost Difference

System Component	Δ Capacity	Δ Cost
PV Nameplate Power	-181,563 MW	-30,746 M$/y
Battery Nameplate Energy	+20,985 MWh	+1,637 M$/y
H2CCPP Net Plant Power	+640 MW	+105 M$/y
PEM-WE Nameplate Power	+4,737 MW	+2,105 M$/y
H_2 Generation Required	+148,288 t	
H_2 Pipeline	100 miles	+16 M$/y
H_2 Underground Storage	+247,040 t	+364 M$/y
Total		**-26,519 M$/y**
Δ percent of System Cost		**-16.5 percent**

Source: RAND analysis.

This model resulted in a TSAC reduction of ~17 percent per year for adding the first hydrogen power plant to the system. This is because of the massive reduction in the PV capacity (and therefore the cost) required to meet electricity demand. In this model, PV capacity was reduced by 182 GW — approximately 30 percent of the PV capacity required to meet load with PV and batteries alone. Adding the first hydrogen power plant therefore also reduced PV primary energy generation from approximately 1,300 TWh (without H2CCPP) to 900 TWh (with H2CCPP).

This model demonstrates that hydrogen's comparative advantage under SB 100 is its ability to store and shift utility-scale quantities of energy across seasons. Hydrogen is best suited for energy storage at both large-scale and long duration energy storage, within a system designed for purpose.

The underlying reason why PV capacity can be dramatically reduced is because of a key system planning constraint: planning to serve load without shortfall implies that the system must be sized to meet demand in the most challenging hour of the year (California ISO, 2023; ISO, 2025). As a result, the marginal solar panel and battery added to serve that worst hour of the worst day, operates at an extremely low utilization rate. If the LCOE of the marginal solar panel and battery were calculated separately, it would far exceed the LCOE of hydrogen-generated power.[6] Fundamentally, this is hydrogen's core advantage: In a system targeting very high shares of zero-carbon generation (e.g., SB 100), a small amount of hydrogen capacity can displace other, high-cost marginal capacity primary generators and reduce overall system costs.

[6] For example., a solar panel utilized one day per year at 1,500 $/kW and 7 percent CRF would generate an LCOE of 20 $/kWh

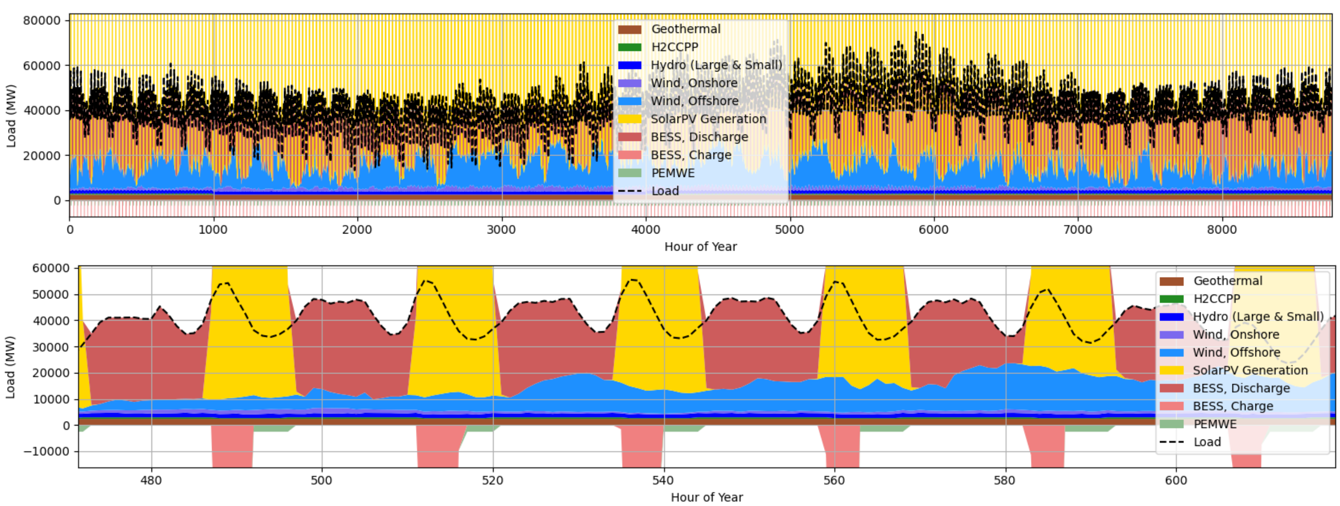
Hydrogen Seasonal Cycle Synergies

Building upon the key relative advantage of hydrogen, the team carried out more detailed seasonal simulations to demonstrate hydrogen's synergies and advantages in the presence of other speculative technologies and forecasts for cost reductions. Onshore wind, large and small hydro, and geothermal were modeled with today's power capacities and costs, which assumed that existing SB 100-compliant resources will be maintained until 2045 and not decommissioned.

Offshore wind, which California is aggressively targeting, was also considered. Offshore wind exhibits high spatiotemporal variability, making it impossible to develop a single supply projection. Scenarios incorporating offshore wind were simulated by averaging the modeled power output distributed across six key locations in California for each of 22 independent years of wind-speed data. Appendix D provides additional details. Because supply from offshore wind varies from year-to-year, modeling results are shown for both the best and worst wind years.

With these additional resources included, the team performed similar simulations and least-cost optimizations to determine the total system annuitized cost differences (%ΔTSAC) achievable for varying contributions of key resources. The simulation output can be visualized as a stacked plot with the hour-by-hour power level of each resource category on the system. An example of a full-year, 1-hour-resolution, least-cost system simulation is shown in Figure 6.

Figure 6: Example Simulation of an Optimized System



Notes: Top panel shows all 8,760 hours of the year and bottom panel shows expanded detail from left portion of top panel. Vertical axis of each plot truncates the daily peaks of the solar PV generation curve to better display details of the other curves.

Source: RAND analysis

The team tabulated least-cost system results for the best wind year (largest achievable cost reduction) and the worst wind year (smallest achievable cost reduction or cost increase) in Table 3. Each column (scenario) corresponds to a set of input parameters, including the H2CCPP capacity, offshore wind capacity, and geothermal capacity. Onshore wind and hydropower capacity were constant for all scenarios and are not shown. For all columns with

H2CCPP, the electrolyzer capacity (not shown) was minimized so that only sufficient hydrogen to fuel the power plant was generated. The capacities of PV, batteries, and PEM-WE were variables determined by the optimization solver. Capacities of H2CCPP, offshore wind, geothermal power, and specific costs of all technologies were parameters outside of the optimization routine (exogeneous variables) and were selected for scenario and sensitivity analysis based on findings from Appendix A. Table 3 presents results under the assumption of no cost declines over the next 20 years. Forecasted cost reductions are addressed in Table 4.

Table 3: Scenarios for the CA 2045 System

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
%ΔTSAC, best year	0	0%	+3%	-10%	-16%	-11%	-14%	-15%	-15%	-15%	-15%	-19%	-20%	-5%	-5%
%ΔTSAC, worst year	0	0%	+3%	0%	+1%	0%	0%	+1%	0%	-4%	-5%	-5%	-4%	0%	0%
H2CCPP (MW)	0	645	3,225	0	0	645	645	1,290	3,225	0	645	3,225	0	0	645
Offshore Wind (GW)	0	0	0	10.9	21.8	10.9	21.8	21.8	21.8	10.9	10.9	21.8	21.8	3.6	3.6
Geothermal (MW)	2,744	2,744	2,744	2,744	2,744	2,744	2,744	2,744	2,744	5,488	5,488	5,488	5,488	2,744	2,744

Source: RAND analysis

If no cost reductions are realized by 2045, incorporating hydrogen into the grid could either insignificantly change or marginally increase total system cost versus a baseline without hydrogen or offshore wind (compare columns 2 and 3, versus column 1); the model estimates no cost difference for adding 645 MW of H2CCPP (one power plant) and a 3 percent increase for adding 3,225 MW. Because hydrogen does not by itself significantly reduce system cost, and may slightly increase it, the H2CCPP capacity in SB 100 will likely be much less than today's fossil gas-fueled fleet of more than 86,000 MW (CEC Electric Generation Capacity and Energy, 2025).

This result contrasted markedly from the results in Table 2 that considered only PV, batteries, and hydrogen. In Table 2, geothermal, hydro, and onshore wind were excluded for simplicity purposes to illustrate hydrogen's relative advantage as a storer of energy. In Table 3, geothermal, hydro, and onshore wind were included and contributed SB 100-compliant generation when solar PV cannot, reducing the need for energy storage altogether (hydrogen or LIB). Moreover, while removing excess PV capacity was identified as a key comparative advantage of hydrogen, other energy resources like geothermal, hydro, and wind also offer this advantage. SB 100-compliant primary generators that generate at night claimed some of the cost benefits that hydrogen would otherwise provide. Note that scenarios with substantially increased geothermal generation (columns 10 through 13) would be similar to scenarios with online nuclear generation since both deliver firm, baseload power.

If offshore wind is added, it could substantially reduce system cost, with best-year case cost differences reaching –20 percent. But this cost savings comes with a major caveat: Large interannual variations in offshore wind speed lead to large variations in energy generated, which would complicate integrated resource planning and system reliability. This variation is reflected in the large difference of %ΔTSAC between best and worst wind years. The difference scales with offshore wind capacity, so much so that offshore wind could decrease system cost in a good wind year but increase it in a bad wind year (see columns 5 and 8). Pairing hydrogen with offshore wind would employ hydrogen's other advantage discussed in Chapter 2: the very large energy-to-power ratio, which could be leveraged to smooth interannual variance at low storage cost. This project did not address multidecade system dynamics, but the results illustrated in Table 3 suggest that hydrogen could play an important role across extended years of system operation. Separately, if additional geothermal or similar baseload were to be brought online, system cost would likely be reduced further (compare columns 4 and 10).

Hydro and onshore wind were included in Table 3 results but must be appropriately understood as highly variable. For example, despite constant installed capacity, hydroelectric generation in California varied by more than a factor of two over the past five years, driven by fluctuations in precipitation and drought conditions (CEC, undated-d). California also experienced a major drought that affected the power sector between 2012 and 2016 (Kern et al., 2020). It remains unknown how resources with constrained reliability will be valued and integrated into the preferred system plan in the future when the requirements of SB 100 are in place. If resources with unsatisfactory reliability are discounted, hydrogen may again be favorably employed to strengthen the system.

The difference in results between Tables 2 and 3 — that adding hydrogen to a pure solar-battery grid offers substantial cost savings that are reduced when considering a more diverse grid with other generation sources — reflects the complex and subtle interplay that different types and amounts of generation and storage resources have on total system cost. Such insights are only possible when modeling the total system and would be missed if the focus is solely on component costs (for example, levelized cost of hydrogen or LCOE).

The team's techno-economic analysis identified potential future cost reductions for various technologies (see Appendix A). When incorporating these anticipated cost reductions in this model, hydrogen still does not appreciably affect the total system cost (Table 4). Moreover, the benefit of offshore wind will be significantly reduced if solar PV and batteries realize optimistic, forecasted cost reductions. And if offshore wind were to be disfavored, hydrogen would become less necessary for smoothing out accompanying interannual variations.

Table 4: Resource Mixes for Scenarios with Optimistic Cost Reductions

	16	17	18	19	20	21	22
%ΔTSAC, best year	0	-41%	-41%	-40%	-41%	-43%	-44%
%ΔTSAC, worst year	0	-41%	-41%	-40%	-40%	-40%	-40%
H2CCPP (MW)	0	0	645	1,290	1,290	1,290	3,225
Offshore Wind (GW)	0	0	0	0	0	10,900	21,800
Geothermal (MW)	2,744	2,744	2,744	2,744	2,744	2,744	5,488
PV Cost ($/kW)	1,502	393	393	393	393	393	393
BESS Cost ($/kWh)	432	262	262	262	262	262	262
PEM-WE Cost ($/kW)	2,000	2,000	2,000	2,000	1,500	1,500	1,500

Source: RAND analysis

Impact of Key Policies on Model Results

Recent policies of greatest impact on hydrogen technologies for the electric sector are compiled in Table 5.

Table 5: Recent Policies Pertinent to Hydrogen for the Electric Sector

2018	Low Carbon Fuel Standard
2018	SB 100 (100% of retail electric sales will be zero-carbon)
2021	Infrastructure Investment and Jobs Act (IIJA) (funding for various infrastructure projects, including H2)
2021	Senate Bill 423 Firm Zero-Carbon Resources (requires CEC, CPUC to submit to the Legislature an assessment of firm zero-carbon resources that support a clean, reliable, and resilient electrical grid)
2022	Inflation Reduction Act (IRA) (numerous components, especially 45 V H2 production tax credit)
2022	SB 1075 (Law requiring a comprehensive hydrogen study)
2022	AB 1279 (statewide net-zero by 2045, net negative thereafter)
2022	AB 209 (established a Clean Hydrogen Program to provide incentives for in-state projects that demonstrate or scale-up the production, processing, delivery, storage, or end-use of hydrogen.)
2023	U.S. EPA's Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources
2024	Chevron deference overturned (shifts power from agencies such as EPA to judiciary)
2025	Executive Orders

Source: RAND analysis

Policies from 2024 and earlier largely favor hydrogen. The impacts of most are indirect and hence difficult to quantify. For example, SB 100 is the impetus for much of the investment into renewables and storage, which has undoubtedly increased investment in research, development, and deployment, but estimating the cost impact is difficult without a counterfactual case (without SB 100).

One policy the team was able to quantify was the clean hydrogen production tax credit in the federal IRA. Applying the production tax credit showed that it would have a small impact on total system costs when hydrogen is used for seasonal storage. In the high-hydrogen scenarios modeled here, hydrogen production reaches about 600,000 tons per year. At a credit of $3 per kilogram (as credited by 26 U.S. Code Section 45 V), this corresponds to about $1.8 billion per year in subsidy payments to California's system, or about 1.3–1.8 percent of total SB 100 electric system costs. This subsidy would certainly directly benefit individual hydrogen producers but would not significantly alter the balance of least-cost resources California should deploy for its electric power system.

Policy guidance since 2025 stems primarily from a series of energy-related executive orders and other rulings. These include withdrawing from the Paris Agreement under the United Nations Framework Convention on Climate Change; loss of funding for federally funded hydrogen grants and programs (including California's hydrogen hub, ARCHES); loosening eligibility rules for hydrogen production tax credits; increased tariffs on imported equipment, including hydrogen electrolyzers and turbines; pulling back support for offshore wind; and significant support for increased domestic oil, gas, and coal production.

The impacts are generally indirect and shrouded by the nature of originating via executive order instead of legal code, making it difficult to precisely quantify their effects. In general, they disfavor hydrogen, either by decreasing demand, increasing cost, or both. GE Vernova has stated that tariffs would increase costs, though the brunt of this impact will be on wind turbines, and notes that the power turbine segment remains strong (Rogers, 2025). Tariffs would increase battery costs, but also by an amount that cannot be quantified accurately today. The IRA 45 V H_2 production tax credits were expanded to include "nongreen" production. SB 100 requires green H_2, so stimulating other resources is largely irrelevant unless it diverts investment from green hydrogen production. Federal support for green H_2 R&D has been significantly cut. Overall, these actions could delay the deployment of hydrogen technologies and slow cost reductions, misaligning with California's objectives and timelines.

The moratorium on offshore wind strands California's anticipated >20 GW planned capacity addition. Regulations for energy infrastructure permitting and construction are to be loosened, which may decrease hydrogen technology costs as well as decrease other technology deployment costs. Because these policies have not been officially adopted, the relative gain or loss for each technology cannot be precisely determined.

