# Integrating Hydrogen Production and Electricity Markets

## Analytical Insights from California

Omar José Guerra Fernández, Joshua Eichman, David J. Hurlbut, and Kaifeng Xu

*National Renewable Energy Laboratory*

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National Renewable Energy Laboratory
15013 Denver West Parkway
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# List of Acronyms

| | |
|---|---|
| CAISO | California Independent System Operator |
| CAPEX | capital expenditure |
| CF | capacity factor |
| DLAP | default load aggregation point |
| EIA | U.S. Energy Information Administration |
| EY | electrolyzer |
| GEN | generator power injection |
| LCFS | low-carbon fuel standard |
| LMP | locational marginal price |
| LSE | load-serving entity |
| OPEX | operating expenditure |
| PG&E | Pacific Gas & Electric Company |
| PPA | power purchase agreement (PPA) |
| PV | photovoltaic |
| reV | Renewable Energy Potential |
| RODeO | Revenue, Operation, and Device Optimization |
| RTP | real-time price |
| SCE | Southern California Edison |
| SD | standard deviation |
| SDG&E | San Diego Gas & Electric Company |
| SoCalGas | Southern California Gas |
| TOU | time of use |
| VRE | variable renewable energy |

# Executive Summary

This report compares the cost of different pathways for producing hydrogen in California. In addition to capturing the current cost of electrolyzers and other equipment, the pathways apply current retail electricity tariff options offered by utilities, including Southern California Edison (SCE), Pacific Gas & Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E). The analysis also tests the cost of combining hydrogen production with utility-scale wind or solar photovoltaic (PV) generation in California.

The cost benchmark—a relatively low electrolytic hydrogen breakeven cost— is based on the wholesale price of electricity used by a theoretical hydrogen production plant connected directly to the California Independent System Operator (CAISO) transmission system. California law currently prohibits this approach in CAISO, but it is permissible in other organized wholesale electricity markets. The cost for producing hydrogen under 2019 conditions in this theoretical case was approximately $3/kg. Different scenarios are used to examine current costs, e.g., 2019, as well as projections for 2030.

## Current Costs (2019)

Most costs for producing hydrogen are from the purchase of electricity. Costs using a standard retail service pathway depend on the utility where the electrolyzer plant was connected and on the availability of time-differentiated electricity charges. The least-cost case was $4.7/kg in SCE using the utility's real-time pricing (RTP) tariff. Costs for SCE's time-of-use (TOU) tariff were 23% higher. Generally, breakeven costs in PG&E or SDG&E were 53% to 71% higher than in SCE based on comparable tariffs.

The benefit of combining hydrogen production with utility-scale renewable generation is a function of both technology, e.g., wind versus solar PV, and location. In PG&E, where retail tariffs are expensive, hydrogen breakeven costs were reduced by half when the electrolyzer was combined with a wind plant in the PG&E territory compared to the demand response (retail market integration) pathway without onsite renewable generation. A hybrid plant with solar in PG&E reduced hydrogen breakeven costs by 15% compared to the demand response pathway without onsite renewable generation. In the SCE territory, combining an electrolyzer with wind increased hydrogen breakeven costs by 16%, and a combination with solar reduced hydrogen breakeven costs by 6% compared to demand response pathway without onsite renewable generation.

Figures ES-1 and ES-2 summarize the hydrogen breakeven cost for different system designs and integration pathways, including demand response and colocation (with 1 MW wind and solar PV facilities) pathways in 2019. The analysis includes both energy and demand charges based on either TOU or RTP tariffs.