Environmental Impacts of Hydrogen on the Grid

The potential environmental impacts of the integrated set of hydrogen technologies include global warming, air quality, and water consumption. Analysis and elaboration are provided in Appendix D. Modeling results pointed toward adding only a limited number of hydrogen power plants to the system, which would consume a limited amount of hydrogen, especially as compared with fossil gas power plant operations in California today (EIA, 2023a).[7]

Greenhouse Gas Emissions

Hydrogen combustion does not generate carbon dioxide (CO_2) emissions. With the U.S. Environmental Protection Agency (U.S. EPA)-regulated nitrogen oxide (NOx) controls, hydrogen can be included in an SB 100-compliant grid with negligible impact on greenhouse gas emissions. Still, hydrogen is a greenhouse gas, and there is uncertainty about the emissions potential from leaks occurring in the production, transportation, and storage of hydrogen. Some insight can be gained from California's current fossil gas releases (fugitive plus venting), which represent a small percentage of gas throughput, or about 0.15 percent. The amount of leaked hydrogen would likely be substantially less than this due to substantial downsizing of gas needs and associated infrastructure for hydrogen seasonal energy storage versus today's fossil gas fleet.

Air Quality

This research found that pure hydrogen power plants would generate zero or negligible sulfur oxides and carbon monoxide. Hydrogen turbines produce NOx at greater rates than fossil gas turbines, but mitigation technologies that keep NOx emissions within regulatory limits are mature and not anticipated to increase power plant costs by more than a few percent (National Energy Technology Laboratory, 2022; Office of Air and Radiation, 2023; Sorrels, 2019).

Water Consumption

Hydrogen production consumes between 20 and 30 liters of water per kg of hydrogen produced. For the amounts of hydrogen consumed in these modeling scenarios, this amounts to 0.03 percent of California's annual water consumption. This is less than current water consumption (evaporation) from thermal electricity generation (0.04 percent), indicating that the addition of hydrogen production accompanied by the elimination of thermal generation would result in net water savings for California. Water will be neither a technological nor an economic barrier to hydrogen utilization for the state's electric power system, in sound agreement with other researchers (Rincon et al., 2025; Krieger et al., 2024).

Taken together, the findings indicate that hydrogen would have negligible additional environmental impacts compared with other SB 100-compliant scenarios. Because the analysis was conducted at the state level, it may not capture site-specific effects, including potential water constraints in locations with limited water availability. Future research should evaluate local water sourcing and infrastructure requirements.

[7] In 2023, California's electric sector consumed 129 TWh of natural gas whereas 645 MW of seasonally operated hydrogen gas turbine capacity would consume ~4 TWh per year.

Benefits to Ratepayers and Disadvantaged Communities

Benefits to Ratepayers

The EPIC Impact Analysis Framework (Beck, 2024) defines five ratepayer benefits: improved safety, increased reliability, increased affordability, improved environmental sustainability, and improved equity.

The principal ratepayer benefit of this analysis is an increase in the affordability of electricity service (see Appendix D). In determining the operational conditions under which incorporating hydrogen into California's electricity grid helps the system to meet demand at lower cost than a system without hydrogen, this analysis constrains the feasible options for how to incorporate hydrogen into the grid. This, in turn, helps ensure that the CEC, associated agencies, and industry design an SB 100-compliant grid that minimizes the cost of supplying electricity to ratepayers. This analysis found that, in conjunction with other technologies, deploying hydrogen in a seasonal storage role could have lower cost than an equivalent system with no hydrogen — and so merits further consideration. Conversely, the team found that deploying hydrogen in a daily storage role would have a higher cost than an equivalent system with no hydrogen and therefore should not be considered further.

This analysis and its recommendations may also increase the reliability of electrical service to ratepayers. An additional benefit of configuring hydrogen for seasonal storage is that utilities would have a very large energy reserve at the beginning of the summer. This large energy reserve could be tapped to provide short-term emergency power, for example, in the event of an unforecasted period of high demand such as a heat wave.

Benefits to Disadvantaged Communities

Hydrogen deployed for seasonal energy storage and complementary decarbonization efforts can benefit the state's disadvantaged communities by reducing exposure to carbon dioxide emissions, nitrogen oxide emissions, particulate matter, and carbon monoxide. Under the direction of SB 535, the California Environmental Protection Agency (CalEPA) defines and identifies disadvantaged communities to target investments that would protect them (CalEPA, 2026). In 2017, more than 9.3 million Californians resided in disadvantaged communities (Rodriquez and Zeise, 2017; CalEPA, 2022). Regarding income, equity, and affordability, disadvantaged communities would benefit from the same statewide cost savings of power system cost minimization as all other ratepayers. However, an across-the-board cost reduction for ratepayers would provide a proportionately larger benefit to disadvantaged households who spend a larger percentage of their income on utilities.

Regarding greenhouse gas emissions, California's greenhouse gas inventory in 2022 totaled 371.1 million metric tons carbon dioxide-equivalent (MMT CO_2-e), of which 11 percent or 40.8 MMT CO_2-e were from the electric sector (CARB, 2024). Decommissioning the CO_2-e emitting fleet and replacing it with a hydrogen-fired fleet for seasonal energy storage would eliminate all 40.8 MMT CO_2-e. Therefore, disadvantaged communities stand to benefit at a rate of approximately 4 metric tons of CO_2 emissions eliminated per person per year. For comparison, the statewide population would stand to benefit at a rate of approximately one metric ton of CO_2 emissions eliminated per person per year.

California's electric sector consumed 564,282 million cubic feet of fossil gas in 2024, equal to 5.85×10^8 MMBtu. At the U.S. EPA-recommended emission factors (pollutant generation rates), California's disadvantaged communities stand to benefit from the elimination of approximately 0.3 kg of carbon monoxide per person per year[8] and 0.05 kg of particulate matter per person per year.[9] However, since fossil power plants are disproportionately sited in low-income or disadvantaged communities, they are being more disproportionately impacted by higher emissions, therefore removing the plants would provide the greatest benefit to communities most impacted by pollution.

Hydrogen-fired gas turbines would still emit NOx, but the level would be controlled per legally binding U.S. EPA standards. Assuming those standards are not relaxed for hydrogen-fired turbines, disadvantaged communities stand to avoid 2.6–3 lb. NOx per person per year. Appendix D provides additional details on calculations regarding disadvantaged communities.

[8] 5.85×108 MMBtu * 2×10-2 lb carbon monoxide * 50 percent plants cited in disadvantaged communities / 9,352,731 disadvantaged people

[9] 5.85×108 MMBtu * 3×10-3 lb particulate matter * 50 percent plants cited in disadvantaged communities / 9,352,731 disadvantaged people

CHAPTER 4: Conclusion

Several key findings emerged from this project's research and analysis; from these, the team developed recommendations for both EPIC and California. Crucially, ongoing technological advancements across both the electric and other adjacent sectors may alter hydrogen's future prospects, making some applications more competitive and others less. Policies may also evolve in response to these technological evolutions. This report aims to provide insight into the best uses of hydrogen in California's electric power system, and to better inform investment decisions being made today. In this chapter, the team summarizes several findings and provides recommendations for EPIC's next investment cycle.

Research Findings

Hydrogen technologies for grid applications are not yet technically mature. Technologies must fully mature, especially gas turbines that burn pure hydrogen fuel and in-state or nearby underground hydrogen storage.

Hydrogen provides resource diversification, distinct operational characteristics, and is the lowest-cost option for storage at high E/P ratios. Systems that require large amounts of energy relative to power—such as those supporting seasonal energy shifting—benefit from low-cost, utility-scale storage with high E/P. Other emerging non-gas storage technologies show promise but cannot yet match the E/P ratios or costs of gas-based options, including hydrogen. Because gas storage and generation provide firm, dispatchable power, hydrogen—if technologies mature—would be the only zero-carbon, industrially scalable gas option available to meet these needs in an SB 100-compliant system.

If key hydrogen technologies achieve technical maturity but costs do not decline, hydrogen can still provide system value without subsidies. A $3/kg hydrogen production tax credit provisioned by the IRA would reduce total system costs by about 1.5 percent when hydrogen is used for seasonal storage but would not materially change the mix of least-cost resources for the SB 100 system.

Environmental impacts are not major limitations to hydrogen deployment. Decommissioning fossil gas generators and adding hydrogen for seasonal storage would eliminate ~2.6 metric tons of CO_2-equivalent per ratepayer per year. Regarding water, in the scenarios for which hydrogen reduces the cost of meeting demand, hydrogen would consume less than 0.1 percent of California's total water supply, which would be more than offset by the water savings achieved by retiring thermal generation facilities. Regarding air, hydrogen-fired turbines would reduce and likely eliminate carbon monoxide but increase NOx emissions. However, NOx emissions are strictly regulated, and existing mitigation technologies should satisfy these regulatory limits.

California would need far fewer hydrogen turbines than the number of fossil gas turbines used today. Hydrogen turbines in SB 100 would play a very different role than fossil gas turbines today. The ideal number of turbines cannot be known with perfect certainty today, but it would likely be 10 percent or less of the more than 200 fossil gas turbine fleet in California today.

The operating strategy of hydrogen resources is paramount: It can determine whether hydrogen increases or decreases system costs. Hydrogen can also potentially complement offshore wind generation by smoothing interannual generation volatility. Subsequent discussions, studies, decisions, and technology development and deployment must explicitly characterize how hydrogen technology will be both integrated and operated.

Recommendations

Do not invest in blended hydrogen fossil gas fuel systems. Blending at low-percentage hydrogen hardly decarbonizes and does not incentivize suppliers to work toward the pure hydrogen turbines needed for SB 100. Addressing unsolved technical challenges with high-percentage hydrogen turbines may be a better use of resources than blending projects.

Consider hydrogen for seasonal storage in zero-carbon SB 100 planning. A diurnal hydrogen cycle would likely increase system cost, but a seasonal storage cycle could decrease cost at today's technology costs. The first hydrogen power plant confers the preponderance of value by vastly reducing PV overbuild, potentially complementing offshore wind generation to enable multiyear storage. Other nascent technologies will have significant impacts on the relative costs and benefits of hydrogen on the system and should be closely tracked.

Fund research on underground hydrogen storage in depleted hydrocarbon reservoirs and saline aquifers. While underground hydrogen storage in salt caverns is technically feasible, there are few suitable salt deposits in the western United States. Little is known about the performance and cost of hydrogen storage in depleted hydrocarbon reservoirs and saline aquifers.

Defer deploying major hydrogen infrastructure to allow insights and learnings from ongoing studies and research to guide investments. Hydrogen technology performance remains uncertain, and many technologies are not commercially ready. In the near term, the ACES-Intermountain (Delta, Utah) project is the first of a kind SB 100-eligible zero-carbon hydrogen-to-power project (hydrogen production, storage, and conversion) and will deliver critical performance, safety, and cost data that will reduce uncertainty for EPIC investment decision-making. Data of particular importance include: the net plant efficiency (at the fence line), NOx production rate, turbine turndown, the additional cost of NOx control, and hydrogen storage loss rates. Updated techno-economic analyses could be conducted when data from the ACES-Intermountain project becomes available.

Fund hydrogen turbine R&D only as a supplement to national funding. The federal government supports a robust advanced turbine research program, with more than $120 million in current project funding (DOE, undated-f). By aligning with and complementing these investment efforts, California can leverage this research while investing more heavily in other SB 100 strategies that are more likely to yield significant decarbonization benefits such as PV, wind, and LIBs. The marginal benefit of hydrogen investments toward atmospheric greenhouse gas reduction would likely be modest relative to these other technologies.

Moreover, suppliers may not be adequately incentivized to accelerate research, development, and demonstration due to the small number of turbines California would aim to purchase. This could further increase the price premium to supply a California-only market, which would fall to ratepayers.

Deploy hydrogen when renewable generation accounts for a large percentage of total generation and the fossil gas fleet has been substantially decommissioned. As PV and LIB penetration increases, gas peakers become less important for reserve margins; instead, strategically operated gas-based resources for energy shifting can enable significant reductions in required renewable capacity.

List of Terms/Glossary

Term	Definition
AB	Assembly Bill
AEM	alkaline exchange membrane
ARCHES	Alliance for Renewable Clean Hydrogen Energy Systems
ARL	adoption readiness level
BESS	battery energy storage system
BOP	Balance-of-plant
CAES	compressed air energy storage
CalEPA	California Environmental Protection Agency
CARB	California Air Resources Board
CCS	carbon capture and storage
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CRF	capital recovery factors
DNV	Det Norske Veritas
EJ	exajoule
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
E/P	energy-to-power ratio
GW	gigawatt
GWh	gigawatt-hour
GWP	global warming potential
H_2	hydrogen
HHV	higher heating value
IEPR	California Energy Commission Integrated Energy Policy Report
ISO	California Independent System Operator
IOU	investor-owned utility
kW	kilowatt
kWh	kilowatt-hour
LCOE	levelized cost of electricity
LFP	lithium-iron-phosphate
LHV	lower heating value

Term	Definition
LIB	Li-ion battery
Li-ion	lithium-ion
MW	megawatt
MWh	megawatt-hour
NIB	Na-ion battery
NMC	nickel-manganese-cobalt
OEM	original equipment manufacturers
OCC	overnight capital cost
OPEX	operating expenditure
PEM-WE	proton exchange membrane water electrolyzer
PPI	U.S. Producer Price Indices
PV	solar photovoltaic
SCR	selective catalytic reduction
SDS	safety data sheet
TRL	technology readiness level
TSAC	total system annuitized cost
TWh	terawatt-hours
U.S. EPA	U.S. Environmental Protection Agency
VRFB	vanadium redox flow battery

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Project Deliverables

- Technology Metrics Report
- PowerPoint Briefing A: Summary of Results of Task 2
- CPR Report #1
- PowerPoint Briefing B: Summary of Results of Task 3
- CPR Report #2
- PowerPoint Briefing C: Summary of Results of Task 4
- Knowledge Transfer Summary Report

ENERGY RESEARCH AND DEVELOPMENT DIVISION

APPENDIX A: Technology Metrics

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Appendix A: Technology Metrics

This technology metrics assessment presents a range of metrics for zero-carbon electric power system technologies appropriate for California's electricity grid. The assessment focuses on hydrogen technologies but also considers complementary and competitor technologies with details describing the economic, performance, and environmental impact metrics associated with hydrogen technologies and infrastructure. This suite of metrics serves two purposes. First, the metrics are of value in representing a compilation of current techno-economic data relevant to the use of hydrogen for California's electric power system. Second, they are inputs and a companion to the system modeling in Task 3 of this project, in which the team examined cost and performance of different arrangements of electricity generation and storage technologies.

Technology Categories and Metrics

The prospects for the use of hydrogen in California's electric power system depend on operational characteristics, costs, the availability of hydrogen, and the evolution of electric power technologies that could be used in conjunction with, or instead of, hydrogen. Consequently, the metrics covered in this report include those for producing electricity from hydrogen as well as a suite of alternative storage technologies. The emphasized technologies are solar photovoltaics (solar PV or PV), wind turbines, water electrolyzers to produce hydrogen, underground caverns to store hydrogen, gas turbines to produce electricity from hydrogen, pipelines to transport hydrogen, and the Li-ion battery (LIB).

Metrics cover cost and performance characteristics and include capital and operating costs, efficiencies, equipment lifetimes, and additional metrics specific to individual technologies. The team also examined technologies not modeled in Task 3 of this project and provided rationales for why they are omitted. Finally, the authors include estimates of projected hydrogen demand in other (nonelectric power system) sectors to provide a sense of relative scale of demand among different sectors. This can help support qualitative arguments for the feasibility of cost-sharing for hydrogen production and storage among sectors.

Methods

The team first conducted a broad search of published literature for cost and performance data. Literature sources included academia, national laboratories, government agencies, consultancies, and other sources. Recent estimates for many of the metrics were found in the literature, particularly from the U.S Department of Energy (DOE). All values were adjusted to today's dollars using inflation.

While a substantial amount of current metric information was available in the literature, metrics for some technologies, particularly hydrogen-fired gas turbines, were not readily available. For these technologies, the team developed estimates based on guidance from subject matter experts. The research team met with technical representatives from the three major power turbine suppliers (GE Vernova, Siemens, and Mitsubishi Power), an electrolyzer supplier, an iron-air battery supplier, an industrial gas company, and an underground hydrogen gas storage developer. The details of how these cost estimates were developed are described in the sections below.

California Senate Bill 100 (SB 100) requires 100 percent zero-emissions retail electric power sales by 2045, meaning that the grid must transition to zero-emissions over the course of the next 20 years. Per CEC's guidance, this report assumes that SB 100 objectives will essentially be met. Cost projections in future years are primarily based on learning rates, generally following a Wright's Law approach (Wright, 1936; Schmidt, 2017, IEA, 2020a). Energy infrastructure takes time to build out, therefore modeling must account for the evolution of costs and performance over the course of the deployment. In some cases, technologies remain precommercial today and are therefore unlikely to experience meaningful cost reductions by 2045; accordingly, most costs are estimated for today and 2045. This approach generalizes the observed exponential decrease in the cost of technologies with the extent of market deployment, with learning rates being greatest for new technologies and decreasing as the technology matures. Mature, deployed technologies have low learning rates and costs change marginally with further deployment. Among the challenges of using learning rates to project future costs is that mapping the extent of deployment to a specific year is difficult. The details of how learning rates are estimated and applied vary among individual studies; these are discussed in the narrative sections.

Technology Metrics

The tables below present metrics for each relevant technology. The research considered numerous characteristics and aimed to distill these down to metrics such as efficiency, cost, and key operational constraints. When available, an example of a relevant pilot or first-of-a-kind system is highlighted. Metrics were compiled and quantified from the synthesis of a wide range of sources. Some metrics are more uncertain than others, and forecasts of how values will evolve over time are inherently uncertain. Uncertainties are discussed in the narrative accompanying each technology's metrics table.

A Note About Costing

In accordance with best practice, cost data are presented in terms of overnight capital cost (CAPEX), fixed operating cost, and variable operating cost (OPEX) (National Energy Technology Laboratory, 2021; Bruckner et al., 2014). While many studies present "levelized" costs for individual technologies and systems, such values are necessarily dependent upon important operational choices such as capacity utilization and cycle times and intervals. Because these are exactly the types of choices explored in this modeling, the team opted to treat them as independent parameters and decouple them from costs.

SB 100 Eligible Primary Power

Solar Photovoltaics

Solar PV generators are manufactured into panels comprised of PV cells. The panels can be assembled into numerous configurations including utility, rooftop, commercial, community, hybrid, and microgrid designations based on the total project capacity, site, and grid interconnection (Solar Energy Industries Association, 2023; Annual Technology Baseline (ATB), 2024).

The cost and performance baseline used for modeling is a utility-scale PV facility with single-axis tracking. Utility-scale systems are the least-cost CAPEX per unit power and least-cost operating expenditure per unit power among assembly types, excluding off-grid PV. Rooftop PV capacity is likely to increase substantially over the next several decades; however, the load (demand) used in this project's modeling is taken from the California Energy Commission Integrated Energy Policy Report (IEPR) Commissioner Workshop on the California Energy Demand Forecast which already incorporates detailed capacity additions of behind-the-meter rooftop PV, energy storage, energy efficiency, and fuel substitutions (CEC, 2023b). In practice, the great majority of installed and announced capacity is utility-scale (Seel et al., 2024). Dual-axis tracking is much less common as it increases both the installed cost and maintenance costs but only marginally increases capacity factor (EIA, 2024a). Accordingly, cost and performance assume the characteristics of baseline of utility-scale PV (Table A.1), and subsequent modeling will apply sensitivity analyses and a discussion of the results.

Table A.1: Solar PV, Utility-Scale, Single-Axis Tracking

Metric	2024	2045	Unit
Overnight Capital Cost, Sargeny & Lundy	1,502	-	$/kW-AC
Overnight Capital Cost, NREL ATB	1,379	628	$/kW-AC
Overnight Capital Cost, RAND modeling	1,441	-	$/kW-AC
Overnight Capital Cost, RAND modeling, high	-	1152	$/kW-AC
Overnight Capital Cost, RAND modeling, low	-	393	$/kW-AC
Installed Cost, Capacity-Weighted Mean, LBNL	1,430	-	$/kW-AC
OPEX, fixed, Sargent & Lundy	20	-	$/kW/y
OPEX, fixed, NREL ATB	22	14	$/kW/y
OPEX, fixed, RAND modeling	21	21	$/kW/y
OPEX, variable	0	0	

Source: EIA 2024a, NREL Annual Technology Baseline 2024, Barbose et al. 2024

All balance-of-system costs, grid interconnection, and owner's costs are included in the 1,502 $/kW-AC overnight capital cost metric that was modeled and costed by Sargent & Lundy (EIA, 2024a). These systems would all be required to add new utility-scale capacity to the California grid. The 1,379 $/kW-AC and 628 $/kW-AC overnight capital cost metrics from NREL's ATB include balance-of-system costs in the 2024 cost and make favorable assumptions about cost declines (ATB, 2025-c). Given close agreement between the NREL, LBNL, and Sargent & Lundy figures for today's costs, the team used the average of NREL and Sargent and Lundy which report overnight capital cost (versus installed cost). The close agreement between Sargent and Lundy (an engineering firm) and NREL and LBNL (applied science and engineering national laboratories) suggests they are satisfactory for informing long-term investment decision-making.

To project the cost of utility-scale solar in 2045, consider that the national rate of cost decline has averaged 10 percent annually over the past 15 years (Seel et al., 2024). However, this decline was significantly higher between 2015 and 2019, while more recent years, 2021-2024, have seen a slower rate, averaging 6 percent annually (Seel et al., 2024). NREL assumes a linear cost reduction from the present to 2045; their 2045 cost metric declines by approximately half from 2024 to 2045. In contrast, applying the 6 percent annual decline rate for the entire system, PV module plus balance-of-system parts, interconnection, EPC, and owner's costs, from today out to 2045 results in 393 $/kW-AC, roughly 35 percent below NREL's estimate. Instead, if applying the 6 percent annual declination rate to the PV module only, the result is 1,152 $/kW-AC, roughly 80 percent above NREL's estimate. Given recent historical price volatility, dependence on policy decisions, and wide uncertainty when following reasonable arguments to their conclusion, 2045 modeling scenarios will utilize 393, 628, and 1152 $/kW-AC figures corresponding to high, medium, and low future costs for solar PV capacity. Regarding fixed OPEX cost for modeling purposes, this category includes components such as maintenance labor, insurance, taxes, and administration. RAND was unable to identify compelling evidence demonstrating that this cost component should decline substantially in real terms by 2045. Note that fixed OPEX is distinct from *levelized* fixed OPEX, OPEX per unit electricity delivered, which has declined and could possibly decline further if engineers can increase the total, final electricity output of a solar panel at equal fixed OPEX (Wiser et al., 2020). Levelized fixed OPEX was not used in RAND modeling.

Wind Turbines

Wind turbines are another technology that generate SB100 eligible primary power. Wind turbines may be categorized as onshore, fixed offshore, or floating offshore (Wiser et al., 2021), and are often sited in locations with high wind resources (wind speed and air density) and proximity to roads, and away from parks and other protected regions (Rediske et al., 2021; Shorabeh et al., 2022). This analysis focuses on onshore and floating offshore because these are technologies California is targeting; fixed offshore are briefly discussed in the "Technologies Not Modeled" section of this appendix.

The CEC reported 6,284 MW of installed wind capacity in 2023, and 13,920 gigawatt-hours (GWh) of in-state generation via wind (CEC), the majority of which is onshore. Table A.2 provides overnight capital cost and OPEX values for onshore wind. Values provided are either the median (if reported) or average (if no median is reported) values. The reported uncertainty ranges are large, at times +/- 50 percent. Studies suggest that wind's value, distinct from cost, will be highly complementary to solar, providing power when solar PV cannot (Mejia et al., 2023). For this reason, wind turbine generators will importantly contribute to achieving SB100 goals. LCOEs vary; one report suggests $0.037/kWh by 2030 (Junginger and Louwen, 2020), and another suggests approximately $0.034/kWh by 2024 and $0.028/kWh by 2045 (Wiser, 2021).

Table A.2: Onshore Wind

Metric	2024	2045	Unit
Overnight Capital Cost, Sens et al.	1,596	1,275	$/kW
Overnight Capital Cost, NREL ATB	1,676	1,188	$/kW
Overnight Capital Cost, Sargent & Lundy, 200 MW plant	1,817	-	$/kW
Overnight Capital Cost, Sargent & Lundy, 150 MW retrofit	1,620	-	$/kW
Overnight Capital Cost, RAND	1,677	1,232	$/kW
OPEX, fixed, Sens et al.	19	14	$/kW-year
OPEX, fixed, NREL ATB	32	26	$/kW-year
OPEX, fixed, Sargent & Lundy, 200 MW plant	40	-	$/kW-year
OPEX, fixed, Sargent & Lundy, 150 MW retrofit	45	-	$/kW-year
OPEX, variable	0	-	$/kW-year

Note: Sens et al. values are converted from Euro 2020 to USD 2024. Sargent & Lundy values are converted from USD2023 to USD2024 with the location adjustment for Los Angeles, California.

Source: Sens et al., 2022; ATB; EIA, 2024a[10]

Because California offshore wind generation may be more likely to meet peak demand (Mejia et al., 2023) and will not interfere with land rights, there is interest in exploring this for California. Perhaps due to these reasons, AB 525 requires multiple California entities to work together to develop a strategic plan for offshore wind (LegiScan, 2021). While offshore wind can be either be fixed or floating, California's coastal bathymetry is more conducive to floating offshore wind. Thus, California has established a goal of 25 GW of floating offshore wind (CEC, 2023c). A CEC fact sheet suggests the 25 GW would be met by approximately 1,600 turbines located far enough offshore so as to not be visible from the shore (CEC, 2023c). This would require multiple locations. An early 2020 study by NREL researched five locations in California - Morro Bay, Diablo Canyon, Humboldt, Cape Mendocino and Del Norte – and suggested CAPEX costs were approximately 4,500 $/kW (Beiter et al., 2020). The offshore floating wind table does not include ranges but the team notes that they are very large, over 100 percent different among locations. Accordingly, the team first considers an average as a baseline value but applies detailed sensitivity analyses in the modeling phase of the analysis to examine the range of potential futures and determine their implications for hydrogen (Table A.3). One report estimates LCOE of approximately $50/MWh for floating by 2045 (Wiser et al., 2021). Senate Bill 605 also requires multiple California entities to begin research into related topics of wave and tidal energy (LegiScan, 2023). Little is known at this time; it may be possible to collate wave and tidal generation with offshore wind to smooth power variability (Gideon, 2021).

[10] Note: Sens et al. values are converted from Euro 2020 to USD 2024. Sargent & Lundy values are converted from USD2023 to USD2024 with the location adjustment for Los Angeles, California

Table A.3: Floating Offshore Wind

Metric	2024	2045	Unit
Overnight Capital Cost, Sens et al.	4,055	2,981	$/kW
Overnight Capital Cost, Beiter et al.	4,370	-	$/kW
Overnight Capital Cost, Beiter et al., high estimate	-	3,700	$/kW
Overnight Capital Cost, Beiter et al., low estimate	-	1,670	$/kW
Overnight Capital Cost, NREL ATB	-	4,611	$/kW
Overnight Capital Cost, RAND	4,213	-	$/kW
OPEX, fixed, Beiter et al.	107	68	$/kW-year
OPEX, fixed, NREL ATB	-	63	$/kW-year
OPEX, variable	0	-	$/kW-yea

Note: Sens et al. values are converted from Euro 2022 to USD 2024. Sargent & Lundy values are converted from USD2023 to USD2024 with the location adjustment for Los Angeles, California. Beiter et al. values are converted from USD2019 to USD2024.

Source: Assumed to be 1.2 times that of fixed offshore as given in Sens et al., 2022; ATB, 2025b; Beiter et al., 2020.

Hydrogen Energy Storage

Hydrogen energy storage requires three components: hydrogen production, hydrogen storage and transport, and power generation via hydrogen conversion (DOE, 2023a). While most hydrogen today is produced through steam methane reforming, the most discussed approach to producing hydrogen in the SB 100 zero-carbon system is water electrolysis powered by renewable electricity. Hydrogen would then be stored for future use and converted back into electricity when needed. The cycle is similar to the charge, storage, and discharge phases of battery energy storage. Compared to a battery, however, where all three components occur within a single device, hydrogen energy storage uses discrete devices, allowing the three cycle phases to operate independently in time and space, potentially providing flexibility.

Water Electrolyzers to Produce Hydrogen

A water electrolyzer is a device that uses electrical energy to split water into hydrogen and oxygen through a process called electrolysis. The hydrogen can be used as a fuel for electric power generation. Four key designs of water electrolyzer were identified: proton exchange membrane water electrolyzer, liquid alkaline, solid oxide, and anion-exchange membrane (DOE, 2023a; DOE, 2022-b). The four types are named for the electrolyte material used to conduct ions across the electrochemical cell. PEM-WE was identified as the electrolyzer technology best capable of techno-economically pairing with California’s SB 100 eligible (zero carbon) primary generation resources, which will be overwhelmingly dominated by solar PV (Ramadan, 2022). PEM-WEs also represent >90 percent of announced and under construction electrolyzers (Arjona, 2023). The other electrolyzer types are discussed in the “Technologies Not Modeled” section of this appendix.

Proton Exchange Membrane Water Electrolyzer

Proton Exchange Membrane water electrolyzers (PEM-WE) are a promising technology for generating zero-carbon hydrogen in California. PEM-WEs produce zero direct emissions, are efficient and compact compared to alkaline electrolyzers, and feature both excellent ramp capability and high turndown ratio. Their fast-ramping capability makes them excellent candidates for pairing with intermittent renewable energy generators. PEM-WEs can ramp to 100 percent in a couple of minutes which will also enable them to participate in the California Independent System Operator's real-time energy imbalance market; this may prove crucial for collecting ultra-low-cost electric energy, an expensive input and key hydrogen cost-driver (International Renewable Energy Agency, 2020; Ueckerdt, 2024; James, et al., 2024). PEM-WEs generate high purity hydrogen appropriate for sensitive microelectronics and fuel cell mobility offtakes. High capital cost is anticipated to remain a challenge as PEM-WE stacks rely on expensive raw materials and advanced manufactured materials and subcomponents (Bernt et al., 2018; Minke et al., 2021; Clapp et al., 2023; Riedmayer et al., 2023). PEM electrolyzer lifespans may fall short of liquid alkaline electrolyzers and impurities in water feedstock degrade performance and operational life, increasing OPEX (Becker et al., 2023).

Electrolytic hydrogen production technology was estimated to have a technology readiness level (TRL) of about 7 (system prototype demonstration in an operational environment) in September 2024 (Office of Technology Transitions, 2024) and the adoption readiness level (ARL) remains low (Office of Technology Commercialization). Nevertheless, PEM-WEs have recently entered pilot-scale deployment (Electric Hydrogen; Plug Power Inc; Cummins Inc, 2020). One stakeholder interviewed explained a deficiency with using the TRL scale for PEM-WE. In simplified terms, a technology can be judged TRL 9 (actual system operated over full range of expected conditions) for a specific application, but if the application is significantly changed, that same technology would no longer be considered TRL 9 *for the new application.* This leaves open the possibility that some PEM-WE being deployed today are optimized and commercialized for an application other than seasonal energy storage. In California, the CEC recently awarded electrolytic hydrogen production projects at small capacities for transportation purposes (Linde, 2023; Piper, 2022). Transportation applications requiring round-the-clock uptime at zero-tailpipe emissions are one of the best-fit applications for mobility-type hydrogen fuel cells (EPA, 2025b) and PEM-WE hydrogen production today is mostly deployed for these offtakes.

Numerous PEM-WE cost figures and forecasts have been reported. In 2022, MIT & Harvard conducted process and cost modeling of electrolysis systems and used a PEM-WE system cost of 1,200 $/kW (1,246 in 2024 USD) (Ramadan et al., 2022). In 2022, the National Petroleum Council sponsored a study that estimated 2,200 $/kW in 2025 and 1,300 $/kW in 2045 (National Petroleum Council, 2024). The EPRI's PEM-WE total plant CAPEX estimate is 1,842 $/kW in 2024 with a 2045 forecasted range of 538–1453 $/kW (Electrolysis Techno-Economic Analysis, 2024). In 2022, Electric Hydrogen reported a $1246/kW in 2024 USD (U.S. Producer Price Index (PPI)-corrected) (Electric Hydrogen, 2022). Electric Hydrogen is an original equipment manufacturer (OEM) and has sold PEM-WEs, but is known for confidentiality (Ward, 2024) and RAND has not yet been able to obtain real-world cost figures for their systems. In May of 2024, Strategic Analysis reported the average total installed capital cost of a PEM-WE system would be $949/kW in 2020 USD ($1,026 in 2024 USD) assuming a 1 GW/y manufacturing rate (James et al., 2024). It further projected that the future cost, at an unspecified year, could reach $807/kW (James et al., 2024). Also in May of 2024, the DOE Hydrogen and Fuel Cell Technologies Office reported an average installed capital cost of $2,000/kW in 2022 USD for a large, centralized production facility before taxes and incentives (DOE, 2024c). PPI-adjusting from 2022 to 2024 USD, this amounts to 2,075 $/kW. This report considers the recent Hydrogen and Fuel Cell Technologies Office program record as the most authoritative cost figure publicly known today. The program of record was conducted by several experts across DOE and DOE laboratories, vetted by domestic electrolyzer manufacturers, and was favorably compared against paywalled cost modeling efforts by S&P Global, the Hydrogen Council, Bloomberg New Energy Finance, and Lazard.

Some of the recent cost variation is due to financial volatility precipitated by the COVID-19 global pandemic. The PPIs for PEM-WE related hardware, Electrical Equipment Manufacturing (Federal Reserve Bank of St. Louis, 2025b), Chemical Manufacturing (Federal Reserve Bank of St. Louis, 2025a), Industrial Machinery Manufacturing (Federal Reserve Bank of St. Louis, 2025c), and General Purpose Machinery and Equipment (Federal Reserve Bank of St. Louis, 2025e), all experienced dramatic increases shortly after the 2020–2022 increase in the growth rate of M2 money supply (Federal Reserve Bank of St. Louis, 2025d). The growth rate of M2 has recently returned to pre-2020 levels and the PPI growth rates have likely returned to pre-pandemic rates suggesting that correcting cost figures to 2024 and/or re-evaluating in 2025 will clarify cost analyses. One stakeholder interviewed confirmed the applicability and importance of PPI analysis to this report. An update to DOE's Pathways to Commercial Liftoff: Clean Hydrogen report is anticipated by approximately end of CY2025. The CEC should continue to re-evaluate costs as new information is published.

As PEM-WE technology remains nascent, cost forecasting remains challenging. Bühler recently reviewed historical PEM-WE learning rates in literature and found reported rates span 4 percent to 36 percent (Bühler, 2024). In 2020, the Hydrogen Council forecasted a 13 percent cost reduction rate due to manufacturing volume learning (Hydrogen Council, 2020). The application of experience curve forecasting for PEM-WEs remains in infancy, and several limited papers on the topic refer to a single database (Bühler, 2024). Nevertheless, several useful insights can be extracted and synthesized for forecasting purposes.

In 2023, DOE forecasted the 2030 installed capital cost of PEM-WE at $500-600/kW (for a large, 80 MW system). The DOE previously set a goal of 250 $/kW for uninstalled capital cost by 2026 (DOE, undated-e).

In 2024, the Hydrogen and Fuel Cell Technologies Office published a new target of 500 $/kW with significantly higher efficiency by 2026 (Office of Energy Efficiency and Renewable Energy, 2024). This would require both a 75 percent cost reduction and a significant technology breakthrough in less than two years. Instead, recent PEM-WE costs have tracked equipment prices and labor rates (which have increased nominally). Indeed, the PEM-WE uninstalled capital cost reduction curve reached an asymptote in approximately 2011 (Satyapal, 2024). Consistent with theories of causes and sequencing of cost decline (Kavlak, et al., 2018; Farmer and Lafond, 2015), PEM-WE basic science may have saturated (Randolph et al., 2022). The

Hydrogen and Fuel Cell Technologies Office's shift in emphasis from basic science to "demonstration and enabling" appears to corroborate this (Satyapal, 2024; Office of Energy Efficiency and Renewable Energy, 2024). The majority of future cost reductions will more likely be achieved via Wright's Law, economies of scale, and supply chain network optimization (Randolph et al., 2022). Solar PV, which is much farther along its learning trajectory, has followed this underlying causal sequence of cost decline and has progressed at approximately 10 percent per year and 20 percent per doubling of capacity over the long run (Way et al., 2022; Ritchie, 2024). For LIBs, the volume-weight average pack cost declined by an impressive 21 percent per year from approximately 2010–2017 but deployment (LIB sales in GWh/y) remained very low during this time (IEA, 2024-a). From the time deployment reached relevant capacities (Walter et al., 2024; IEA, 2024-c) the cost reduction rate has slowed to approximately 5 percent per year (Bowen et al., 2019). The battery cost reduction rate versus capacity has been closer to 5 percent/GWh over the long run (up to ~1 TWh of capacity, from 1996-2020) (Way et al., 2022). PEM-WE systems are more complicated than either solar PV or LIB storage systems, and one should expect a lower long-run average learning rate for PEM-WE. Going forward, forecasting electrolyzer cost will likely be more accurately achieved as a function of industry size (manufacturing capacity), not time, per se. Through an interview with a major industrial OEM, RAND learned that industry's manufacturing rate is also currently controlled by policy which is rarely best described as a function of time (DOE, 2023a). Industry will likely wait to receive a signal that a scale-up trajectory can be reasonably profitable and de-risked. It is the scaling up that can unlock substantial cost declines.

Several entities tracking the global energy transition find that hydrogen technology deployment lags decarbonization objective timelines (Det Norske Veritas). In January 2024, McKinsey forecasted hydrogen beginning its contribution to the electric power sector globally in approximately 2045 (McKinsey & Company, 2024). Plug Power sees the U.S. refusing to accept foreign electrolyzers which would both reduce economic national security risks but slow electrolyzer and hydrogen economy deployment in the U.S. (Martin, 2024). Hydrogen technology uncertainty has been widely acknowledged, and most announced projects do not get built (BloombergNEF, 2024). If the global hydrogen industry deployment timeline substantially lags California's decarbonization timeline, California would have to absorb a higher unit cost to achieve 2045 decarbonization goals that depend on electrolytic hydrogen.

NREL's recent bottom-up manufacturing cost analysis update estimates that increasing manufacturing volume can reduce PEM-WE system unit cost by approximately 20 percent per ten-fold increase of manufacturing capacity (MW/y). At 10 GW/y, NREL estimates approximately a 50 percent reduction in cost from today's low manufacturing rate. The national hydrogen strategy also reported that the opportunity for system capital cost reduction is approximately 50 percent. The PEM-WE installed capacity increased annually as 13.4 MW, 18.5 MW, 67 MW, and 116 MW from 2021 through 2024, an impressive growth rate (DOE, 2021; DOE, 2022; DOE, 2023; DOE, 2024a; Wang, 2024). 73 percent of the planned firm capacity in 2021 was installed (not necessarily operational) as of mid-2024. Nevertheless, system capital cost has continued trending upward since the 2011 saturation value. In other words, no cost reduction has yet been realized in the U.S. due to economies of scale manufacturing despite impressive increases in installed capacity.

The PEM-WE manufacturing rate could also become bottlenecked by the rate of iridium metal production. The International Renewable Energy Agency conservatively estimated that 3 GW/y manufacturing capacity would strain iridium production while authors at Leibniz University estimated that 2 GW/y could exceed global iridium production capability (Minke et al., 2021). These estimates jeopardize realization of the best-case cost reductions due to economies of scale manufacturing.

Balance-of-plant (BOP) equipment represents more than half of the total system cost which brings further implications for investment decision-making (DOE, 2023a). The BOP for a small, decentralized system, such as a standalone light- or medium-duty vehicle fueling station, is distinct from that of a large, centralized plant. Cost reductions for small systems may not translate directly to cost reductions for large systems which are needed for the seasonal energy storage paradigm in California (Badgett et al., 2024).

Finally, the November 2024 election results may have important policy implications that will likely impact the hydrogen and renewable energy deployment timelines. The future of the Inflation Reduction Act and its associated incentives, including the hydrogen production tax credit, remains uncertain. Three of the seven hydrogen hubs might not have yet broken ground and therefore, might be at risk of losing Bipartisan Infrastructure Law funding (Skelton, 2024). The oil and gas sector may therefore remain competitive longer, crowding out green hydrogen technologies. Absent policy support, sustained inflation and high-interest rates hinder the highly capital-intensive investments required for clean energy infrastructure. The new administration may be unable to stop oil and gas winddown in California (Rust et al., 2024), but California will likely need national and global hydrogen buy-in to achieve its hydrogen-related goals. Collectively, these factors point toward a postponing of green hydrogen technology deployment, and the analysis therefore assumes a conservative baseline scenario of no PEM-WE cost reductions by 2045. Given recent changes in the policy and economic environment, an optimistic trajectory for PEM-WE could follow six years of cost increase (tracking inflation, approximately 3 percent per year) followed by approximately 4 percent cost declines per year (slightly less than battery cost reduction rate) from 2030 to 2045 resulting in $1,343/kW (2024 USD) in calendar year 2045 (Table A.4). Sensitivity analyses include the optimistic trajectory among other bounding and goal-oriented results to help guide EPIC investment decision-making.

Table A.4: PEM Electrolyzer, Large, Centralized

Metric	2024	2045	Unit
Installed Capital Cost	2,075	-	$/kW
System Capital Cost	2,200	-	$/kW
Overnight Capital Cost, optimistic trajectory	-	1,343	$/kW
OPEX, stack replacements	11%	11%	% of total installed capital per 40K hrs
OPEX, fixed, other	5%	5%	% of total installed capital
OPEX, variable	0.04	$/kg-H2	$/kg-H2
System Lifetime (Cost Recovery Period)	30	30	years
Ramp Rate	100% in ~1 min	100% in ~1 min	%/min
Efficiency, Lifetime-Average	57.5	55	kWh-e/kg-H2

Source: Hubert et al. 2024. 2022 USD were PPI-adjusted to 2024 USD.

Underground Hydrogen Storage

Considering the amounts of hydrogen required for any meaningful contribution to grid-scale energy storage, the only practical option for storing hydrogen is underground. This can be demonstrated with a simple computation: using the lower heating value of hydrogen of 33.3 kWh of power per kg (U.S. Department of Energy), a 400 MW turbine with an efficiency of 50 percent will require 24 tons of hydrogen per hour. Running even as little as 4 hours per day would require 96 tons of hydrogen each day, which is equivalent to 37 of the largest industrial hydrogen tanks available (Taylor-Wharton, undated). In addition to the issue of scale, surface storage is more expensive and more susceptible to safety risks from natural disasters (Abdin et al., 2022; Lackey et al., 2023).

The most commonly discussed types of underground storage facilities are manufactured salt caverns, depleted hydrocarbon reservoirs, and saline aquifers. All three types are commonly used for storing fossil gas, though underground hydrogen storage is only just emerging. Only a few underground hydrogen storage facilities exist in the world and, aside from some early attempts at storing hydrogen-rich coal gas, there are no hydrogen storage facilities in depleted hydrocarbon reservoirs or saline aquifers (Lackey et al., 2023; Tarkowski, 2019).

A number of recent studies have examined technical and economic performance of underground hydrogen storage (Chen et al., 2023; Lackey et al., 2023; Lin, Xu, and Moscardelli, 2024; Lord, 2014; Mishra et al., 2023; Okoroafor et al., 2022; Talukdar et al., 2024; Tarkowski, 2019). The CEC also has an ongoing study looking at the feasibility of underground hydrogen storage in California. The team also received a detailed cost estimate from an engineering-construction firm that is a leader in salt cavern storage facility development. This work has resulted in several cost estimates that are in reasonable agreement (Table A.5). The main cost elements include site development costs, cushion gas (gas that must remain in the storage facility to maintain system pressure), compressor costs, and well and pipeline costs. While underground hydrogen storage is still an emerging capability, the technology closely follows that of underground fossil gas storage, which is a mature technology. Hence the team assumes no cost reduction between now and 2045.

Uncertainties remain in the performance of underground hydrogen storage, particularly in depleted hydrocarbon reservoirs and saline aquifers. Potential issues such as leakage, reactivity with host rock, and bacterial reactions affect the efficiency and lifetime of a storage facility. For example, experience with storing coal gas (50 percent–60 percent hydrogen) in saline aquifers in Europe found that methanogenic bacteria quickly convert hydrogen to methane, greatly limiting the storage lifetime (Tarkowski, 2019; Wu et al., 2024). The potential hydrogen storage volume in depleted hydrocarbon reservoirs is more than necessary for storage volumes estimated in our modeling (Chen et al., 2023; Lackey et al., 2023; Okoroafor et al., 2022), but until the performance characteristics are better understood, salt caverns appear to be the leading candidate for underground hydrogen storage. Two new salt caverns for underground hydrogen storage are currently under construction at the ACES Delta facility in Delta, Utah (ACES Delta).

Table A.5: Geologic Storage

Metric	Cost	Unit	Source
Capital cost, salt	0.2–1.1	$/kWhH2	IEA (2023)
Capital cost, depleted HC reservoir	0.03–0.6	$/kWhH2	IEA, 2023
Capital cost, salt	5.36–6.00	$/kWhH2	PNNL (2023)
Capital cost, salt	0.31–0.4	$/kWhH2	Mishra et al. (2023)
Capital cost, depleted HC reservoir	0.34–0.53	$/kWhH2	Mishra et al. (2023)
Capital cost, salt	0.51	$/kWhH2	Chen et al. (2024)
Capital cost, depleted HC reservoir	0.18	$/kWhH2	Chen et al. (2024)
Capital cost, salt	0.033	$/kWhH2	Talukdar et al. 2024
Capital cost, salt	2.37	$/kWhH2	Abdin et al. (2022)
Capital cost, salt	0.77	$/kWhH2	Supplier estimate
Capital cost, tanks	23.08	$/kWhH2	Abdin et al. (2022)
OPEX, variable, salt	0.00252	$/kWhH2	IEA (2023)
OPEX, variable, depleted HC reservoir	0.00429	$/kWhH2	IEA (2023)
OPEX, fixed, salt	0.01887	$/kWhH2/y	IEA (2023)
OPEX, fixed, depleted HC reservoir	0.0074	$/kWhH2/y	IEA (2023)
OPEX, variable	0.0005125	$/kWh/y	Balliet and Casteel (2023)
Loss Rate	<1	percent/month	Abdin et al. (2022)
Calendar Life	30	years	PNNL (2023)
Efficiency	78–92	percent	Okoroafor et al. 2022
Efficiency	92	percent	Abdin et al. (2022)

Source: Included in table

Hydrogen-Fired Gas Turbines

A gas turbine is a type of internal combustion engine used for generating electricity by converting energy from fuel (gas or liquid fuels) into mechanical energy, which is then used to drive a generator. Gas turbines are widely used in power generation because of their ability to produce large amounts of power and energy efficiently and quickly from high energy density fuels. Gas turbines operate on the Brayton cycle, which involves compression, combustion, and expansion processes (Boyce, 2012). This report focuses on frame-type gas turbines. In contrast, aeroderivative-type turbines are typically rated for lower power (perhaps 10 times lower, at which point other power/energy options may be preferred), require larger capital expenditure per unit of net power output, and are less efficient while still requiring complicated adjacent infrastructure of electric power transmission interconnection and a fuel pipeline (EIA, 2024a). OEMs informed RAND that the principal avenue of research and development for hydrogen-fired gas turbines is for frame-type turbines. For higher fuel conversion efficiency, power plants combine gas turbines with heat recovery steam generators and steam turbines that operate on the Rankine cycle (EIA, 2024a). These are called combined cycle power plants and are preferred when high fuel conversion efficiency is desired. Combined cycle plants are increasingly the norm and will very likely be favored for converting expensive hydrogen fuel.

In accordance with California Senate Bill 100 which undergirds this project's scope, this project focuses on hydrogen-fired gas turbines operating on 100 percent hydrogen fuel by volume because burning a lower percentage fuel mixture does not decarbonize power production. General Electric estimates that 30 percent H2 by volume provides approximately 10 percent decarbonization benefit relative to natural gas operation while even 90 percent H2 by volume accomplishes only 75 percent decarbonization (Goldmeer, 2019). Most H2-fired gas turbines are incapable of burning 100 percent hydrogen, and the advanced designs of high percentage H2-fired gas turbines that OEMs are developing have not yet been commercially deployed (Noble et al., 2021). RAND discussions with OEMs suggest that some of the technologies needed for 100 percent H2 gas turbines are below technology readiness level (TRL) 7 today with some judged closer to TRL 4 (Hughes, Berry, and Weber, 2021; U.S. Department of Energy, 2022-d). RAND research, confirmed by stakeholders, further determined that numerous gas turbine and balance-of-plant components would have to be upgraded to retrofit a power plant from low-percentage H2 capability (<30 percent) up to near-100 percent capability (Goldmeer, 2019). One OEM suggested that retrofitting from low percentage H2 to nearly 100 percent H2 would require a near-total power plant rebuild. One pathway to near-100 percent H2-fired power plants would use low percentage H2 power plants as a steppingstone to 100 percent H2 operation. But low percentage deployment does not contribute to solving unique, outstanding technical challenges encountered with 100 percent H2 fuel (EPRI, 2022b), nor does it meaningfully deploy or stimulate the balance-of-plant hardware supply chains that would be required for 100 percent H2 operation. To make headway toward 100 percent H2 operation per SB 100, OEMs would need to make advances across the systems engineering, materials science, and failure phenomena (EPRI, 2022b).

In summary, low percentage H2 fuel does not substantially contribute to the research and development needed to achieve SB 100, combustion of 100 percent H2 fuel, nor does it meaningfully decarbonize power production today. After synthesizing these findings, it was deemed unnecessary to focus on low percentage H2 power plants given California's aim to achieve SB 100 goals by 2045.

Per the discussion above, technology metrics most pertinent to the EPIC investment decisions are compiled in Table A.6. These metrics comprise a set of key characteristics to enable relevant system-level comparison between hydrogen technologies and competitor/complement technologies.

Table A.6: H2 Gas Turbine, Utility-Scale, Frame-type

Metric	2024	2045	Unit
Overnight Capital Cost	-	1,429	$/kW
Overnight Capital Cost	-	1,180	$/kW
Overnight Capital Cost	6,726	-	$/kW
OPEX, fixed	15.51	15.51	$/kW-y
OPEX, variable, non-fuel	3.33	3.33	$/MWh
OPEX, variable, fuel	calculated	calculated	$/kg
Plant Operating Lifetime	40	40	y
Cycle Type	combined	combined	-
Part-load turndown	50%	50%	%
Ramp rate from hot idle	50	50	MW/min
Startup from cold shutdown	48-72	48-72	h
Net Plant Efficiency, rated power (LHV)	63%	63%	%
Net Plant Efficiency, half-load (LHV)	42%	42%	%
NOx control method	SCR	SCR	-

Source: EIA 2024, Boyce 2012, Goldmeer 2022

Stakeholders and literature confirmed that gas turbines have a 50 percent part-load turndown and that startup from cold shutdown time averages 48-72 hours. Taken together, these constrain the operating strategy for the turbine as part of a seasonal energy storage paradigm.

The ASTM-approved Gas Turbine Engineering Handbook cites a value of 65 percent efficiency for advanced, combined cycle gas turbine power plants (Boyce, 2012). GE Vernova and Siemens both published values of 64 percent efficiency (GE Vernova, undated; Siemens Energy, undated). Proponents largely agree upon >60 percent combined cycle efficiency for contemporary, advanced technology utilizing higher temperature, pressure ratio, and axial-flow compression (Boyce, 2012; Gülen and Curtis, 2024; Winters, 2023) and OEMs RAND interviewed suggest >60 percent will be achieved. However, EIA compiled power plant heat rates (efficiencies) and reported that modern, combined cycle plants brought online since 2010 achieve 49 percent efficiency (EIA, 2023c). Moreover, California's natural gas combined cycle nameplate EIA capacity increased from ~zero in 2001 to ~17,000 MW in 2015 but the average efficiency remained approximately constant over this time with an efficiency in 2015 of 47 percent (CEC, 2017). Sargent & Lundy specify a 2.8 percent efficiency loss for auxiliary power demands in a 1x1x1 fossil gas combined cycle power plant. The power plant assumes a wet (open circuit) cooling tower rejects heat. If local water shortage or cost forces the use of a dry (closed-circuit) cooling tower, another small efficiency penalty would be incurred. However, auxiliary and cooling losses cannot explain an efficiency difference of 65 percent versus 47 percent.

Efficiency can be reported referenced against the lower heating value (LHV) or the higher heating value (HHV) of fuel. For gas turbines, efficiency should be reported against the LHV because the enthalpy of water condensation is not captured and converted to useful work in the overall process; steam exits the steam turbine as a gas, not a liquid. Some reports list efficiency in terms of the HHV but General Electric and Siemens correctly report efficiency in terms of the LHV (Goldmeer, 2019).

A NOx/efficiency/CAPEX tradeoff also remains unsolved for 100 percent H2-fired gas turbines. Thermal efficiency increases with temperature (Brayton cycle), but NOx generation also increases exponentially with H2 fuel percentage (Myers et al., 2021) because H2 combustion burns at higher flame temperature which promotes N2 dissociation and recombination with O2 resulting in NOx (GE Vernova, 2025). This challenge has not yet been commercially solved by OEMs. With today's technology, a H2-fired plant that would be both SB 100- and NOx-compliant would have to accept at least one of the following three penalties: 1) temperature reduction and/or fuel dilution resulting in efficiency loss, 2) increased CAPEX cost for a larger SCR unit to control NOx, or 3) NOx emissions increase, in conflict with today's environmental regulations.

There are also design implications for 100 percent H2-fired gas turbines beyond the scope of this study. Gas turbines are commonly designed to permit dual fuel capability to de-risk single-fuel scarcity (Boyce, 2012). SB 100 compliant hydrogen gas-fired turbines may still be capable of firing fossil gas, however, they will face a separate design challenge: H2 is the only zero-carbon, SB 100-compliant fuel. The second fuel would emit CO2 on site and therefore be out-of-compliance. If the zero-carbon constraint were relaxed and replaced with a net-zero carbon constraint, the power plant could incorporate a carbon capture and storage system. However, this would imply plant designs with much more CAPEX versus legacy plants and three pipelines servicing the plant: H2 (primary fuel), fossil gas (secondary fuel), and CO2 (captured and transported away for sequestration). This project was not scoped to conduct a detailed examination of this problem.

Evidence suggests that no hydrogen-fired gas turbine cost reductions will be achieved between today and 2045. Fossil gas-fired power plants are mature and largely optimized today. Advanced technology 100 percent H2-fired gas turbine power plants do not yet exist and may not see first-of-a-kind deployment until the 2040's. GE Vernova's first <20 percent H2 blend-fired gas turbine was successfully demonstrated in 2022 using an 7HA.02 combustion turbine (GE Vernova, 2022; Power Technology, 2024). This is an impressive achievement, but the 7HA.02 technology cannot achieve complete decarbonization and therefore would not be SB 100 compliant. From a different angle, the cost breakdown of fossil gas-fired gas turbine electric power is fuel-dominated today (Weiland, Lewis, and Hackett, 2024); CAPEX and nonfuel OPEX together account for 1/4 of lifecycle cost. With H2-fired gas turbines, the fuel cost is all but guaranteed to go up. This will remove pressure for OEMs to minimize capital cost of the gas turbine. All of this points toward low likelihood of capital cost declines before 2045. If California reaches 100 percent decarbonization by 2045 per SB 100, it is likely to pay first-of-a-kind or early commercial prices and reap little or no economies of scale benefit.

Hydrogen Pipelines

The preceding sections establish the need for hydrogen pipelines to service hydrogen-fired gas turbine power plants. A decade ago, the National Institute of Standards and Technology suggested that a hydrogen pipeline might be very expensive (NIST, 2015). Recent studies indicate hydrogen pipeline materials can be made more cheaply than expected. Costs range as a function of materials, equipment, labor, and location. A widely used cost model suggests a cost penalty of only about 10 percent for hydrogen relative to natural gas pipelines (Argonne National Laboratory, 2015; U.S. Department of Energy, undated-a). Brown & Redi (2018) show that for Class 1 pipelines, hydrogen pipe materials may be two-thirds the cost of fossil gas pipes for 1,000 PSIG-rated 30” diameter pipe (Brown, Reddi, and Elgowainy, 2022).

For this analysis, the team costs materials labor, right of way/permitting, and miscellaneous costs for pipelines to transport hydrogen as a function of length and diameter escalated to 2023 USD (Brown, Reddi and Elgowainy, 2022; McCoy and Rubin, 2008; Parker, 2004; Rui et al., 2011). Three of the four models consider location, and costs are cheaper in California compared to elsewhere. The newer three models determined 30” diameter, 100-mile-long pipeline between $1.5-1.7M per mile in overnight capital cost. For conservative estimation, the team used the upper end of $1.7M/per mile, with a corresponding pipeline operations and maintenance (O&M) of $10K per mile per year (Morgan et al., 2024).

Complementary Energy Storage Technologies

Lithium-Iron-Phosphate Battery

LIB are an exceptional storage technology for complementing intermittent, primary renewable energy generators (IEA, undated). When paired with bi-directional, grid-forming inverters, LIB can provide numerous grid services and appear poised as the energy storage workhorse of the decarbonized electric power system (Kroposki, 2024; Lasseter, Chen, and Pattabiraman, 2020; Lin et al., 2020). Overall, LIB storage systems are modular and can be strategically located across balancing authorities which may defer costly upgrades to transmission and distribution infrastructure. They also support stepless expansion, making them suitable for large-scale electric energy storage projects that may need to grow over time, for example, if financial or permitting challenges slow project development. Round-trip efficiency is high (approximately 85 percent), and efficiency increases when charging and discharging at part-load.

Lithium-iron-phosphate (LFP) batteries are emerging as a promising low-cost LIB technology for utility-scale energy storage and some manufacturers are moving from offering nickel-manganese-cobalt (NMC) type LIBs to LFP LIBs (Volta Foundation, 2023). The iron phosphate material lowers thermal runaway risk (Golubkov et al., 2015) making LFP batteries intrinsically safer than cobalt-containing LIB chemistries, all else equal. This makes LFP batteries well-suited for large-scale installations where safety is paramount. The LFP chemistry offers a longer cycle life compared to other LIB chemistries, which lowers the lifetime capital cost per unit of energy stored and delivered. LFP avoid expensive and potentially scarce minerals such as cobalt and Class 1 nickel which also lowers supply chain risk. LFP uptake and market share are rapidly increasing, and cell cost is dropping (Catsaros, 2023; IEA, 2024a). Cells manufactured in China may be substantially cheaper than U.S.-manufactured cells, but these data are harder to verify, and reliance upon Chinese-manufactured cells introduces additional risks (Shahan, 2024). LFP batteries have lower energy density per unit mass compared to some other battery chemistries, but this is not a key concern for stationary applications.

Moreover, as grid-application battery demand increases, manufacturers will tailor cells for higher energy versus higher power which will further reduce cost (Argonne National Laboratory, undated).

Sargent and Lundy conducted a full engineering preanalysis to determine $436/kWh for a utility-scale, Li-ion, battery energy storage system (BESS) inclusive of inverters, transformer, and interconnection switchgear to interface with the electric grid (EIA, 2024). NREL and Pacific Northwest National Laboratory (PNNL) BESS estimates come close to Sargent and Lundy so the authors treat the conservative (higher) estimate as baseline (NREL, 2024a; PNNL, undated-a) (Table A.7). Lower estimates are incorporated into the sensitivity analyses. PNNL forecasts approximately $118/kWh system cost in 2045 while NREL forecasts $207/kWh. From the detailed engineering analysis, $207/kWh would require a nearly 80 percent cost decline in the battery unit with no other cost reductions. Accordingly, the authors treat this as an optimistic scenario. In contrast, at the recent cell-plus-pack cost decline trajectory of 4 percent per year (Catsaros, 2023), the battery module would be reduced to 40 percent of today's cost which translates to $262/kWh in 2045, assuming BOP and soft costs are unchanged by 2045. $118/kWh, $207/kWh, and $262/kWh establish the range of trajectory optimism and will be incorporated into future scenario modeling.

Table A.7: LFP Battery Storage, Utility-Scale

Metric	2024	2045	Unit
Overnight Capital Cost, energy basis	436	-	$/kWh
Overnight Capital Cost, energy basis	390	207	$/kWh
Overnight Capital Cost, energy basis	349	118	$/kWh
Overnight Capital Cost, energy basis	-	207	$/kWh
Overnight Capital Cost, energy basis	-	262	$/kWh
OPEX, fixed	40	-	$/kW-y
OPEX, fixed	78	41	$/kW-y
OPEX, variable	0	-	$/kWh
Plant Lifetime (Cost Recovery Period)	20	20	y
Round Trip Efficiency	85%	85%	%

Source: EIA 2024a, NREL Annual Technology Baseline 2024, PNNL 2023

Iron-Air Battery

Iron-air batteries have been studied for decades but remain at a nascent stage. The first commercial prototypes have been awarded and are under construction today (Form energy, 2023). Form Energy self-reports the metrics in Table A.8 but did not respond to the team's request for interview and their numbers have not yet been verified by a neutral, third-party (CEC, 2023d; Form energy, 2020).

Table A.8: Fe-Air Battery Metrics, Utility-Scale, LDES role

Metric	Today	2045	Unit
Overnight Capital Cost, energy basis	3.75 - 11.50	-	$/kWh
OPEX, fixed	40	-	$/kW-y
OPEX, variable	0	-	$/kWh
Lifetime (Cost Recovery Period)	25	25	y
Round Trip Efficiency	47%	47%	%

Source: Form Energy 2020

Nongrid California Hydrogen Offtakes

While largely outside the scope of this project, nongrid hydrogen offtakes may influence the rate of cost evolution of hydrogen technologies. On-grid hydrogen is not operating in isolation; there will be a market for nongrid hydrogen as well. This section provides a short description of estimated hydrogen demand in other sectors. If the CEC decides to pursue more research into hydrogen supply and demand (perhaps, in order to leverage other sectors into reducing costs for hydrogen use in electricity), there will likely be a need to fund more research into these topics.

Multiple entities have estimated hydrogen use in the future:

- IEA (2020) indicates that by 2050, the world will use 287 MtH2 per year. Most will be used in transportation (23.2 percent of overall use), followed by industry (21.9 percent), power (19.2 percent), synfuel production (14.2 percent), buildings (9.3 percent), ammonia production (6.4 percent), and refining (5.9) (IEA, 2020). By 2070, the world is estimated to use 519.1 MtH2 per year, with nearly a third of the demand from transportation (and power only slightly increasing to 72.9MtH2 per year, or dropping to 14 percent of total). Of the three global studies considered, IEA (2020) suggests the highest percentage of hydrogen demand will be for power. However, note their newer 2024 outlook does not include hydrogen as a major contributor to the electricity grid in 2040 (IEA, 2024-d).
- Det Norske Veritas (DNV) recently downgraded hydrogen's future use (DNV, 2024). They indicate that in 2050, the world demand for hydrogen and its derivatives will be approximately 188 Mt H2 / yr. Of this, 55 percent will be for transportation (e-fuels, NH3, or hydrogen), 39 percent will be for manufacturing, 3 percent for buildings, and only 1.8 percent for power or electricity generation.
- McKinsey (2024) suggests that by 2050, hydrogen demand will be 175–530 MtH2 per year (Gulli et al., 2024). Depending on the scenario, they also predict approximately a third of demand will be from transportation, followed by existing industrial use, heating, new industrial use, and power generation (which is ~ 5 percent). Specifically, in a world where commitments are achieved, McKinsey predicts 463 MtH2 per year, with 40.6 percent for transportation, 34.8 percent for existing or new industrial, 16.8 percent for heating, and 7.8 percent for power. However, it is unlikely the commitments will be

achieved; the world is likely similar to the IEA estimate or the DNV estimate. In a world more in line with the IEA estimates, McKinsey predicts 35.5 percent for transportation, 44.5 percent for existing or new industrial, 14 percent for heating, and 6 percent for power. In a world in line with the DNV estimates, McKinsey predicts 17 percent for transportation, 70.4 percent for existing or new industrial, 10.8 percent for heating, and 1.7 percent for power.

Note there is one entity that focuses on California: the ARCHES group (ARCHES, 2024; Galiteva et al., 2024). Established by DOE in October 2023 (ARCHES, 2023a), this is a new entity charged with promoting hydrogen use. ARCHES suggests that hydrogen demand in California will be dominated by transportation: in 2045, it projects that 71.4 percent of hydrogen will be used for transportation, ports, and the maritime sector, with 23 percent used for power and the remaining 5.6 percent for industry (ARCHES, 2023b).

While there are a few highly optimistic studies (DOE, 2023a), taken together, most future outlooks agree that the majority of hydrogen will likely be used in transportation, industrial or manufacturing use, synfuel production, and ammonia production. That is, the share of hydrogen used for the electricity grid is predicted to be small by 2050 (2–19 percent when including studies from 2020, and 1.2 percent when considering more recent studies only). Given that these other demands for hydrogen eclipse the demand for hydrogen use on the electricity grid, it may be of interest to briefly consider the other demands for hydrogen that will affect prices. Here the authors provide a short description for the subset that (per the ARCHES study) are likely to be applicable to California: transportation and industry. They also briefly consider ammonia fertilizer due to California's large amount of agricultural land.

Transportation

The projections summarized above agree: now, and by 2045, the transportation sector represents the majority of demand for hydrogen; thus in 2045 (this report's focus timeframe), the transportation sector will continue to provide the majority of demand. Global forecasts suggest 23–55 percent of the world's overall use of hydrogen will be for transportation; ARCHES suggests as much as 71.4 percent (for transportation, ports, and maritime). There are many types of transportation where it is not feasible to decarbonize via electrification, and thus alternative carbon-free fuels such as hydrogen come into play. Studies show hydrogen can be used to replace fossil fuels in combustion engines (Acar and Dincer, 2020), such as in heavy-duty trucks (Cunanan et al., 2021). Given this, it is possible that in the future there will be hydrogen-fueled trucks (especially medium- or heavy-duty trucks) or other vehicles. Indeed, the U.S. Department of Energy is already supporting work into these vehicles; for example, General Motors received funding from DOE's SuperTruck program to create a fleet of medium-duty hydrogen-powered trucks (Hawkins, 2024).

Beyond trucking, it may also be possible to use hydrogen for other forms of transportation; more optimistic studies suggest hydrogen to be used by marine vessels (Sürer and Arat, 2022; Ustolin, Campari, and Taccani, 2022) or aircraft (Adler and Martins, 2023; Yusaf et al., 2024). Whereas there is some discussion about synthetic aircraft fuels (Air Products, 2022; Pavlenko and Mukhopadhaya, 2023), this is not likely to occur any time soon.

Industry

The next largest demand for hydrogen is predicted to come from industry or manufacturing. This includes, but is not limited to, oil refining, methanol production, steel production, petroleum refining, fertilizer production, and hydrocracking for petroleum products (IEA, 2024-d). In one study looking into potential hydrogen futures, the DOE suggests by 2050 the H2 market size with full adoption could encompass \$20–\$40 billion annually for steel, \$6–\$14 billion annually for chemicals such as methanol, and \$5–\$12 billion annually for ammonia (unclear if this includes fertilizer ammonia) (DOE, 2023a).

Ammonia Fertilizer

Ammonia fertilizer production is sometimes considered separately from industry measurement. Hydrogen can be used to create ammonia fertilizer (Galip, 2023), which has been flagged by U.S. Department of Energy as a possible pathway for clean hydrogen in other areas (DOE, 2023a). California has a lot of agricultural land, and thus might provide a market for ammonia fertilizer. In addition, ARCHES has suggested that agriculture, and related biomass waste gasification, can be used to produce hydrogen (Gilani, Humiston, and Chen, 2024).

Technologies Not Modeled

Fuel Cells

Hydrogen fuel cells (FC) generate electricity through electrochemical reactions, not combustion, of hydrogen and oxygen. The net reaction produces electric power, water, and heat. Unlike traditional power sources, FCs operate quietly and emit only water vapor as waste. Stationary FCs are designed to provide on-site power, typically for backup power or grid support. Stationary applications require durability, high efficiency, and reliability. In contrast, mobility FCs power vehicles which require compact, lightweight, and dynamic power output to handle changing speeds and loads. They prioritize flexibility, rapid startup, and adaptability for different types of usage scenarios in motion and these FC systems are designed with important fundamental differences versus stationary FCs. The vast majority of fuel cell investment today is focused on PEM mobility fuel cells (Papageorgopoulos, 2024; Satyapal, 2024; U.S. Department of Energy, undated-c).

Stationary fuel cells are options for niche applications but are not meaningfully pursued for utility-scale power generation today. One pilot example is the Calistoga Resilience Center (customer: PG&E) which has broken ground on a FC microgrid, but the advertised specifications do not contend with other utility-scale options (CEC, undated-f). Indeed, this microgrid was designed and deployed to replace a diesel generator and provide zero-emissions black-start capability (resiliency) for local town; it is not built to supply utility-scale power. Black-start pricing will likely be determined by the value of avoided downtime, not the cost of black start. The largest modern FC plant was specified at 79-MW in South Korea, but it is fueled by fossil gas and would therefore not be SB 100-compliant (Hydrogen Central, undated). Commissioned at a cost of \$240M, this plant equates to ~\$3,000/kW; more capital intensive on a per kW basis than turbines, batteries, and PV. RAND met with a fuel cell OEM who did not provide a specific capital cost but agreed that FCs are most appropriate for backup power applications, not utility-scale wholesale generation. In 2020, the Energy

Information Administration commissioned Sargent & Lundy to cost various electric generation technologies. They estimated $6,469/kW for fuel cells compared to $1,084/kW for an H-class, combined cycle gas turbine (both in 2020 USD) (EIA, 2020). In 2024, they updated cost estimates, but did not include a fuel cell (EIA, 2024a).

Liquid Alkaline Electrolyzer

Liquid alkaline water electrolyzers (LA-WE) are commercially mature and have been deployed for decades. Today's LA-WEs feature slightly cheaper CAPEX versus PEM-WEs but cannot match PEM-WEs in efficiency and production rate or the ramping capability needed to pair with California's renewables (Carmo, Fritz, and Mergel, 2013; Poindexter, 2022; U.S. Department of Energy, 2022-a). New materials and designs are currently in research and development but improvements along one dimension (for example, cell current density which underpins hydrogen production rate) may bring along the tradeoff of, for example, lower durability. These projects remain at low-TRL research and development and therefore likely would not be prepared for commercial deployment within ten or even twenty years (Revers, 2022; U.S. Department of Energy, undated-d).

Solid-Oxide Electrolysis Cell Electrolyzer

Solid-oxide electrolysis cells (SOECs or electrolyzers) remain precommercial today. This type of electrolyzer will not be able to ramp to pair with intermittent renewable generation (Tucker et al., 2018). Durability challenges plague these designs due to the requirement to operate at elevated temperature (550-850°C) which requires a continuous source of high-temperature heat (Tucker et al., 2018). SOECs are typically reported to pair best with nuclear reactors which generate substantial waste heat at moderate-to-high temperature (Koleva, Azubike, and Rustagi, 2020; Peterson and Miller, 2016).

Alkaline Exchange Membrane Electrolyzer

Alkaline exchange membrane (AEM) electrolyzers avoid expensive catalysts and potentially provide the dynamic response to fit California's needs. However, this electrolyzer variant remains at laboratory scale principally due to durability challenges with the anion-exchange polymers and membranes that comprise the electrochemical cell (James et al., 2022; U.S. Department of Energy, 2023a). Due to low TRL, a neutral stakeholder verified performance and cost figures could not be obtained and therefore, AEM electrolyzers were not modeled in this report. DOE, SBIR, and/or private venture capital should continue to invest in anion-exchange polymer chemistry development. If an appreciably durable anion membrane can be proven at the laboratory scale, EPIC could consider funding or co-funding a pilot-scale system.

Redox-Flow Battery

Literature review determined that only vanadium redox flow batteries (VRFB) are offered commercially today (Invinity Energy Systems, undated; Sumitomo Electric, undated; ThorionEnergy, undated), but none of these present a meaningful competitive advantage over LIB for California's utility-scale energy storage needs. PNNL estimates that compared with LFP batteries, VRFBs are less efficient, more capital intensive on both power and energy bases, more expensive in terms of fixed maintenance and decommissioning/recycling, and likely to degrade faster (although, possibly lower cycling degradation versus LFP) (PNNL, undated-b;

PNNL, undated-c). Another study found that although VRFB appears to be the most capable type of redox flow battery, and its performance comes close to LFP performance, VRFB performance does not exceed LFP performance and the levelized cost of storage remains higher than LFP (Darling, 2022). Moreover, VRB are potentially lower than TRL 9 today.

Commercial products offered today provide less than 24-hour discharge duration (Invinity Energy Systems, 2023) and in practice, it is not clear that electrolyte tanks can scale to arbitrary size. The VFRB electrolyte safety data sheet (SDS) from one original equipment manufacturer lists challenges to human health, nonhuman health, and the environment (Stryten Energy LLC, 2022).

It is plausible that some minor niches exist for VRFBs. For example, aqueous VRFBs may fundamentally pose lower risk of fire. Eliminating fire risk could be deemed so important in some applications that owners choose to internalize the VRFB premium for specific energy storage needs at specialized facilities. Although beyond the scope of this report, VRFBs may later encounter competition from solid state batteries and these two should be compared in a future study. Nevertheless, VRFBs do not appear to compete meaningfully with hydrogen for utility-scale seasonal energy storage.

NMC Li-Ion Battery

PNNL systematically investigated the cost differences between NMC and LFP batteries, citing NMC as significantly more expensive (PNNL, undated-b). Due to performance and cost differences, multiple industry leaders have observed the steady turnover from NMC to LFP for grid- and stationary-energy storage and power applications (Catsaros, 2023; Volta Foundation, 2023). One stakeholder commented that while most of today's installed systems are NMC, announced and emerging LIB systems are and will be overwhelmingly of the LFP variety. The LFP Li-ion Battery section compared numerous aspects of LFP to NMC LIB; LFP are cheaper and perform as well or better for stationary-energy storage applications.

Sodium-Ion Battery

Compared to sodium-ion batteries (Na-ion batteries, NIB), LFP batteries are cheaper, more durable, and commercially available today and are forecasted to remain so until at least 2030, and possibly beyond (DOE, 2024a). With a significant engineering breakthrough in cell cycle life and/or cost, NIB may become a premier candidate for utility-scale energy storage. However, experts suggest that there is not yet a line-of-sight for them to significantly outcompete LFP batteries (Spoerke, Durvasulu, and Balliet, 2023; Volta Foundation, 2023). Some reports claim potential for extraordinary NIB cost declines, for example, to as low as $10/kWh (cell cost) (Gordon, 2024), but a recent U.S. Department of Energy assessment found the power blocks are likely to remain approximately 30 percent more expensive than LFP through 2030 (Spoerke, Durvasulu, and Balliet, 2023). The U.S. DOE assessment included a wide literature review and discussions with OEMs (Spoerke, Durvasulu, and Balliet, 2023). NIB may avoid supply chain bottlenecks by using abundant, low-cost raw materials, but the cost advantage may decrease once the raw materials are processed and fabricated into battery subcomponents due to the need for complicated, advanced manufacturing processes.

Pumped Hydro Energy Storage

California will need to deliver approximately 370 TWh per year in 2045. Pumped hydro energy storage is a high-efficiency energy storage technology and is therefore a potentially good storage option. However, its extent in California might amount to ~0.5 TWh so it will not likely supply a substantial fraction of demand (NREL, 2025b).

Compressed Air Energy Storage

There are few appropriate sites for compressed air energy storage (CAES) in California. This technology cannot scale up to meet a significant fraction of California's electric power needs in the SB 100 fully decarbonized system. Nevertheless, CAES is a cheap and proven technology. While there may be benefits to deploying CAES, it is not expected to be a solution for total decarbonization of California's electric power system.

Liquid Hydrogen Storage

Hydrogen cannot be liquefied and stored in liquid form for months to provision competitively priced seasonal shift electric power (Swanger and Fesmire, 2021).

Net-Zero Biofuels

California's renewable portfolio eligible resource list specifies zero carbon, not net-zero carbon (CEC, 2021). This implies that net-zero biofuels will be ineligible for conversion to electric power per CA SB 100. If California were to reverse the zero-carbon constraint and replace it with a net-zero mandate, net-zero biofuels may be of use to California's decarbonized electric power system.

In addition, biomass-derived H2 could be considered net-zero. However, this type of H2 production commonly introduces impurities which transportation and consumption technologies may be unable to effectively tolerate. If net-zero H2 is later permitted, this challenge would remain.

Blue Hydrogen

To produce "blue" hydrogen for subsequent combustion in a power plant, a carbon dioxide stream would be generated. As with net-zero biofuels, California's renewable portfolio eligible resource list specifies zero carbon (CEC, 2021). This implies that blue hydrogen will be ineligible for conversion to electric power per CA SB 100. If California were to relax the zero-carbon constraint and replace it with a net-zero mandate, net-zero biofuels may be of use to California's decarbonized electric power system.

Aboveground Tank Storage

The cost of aboveground tank storage is approximately an order of magnitude greater than that of underground storage (Abdin, 2024). The amount of hydrogen required to generate appreciable power for the electric grid makes the amount of required tank storage impractical. As an example, a 400 MW turbine with an efficiency of 50 percent will require ~24 tons of hydrogen per hour. Running even four hours per day would require 96 tons of hydrogen every day, equivalent to 37 of the largest industrial hydrogen tanks available (Cheng et al., 2024; Taylor-Wharton, undated).

Fixed Offshore Wind

AB 525 requires a strategic plan for offshore wind. California's coastal bathymetry is more conducive to floating offshore wind, therefore fixed offshore wind is not expected to play a significant role in the state's offshore wind development. As such, California has established a goal of 25 GW of floating offshore wind (CEC, 2023). Fixed offshore wind metrics are tabulated but are not anticipated to be used for California and will not be modeled in subsequent phases of this project.

Table A.9: Offshore wind, fixed bottom

Metric	2024	2045	Unit	Range 2024	Range 2045
Overnight Capital Cost, Sens et al.	3,737		$/kW	(range 2,281-3379)	Range 1863-3103
Overnight Capital Cost, NREL ATB	5,990	3,209	$/kW		
Overnight Capital Cost, Sargent & Lundy, 900 MW plant	4,504	N/A	$/kW		
Overnight Capital Cost, RAND			$/kW		
Overnight Capital Cost, RAND modeling (high bound, if needed)			$/kW		
Overnight Capital Cost, RAND modeling (low bound, if needed)			$/kW		
OPEX, fixed, Sens et al.	93	63	$/kW-year		47 - 78
OPEX, fixed, NREL ATB	85	71	$/kW-year		
OPEX, fixed, Sargent & Lundy, 900 MW plant	188	N/A	$/kW-year		
OPEX, fixed, RAND modeling			$/kW-year		
OPEX, variable			$/kW-year		
Forward Learning Rate					

EIA. "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies" January 2024. Accessed November 4, 2024: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

Note: Sens et al. values are converted from Euro 20202 to USD 2024. Sargent & Lundy values are converted from USD2023 to USD2024 with the location adjustment for Los Angeles, California.

Sources: Sens, Lucas, Ulf Neuling, and Martin Kaltschmitt. "Capital expenditure and levelized cost of electricity of photovoltaic plants and wind turbines–Development by 2050." *Renewable Energy* 185 (2022): 525-537.NREL, "Offshore Wind", website, July 19, 2024. Accessed November 4, 2024.

ENERGY RESEARCH AND DEVELOPMENT DIVISION

APPENDIX B: Method for Estimating LCOE and LCOH

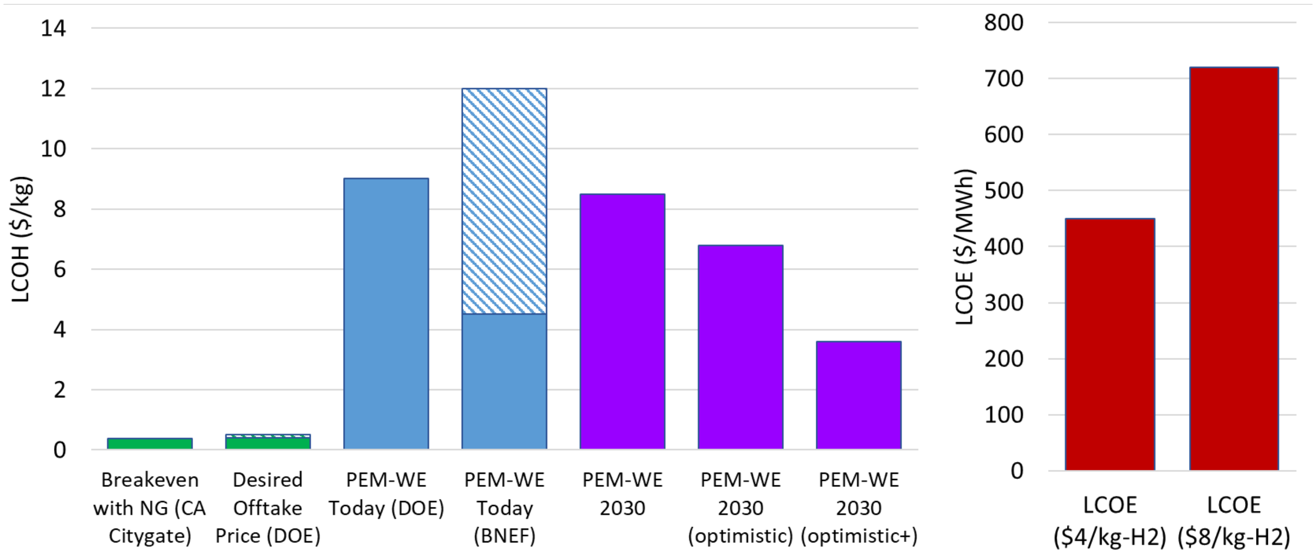
June 2026 | CEC-500-2026-018

Appendix B: Method for Estimating LCOE and LCOH

To benchmark hydrogen costs as a fuel for power generation and the resultant electricity generation cost, the authors estimate the levelized cost of hydrogen (LCOH) and levelized cost of electricity (LCOE) (Figure B.1). LCOH was determined using Electric Hydrogen's open-source project calculator (Electric Hydrogen, undated). California-representative costs of input electricity, CAPEX, and fixed operations & maintenance (O&M) costs were selected to estimate and bound LCOH for optimistic, baseline, and pessimistic scenarios. LCOE was calculated using the formulae published in NREL's 2024 ATB (NREL, 2024-b) assuming costs for a fossil gas combined cycle facility (EIA, 2024a) with the cost of parts adjusted (doubled) for burning hydrogen fuel, as was recommended by a turbine supplier.

Scenarios for LCOH were developed through a review of industry sources and were compared to ensure reasonable agreement with NREL's H2A-Lite model (NREL, 2025a). The optimistic+ scenario assumes a 25 percent CAPEX decline in PV and 55 percent CAPEX decline for electrolyzers which results in an LCOH just below $4/kg. The baseline estimate was just above $8/kg. The optimistic scenario adopted ambitious $900/kW CAPEX targets (Electric Hydrogen, 2022) which are far below DOE's optimistic assessment of ~$1,500/kW and the assessed cost of today's technology at ~$2,000/kW (DOE, 2024c). More conservative scenarios resulted in LCOH around $7/kg to $8/kg. LCOE from hydrogen combustion strongly depends on fuel cost and efficiency assumptions. As capacity factor (productivity as a fraction of nameplate capacity) and expected useful life decrease, CAPEX cost becomes more influential. A hydrogen combined cycle power plant sourcing fuel at these hydrogen costs would generate an LCOE of $450/MWh to $720/MWh. At the long-run target price of $1/kg hydrogen and aggressive CAPEX and O&M assumptions, LCOE could reach $70/MWh. For context, the EIA estimates LCOE for a new fossil gas combined cycle facility entering service in 2030 at $65/MWh (EIA, 2025a). For fuel cost to breakeven with fossil gas (California Citygate) on an energy basis, the LCOH would have to decline to ~$0.37/kg (EIA, 2025b). The U.S. Department of Energy surveyed industry and found stakeholders would be willing to pay $0.40/kg to $0.50/kg to burn hydrogen for power production (DOE, 2025-c). Bloomberg New Energy Finance estimated today's LCOH between $4/kg and $12/kg (Bhashyam, 2023).

Figure B.1: LCOH and LCOE



Note: hatched bars indicate the range of uncertainty.

Source: RAND Analysis.

ENERGY RESEARCH AND DEVELOPMENT DIVISION

APPENDIX C: Modeling Details

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Appendix C: Modeling Details

Diurnal Model

Parameterizing data

System resources were sized to meet the 2045 load forecast developed by the CEC's Integrated Energy Policy Report (IEPR) (CEC, 2025). California Public Resources Code section 25301 requires the commission to "conduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices." (California Public Law, 2019). The commission synthesizes detailed forecasts, resource plans, market assessments, and customer usage and billing data from utilities, suppliers, and other market participants, along with other pertinent factors including climate change, behind-the-meter PV & storage, heat pumps, energy efficiency, EVs (LDV, MDV, HDV). The resultant demand forecast is referred to as "2045 load" and "2045 demand" (interchangeably) throughout this report. A challenging day in the summer of 2045 was chosen for the load to supply.

Modeling Approach

- The PV capacity and battery capacity are sized (minimized) such that they meet the constraints of serving load on every hour of the day.
- Energy balance is enforced; the battery starts and ends with equal energy across the day.
- The peak battery C-rate was 0.13 indicating that the least-cost system is not power-limited. The PV Capacity Factor on the modeled day was 31 percent, above the annual average, indicating favorable conditions for renewables.
- For the model utilizing hydrogen, hydrogen production was minimized again subject to the constraint of sufficient generation to meet final demand (load). The electrolyzer capacity was also minimized to generate only the amount of hydrogen consumed given the PV generation profile of the day.
- The model parameters used for the key resources are provided in Table C.1.

Table C.1: Hydrogen Model Parameters

Parameter	Value
H2 Power Plant Net Nameplate Capacity (MW-e, pure H2 1x1x1 CC)	640
H2 Power Plant Net Efficiency (percent)	60
H2 LHV (MJ/kg)	120
System Average Transmission Line Loss (percent)	5
BESS Net Efficiency, one-way (percent)	93
BESS OCC ($/kWh)	436

Parameter	Value
BESS O&M fixed ($/kW/y)	40
BESS O&M var ($/MWh)	0
PV OCC ($/kW)	1,502
PV O&M fixed ($/kW/y)	38.39
PV O&M var ($/MWh)	0
H2 Turbine OCC ($/kW)	1,429
H2 Turbine O&M fixed ($/kW/y)	40
H2 Turbine O&M var ($/MWh)	0
PEM-WE Net System Specific Electricity Consumption (kWh/kg-H2)	57.5
PEM-WE OCC ($/kW)	2,000
PEM-WE O&M fixed ($/kW/y)	270
PEM-WE O&M var ($/MWh)	0
H2 Cavern OCC ($/kg)	16.665
H2 Cavern O&M ($/kg/y)	0.02
H2 Underground Size, 40 percent vol. cushion gas (kg)	693,333
H2 Storage Injection & Withdrawal Efficiency (percent)	87
H2 Pipe OCC ($/mile)	1,700,000
H2 Pipe O&M ($/mile-y)	10,000
H2 Pipeline Length (miles)	100
H2 Pipeline Loss, Pumping & Leak (percent)	2
Capital Recovery Factor (BESS, PEM-WE)	8.7 percent
Capital Recovery Factor (PV)	6.9 percent
Capital Recovery Factor (H2 cavern)	6.0 percent
Capital Recovery Factor (wind, hydro, H2 turbine, geothermal, pipeline)	7.0 percent

Source: Synthesis of Appendix A technology performance and cost tables

Seasonal Model

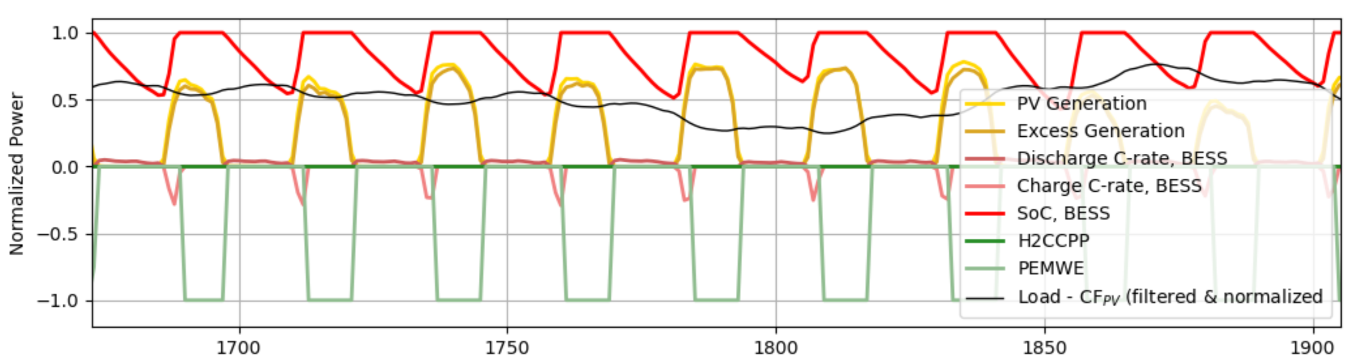
The seasonal models are similar in kind to the diurnal models, but with additional complexity. Examples of the seasonal hydrogen strategy dynamics are shown below. When possible, capacity factors for primary generation technologies were taken directly from empirical, 1-hour resolution data from California's generators. For solar PV capacity factors, the actual generation for each hour of the year was divided by nameplate capacity in that year to obtain capacity factor. These data were averaged over four years (2019–2022) to obtain the empirical solar PV capacity factor used in all modeling. The same procedure was applied for onshore wind. Geothermal operates with high stability, like baseload, and a constant 90 percent capacity factor was assumed. Large and small hydro power exhibit large variation from year-to-year. From 2012 to 2023, the capacity factor of large hydro varied from 10.8 percent to 34.3 percent. Similarly, small hydro varied from 15.4 percent to 41.4 percent (View Office Apps, 2024). Adopting a conservative planning approach, as is taken by IRP planners (CPUC, undated-a), the analysis models a large hydro as a 10.8 percent capacity factor with 10 percent random variation from day-to-day, and small hydro 15.4 percent capacity factor with 10 percent random variation from day-to-day.

The CARB scoping plan targets 21 GW of offshore wind. The team utilized six previously identified locations as prime sites for California offshore wind (Musial et al., 2016) and extracted 22-years of pertinent wind-speed data taken from National Offshore Wind-23 dataset corresponding to the six sites (Bodini et al., 2020; Wind Resource Database, undated). For each site, the analysis uses a 140 m turbine height, water-to-hub, the anticipated turbine height corresponding to expected technology advances (U.S. Department of Energy, 2021-a) and that the turbines built there would be appropriately sized to operate at 50 percent net capacity factor, as is common with commercial systems (Musial et al., 2016).

To solve the least-cost resource allocation problem, a differential evolution algorithm was employed to identify optimal resource mixtures that minimize total system cost while satisfying operational constraints (Kumar, Oliva, and Suganthan, 2022; SciPy, 2008). A penalty method was incorporated into the objective function to ensure that load was met at all 8,760 hours of the year by assigning a monetary cost penalty for violating supply shortfall. To enhance the robustness and reproducibility of results, an internal mutation rate sensitivity analysis was conducted, evaluating performance across a range of mutation factors. This internal sensitivity study confirmed solution convergence and stability.

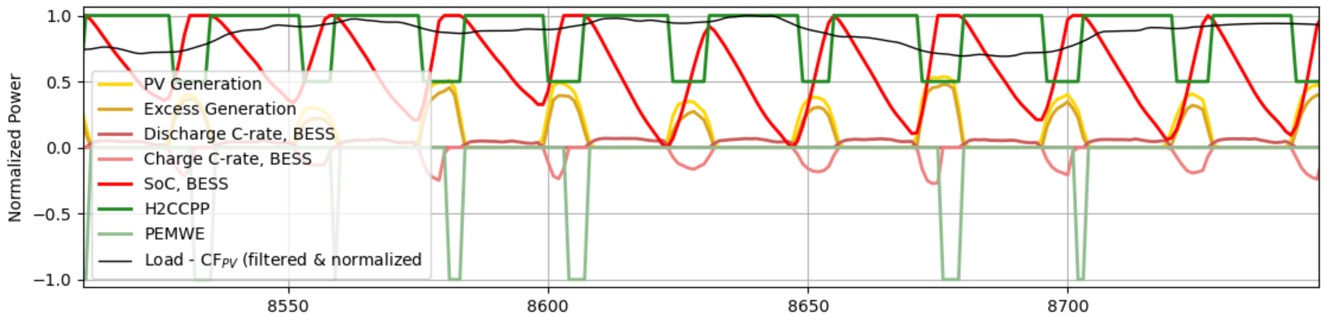
Examples of seasonal system dynamics are shown in Figures C.1 and C.2. Resources powers are normalized according to instantaneous power divided by rated power (nominal capacity). Battery normalization assumes a maximum C-rate of 1C. Negative battery power denotes charging. SoC is the aggregate battery state of charge. Excess generation refers to PV generation above that required to directly serve load. The hydrogen combined cycle power plant (H2CCPP) does not operate in Spring and Early Summer. The PEM-WE operates "greedily," occasionally turning on in Late Fall and Winter to scavenge any otherwise curtailed electricity.

Figure C.1: Spring and Early Summer



Source: RAND analysis

Figure C.2: Late Fall and Winter



Source: RAND analysis

Total System Annuitized Cost

For costing the electric power system with varying resource mixes, an annuitized cost framework was adopted. Annuitizing the total system cost is similar to "levelizing," that is, amortizing the cost of all the assets on the system, but simplifying financial parameters like debt-to-equity ratio to provide a more straightforward comparison with little loss of accuracy (NREL, 2024b, undated-a; PNNL, undated-d; Theis, 2021; EIA, 2015). Moreover, complicated financial details of future contracts cannot be known today, and the approach taken here is appropriate for establishing target resource mixes closer to California's 2045 goal. Annuitizing the total system cost further assumes that the grid will operate in perpetuity, and that sufficient assets comprise the system to average out or "smooth" new plant commissioning, retired plant decommissioning, depreciation schedules, and replacements on a rolling basis over a long-time horizon. Total system annuitized cost (TSAC) determines the cost before any incentives, policy, financing arrangements, or profits and avoids complex financial engineering to provide the best "apples-to-apples" comparison. Total system annuitized cost has units of present, nominal U.S. dollars per year and is defined below.

$$\text{TSAC} = \sum_{i=1}^{N} OCC_i \times CRF_i + OPEX_{fixed,i} + OPEX_{variable,i}$$

$$\approx \frac{1}{\tau}\int_0^{\tau} \left(\sum_{i=1}^{N} (Individual\ Asset\ Annual\ Amortized\ Cost)_i \right) dt$$

In accordance with best practice, the analysis presents cost data in terms of overnight capital cost (OCC), fixed operating cost (OPEX, fixed), variable operating cost (OPEX, variable), and capital recovery factors (CRF) (Bruckner et al., 2014; Theis, 2021). i indexes the sum over all system assets included in the given resource mix. τ is a representative duration of time considered long-enough to be near-enough the asymptotic value within reasonable accuracy. While many studies present "levelized" costs for individual technologies and systems, such values are necessarily dependent upon important operational choices such as capacity utilization and cycle times and intervals. Because these are exactly the types of choices explored in the modeling, the team opted to treat them as independent parameters and decouple them from costs. For hydrogen, the cost of hydrogen fuel is not directly priced; rather, the assets on the system that were needed to generate it (primary electricity generators, electrolyzers, hydrogen storage, and hydrogen pipeline) were costed, annuitized, and incorporated into the total system cost.

ENERGY RESEARCH AND DEVELOPMENT DIVISION

APPENDIX D: Environmental Impacts & Disadvantaged Communities

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Appendix D: Environmental Impacts & Disadvantaged Communities

Greenhouse Gas Emissions

Hydrogen has been proposed for use in the grid for its GHG reduction potential (CEC, 2022). Indeed, hydrogen combustion does not create sulfur oxides, CO_2, or CO emissions (National Academies of Sciences, Engineering, and Medicine, 2024). With EPA-regulated NOx controls, hydrogen can be included in an SB 100-compliant grid with negligible impact on GHG emissions.

Even though the Pathways model (Energy and Environmental Economics, Inc., undated) suggests certain types of hydrogen such as blue hydrogen are low-carbon alternatives and thus SB 100 compliant, there remains some uncertainty regarding the global warming impacts of incorporating hydrogen, however. For example, the National Academies writes: "Hydrogen is an indirect GHG with a 100-year global warming potential (GWP) estimated to be between 3 and 11" (compared to 1 for CO_2) (Field and Derwent, 2021; Paulot et al., 2021; Warwick et al., 2022). Hydrogen combustion is essentially complete, so the GHG emission potential from using hydrogen in the grid would stem from leaks occurring in the production, transportation, and storage stages. Hydrogen leaks are more difficult to prevent than fossil gas leaks because of the small size of the molecule (National Academies of Sciences, Engineering, and Medicine, 2024). However, escaped hydrogen gas is likely to be substantially less than escaped gas of today's fossil gas fleet due to downsizing of gas needs for the hydrogen seasonal storage. California's total fossil gas leaks (fugitive and vents) represent about 0.15 percent of gas throughput, and the majority of leaks arise downstream of compression, for example in residential distribution systems that hydrogen would not deploy (CPUC, undated-b; CPUC and CARB Joint Staff, 2024). An estimate for the project team's high-hydrogen-uptake seasonal storage concept would see approximately 600,000 metrics tons of hydrogen throughput per year which may translate to approximately 600 metrics tons of H_2 leaked per year. This would equate to 1,800–6,600 metrics tons in CO_2-equivalents or 0.0005–0.001 percent of California's GHG emissions (CARB, 2024).

Air Quality

The air quality impacts of adding hydrogen generation to the grid stem from hydrogen combustion. To assess the impact, the team evaluated the net effect of replacing a fossil gas turbine with a hydrogen turbine. Three relevant pollutants were considered: NOx, CO, and ammonia. The effect of replacing a fossil gas-fired turbine with a hydrogen-powered one on air-quality-related pollutants varies based on the technology of the old turbine and of the new turbine. In general, regardless of the technology, NOx emissions in natural-gas- or hydrogen-fueled turbines are controlled below emission standards using primarily three methods: 1) Water or steam injections that reduce the flame temperature and, therefore, reduce NOx concentrations, 2) Reactors that premix fuel (sometimes called dry, low-NOx combustion systems) to control the fuel-air ratio and the reactor temperatures, and 3) Selective catalytic reduction (SCR), which can be used in combination with either of the other two methods (Sargent & Lundy, 2022). SCR involves reacting NOx with ammonia; since ammonia is also an air pollutant, the final ammonia and NOx concentrations must be balanced to meet regulatory limits (Sargent & Lundy, 2022).

CO is another pollutant that is controlled by catalysts. Different turbine technologies perform differently under varying loads, and for many premixed reactors at low loads, CO emissions govern operating conditions (EPRI, 2022b). Since hydrogen-fueled turbines emit far less CO than fossil gas ones (because of the absence of carbon from the fuel), using a hydrogen fuel may extend the permissible range of a turbine (EPRI, 2022b). Note that the first method to control NOx can lead to an increase in CO emissions, especially in cofiring systems (Sargent & Lundy, 2022).

Using these methods, cofiring tests (mixing fossil gas and hydrogen) at plants with different pollution-control technologies suggest that emission regulations can continue to be met regardless of the pollution-control method or the specific turbine type: tests in New York up to 44 percent hydrogen by volume that used methods 1 and 3 to control NOx found they could remain below regulatory limits for all pollutants by increasing the water they injected (EPRI, 2022a); tests up to 25 percent hydrogen by volume at a plant in Upper Michigan that used methods 2 and 3 for NOx control could limit pollution levels below regulatory standards in the mixtures they tried by tuning the engine (EPRI, 2023); in Atlanta, a premixed combustion system maintained its compliance for all pollutants at hydrogen mixing ratios of about 20 percent by volume (EPRI, 2022b); and a premixed turbine (method 2) at an Alabama site controlled emissions up to 38 percent hydrogen by volume (Adams, 2023).

In theory, without emission controls, diffusion-controlled combustion systems (that is, where the fuel is not premixed) have hotter flames with hydrogen as the fuel than fossil gas does (EPRI, 2022b). This means that NOx production, which is highly sensitive to temperature, is greater in hydrogen systems compared to fossil gas ones when the flame temperature is not controlled (Lewis, 2021), though the CO concentration is zero since the fuel itself does not contribute to a carbon source (and lower in cofired systems) (Breer et al., 2023). Controlling this temperature with water injection may require more highly pure water than similar fossil gas systems. Or controlling the higher NOx emissions with ammonia (via method 3) may require higher emissions of ammonia or lower overall performance of the turbine.

The goal of premixed systems, in many cases, is to control flame temperature. At similar flame temperatures and other design parameters typical of turbine operating conditions, simulations indicate that premixed combustion systems likely produce less NOx than fossil gas ones when measured in terms of mass of NOx produced per energy input (Breer et al., 2023). This is because of the NOx-producing mechanisms that win out under different conditions.

Note that the flame speed of hydrogen combustion is more than nine times faster than fossil gas combustion, which increases the risk of a flame moving backwards into the fuel mixture it is combusting (EPRI, 2022b). This means that, historically and for low loads, many of the gas-to-hydrogen systems that have been tested are diffusion combustion systems (EPRI, 2022b).

However, the proposed hydrogen units at Scattergood Generating Station would use a premixed combustion system to control emissions in tandem with SCR (Rubin and Hauptman, 2023). It is therefore reasonable to assume that the new hydrogen-fueled units would not emit significantly more NOx than the historical units. Additionally, since the NOx levels prior to the SCR system are also not likely to be significantly elevated from current conditions assuming that the turbine parameters are sufficiently adjusted, it is unlikely that ammonia emissions would increase. Since hydrogen-fueled combustion naturally produces much less CO than natural-gas-fueled combustion, there is reason to expect a decrease in CO emissions at the site.

Water Consumption

The fundamental chemistry of hydrogen production requires water. The process of electrolysis consumes 9 liters of water per kg of hydrogen produced; however, additional water is required for water purification and for cooling. Out of all the varieties of hydrogen, electrolytic hydrogen is the most water efficient. Electrolytic hydrogen is produced using energy from renewable primary generators and can be made via alkaline or PEM electrolyzers. PEM-WE requires 25.7 liters (L) of water withdrawals and 17.5 L of consumptive use per kg of hydrogen produced while alkaline electrolysis withdraws 32.2 L and consumes 22.3 L of water per kg hydrogen produced (International Renewable Energy Agency, 2023). Withdrawals are volumes diverted from source for use and consumptive use is that which is not returned to the source. Most of the water withdrawn for hydrogen production is used for cooling (56 percent) while the remainder is used to clear mineral buildup in filters (blowdown water) and consumed for electrolysis (International Renewable Energy Agency, 2023). For comparison purposes, water withdrawn and consumed for two levels of annual electrolytic hydrogen production are reported as follows.

- Scenario 1
    - PEM-WE: 3,607 acre-feet (af) withdrawal/ 2,482 af consumptive
    - Alkaline electrolysis = 4,568 af withdrawal/ 3,162 af consumptive
- Scenario 2
    - PEM-WE: 20,835 af withdrawal/ 14,187 af consumptive
    - Alkaline electrolysis = 26,186 af withdrawal/ 18,079 af consumptive

Comparing this amount with other water uses within California, approximately 42.5 million acre-feet of water was withdrawn statewide in 2010 (USGS, undated). The 14,187 acre-feet of water consumed in Scenario 2 above amounts to 0.03 percent of California's total water consumption. It is instructive to compare this to the consumptive water use for thermal electricity consumption in California. Total electricity consumption in California in 2023 was 281,140 GWh, of which 42.1 percent, or 118,360 GWh was thermal (CEC, 2023a). Consumptive water use for thermal electricity generation in California (primarily fossil gas) is 0.05 gallons per kWh (a factor of 10 below the national average) (Torcellini, Long, and Judkoff, 2003), resulting in water consumption from thermal electricity generation amounting to 0.04 percent of California's total water consumption. As the electric grid decarbonizes, the amount of water consumed for power generation will decrease because solar PV and wind turbines do not require water for cooling. Thus, the addition of hydrogen production combined with the elimination of thermal electricity production will result in net water savings for the state. The location of hydrogen production facilities relative to retired thermal power plants may nonetheless require some local modification of water distribution capabilities.

Other Environmental Impacts of Hydrogen Production

The source of electricity used for green hydrogen is a large determinant in the total land area required for its production, with onshore and offshore wind turbines requiring approximately five times the land area per energy produced compared to solar PV. The SB 100 Core Scenario in 2045 projects that 1.4 million acres of land is required to fulfill new energy needs from renewable sources (CEC, 2024). The CEC has created a land use screening tool that adds geospatial layers to show areas of technical and economic barriers to building new renewable energy capacity in California (CEC, undated-b).

Hydrogen's Impacts on Disadvantaged Communities

Under the direction of SB 535, the CalEPA defines and identifies disadvantaged communities in order to target investments that would protect them (CalEPA, 2026). In 2017, CalEPA found that over 9.3 million people in California reside in disadvantaged communities (CalEPA, 2022; Rodriquez and Zeise, 2017).

Hydrogen deployed for seasonal energy storage and complementary decarbonization efforts can benefit disadvantaged communities by reducing exposure to carbon dioxide emissions, NOx emissions, particulate matter, and carbon monoxide. Regarding income, equity, and affordability, disadvantaged communities would enjoy the same statewide benefit of power system cost-minimization as all other ratepayers. However, an across-the-board cost reduction for ratepayers would disproportionately benefit disadvantaged people as they would keep a greater percentage of their disposable income.

California's greenhouse gas emissions in 2022 were 371.1 MMT CO2-e (CARB, 2024). 11 percent of these emissions were from the electric sector, which amounts to 40.8 MMT CO2-e (CARB, 2024). Decommissioning the CO2-e emitting fleet and replacing it with a hydrogen-fired fleet for seasonal energy storage would eliminate all 40.8 MMT CO2-e. Therefore, disadvantaged communities stand to benefit at a rate of approximately 4 metric tons of CO2 emissions eliminated per disadvantaged person per year.

Disadvantaged communities would also benefit from reduced exposure to criteria pollutants. EPA-recommended emission factors for stationary natural (fossil) gas-fired turbines are approximately 0.1 lb nitrogen oxides, 0.02 lb carbon monoxide, and 0.007 lb particulate matter per MMBtu of fuel burned (EPA, undated). These values can vary with the age of the turbine technology, cycle mode (simple or combined), and effluent controls such as a selective catalyst reduction unit (Andover Technology Partners, 2023; Air Quality Management District, 2023; Brewer et al., 2016; Eastern Research Group, 1998; England, 2004; EPA, 2025a). Replacing fossil gas-fired turbines with hydrogen for seasonal storage in SB 100 would benefit disadvantaged communities by lessening their exposure to these pollutants. Although the exact benefit to disadvantaged people depends on their unique distribution and density, their time-weighted proximity to power plants, and dynamic bulk wind patterns near power plants, previous research has found that half of fossil gas power plants are cited within disadvantaged communities; half of California's disadvantaged communities are directly exposed to fossil gas power plant emissions (Energy California, 2021). California's electric sector consumed 564,282 million cubic feet of fossil gas in 2024, equal to 5.85×108 MMBtu. At the EPA-recommended emission factors (pollutant generation rates), California's disadvantaged communities stand to benefit from the elimination of approximately 0.6 lb of carbon monoxide per disadvantaged person per year and 0.1 lb of particulate matter per disadvantaged person per year.

Hydrogen-fired gas turbines would still emit NOx, but the level would be controlled per legally binding EPA standards. Assuming EPA standards are not relaxed for hydrogen-fired turbines, disadvantaged communities would benefit the following calculations determine the potential benefit to disadvantaged communities.

For fossil gas:

5.85×10^{8} MMBtu * 0.1 lb. NOx/MMBtu * 50 percent cited within disadvantaged communities / 9.3 million people in disadvantaged communities

= 3 lb. NOx per disadvantaged person per year.

For hydrogen:

600,000 metric tons-H2 in the high-hydrogen seasonal storage scenario = 6.8×107 MMBtu. Assuming H2 plants become similarly cited within disadvantaged communities and that their emissions are controlled to the same effluent NOx concentration as fossil gas plants, the benefit would amount to

6.8×10^{7} MMBtu * 0.1 lb. NOx/MMBtu (controlled) * 50 percent cited within disadvantaged communities / 9.3 million people in disadvantaged communities

= 0.36 lb. NOx per person in disadvantaged communities per year.

Therefore, people in disadvantaged communities stand to reap benefit of up to 2.6 lb of NOx per disadvantaged person per year if California were to decommission fossil gas power plants and deploy hydrogen for seasonal storage. With more optimal siting and deployment of hydrogen power plants due to the much smaller number of H2 plants that will be required, the benefit could be as high as 3 lb.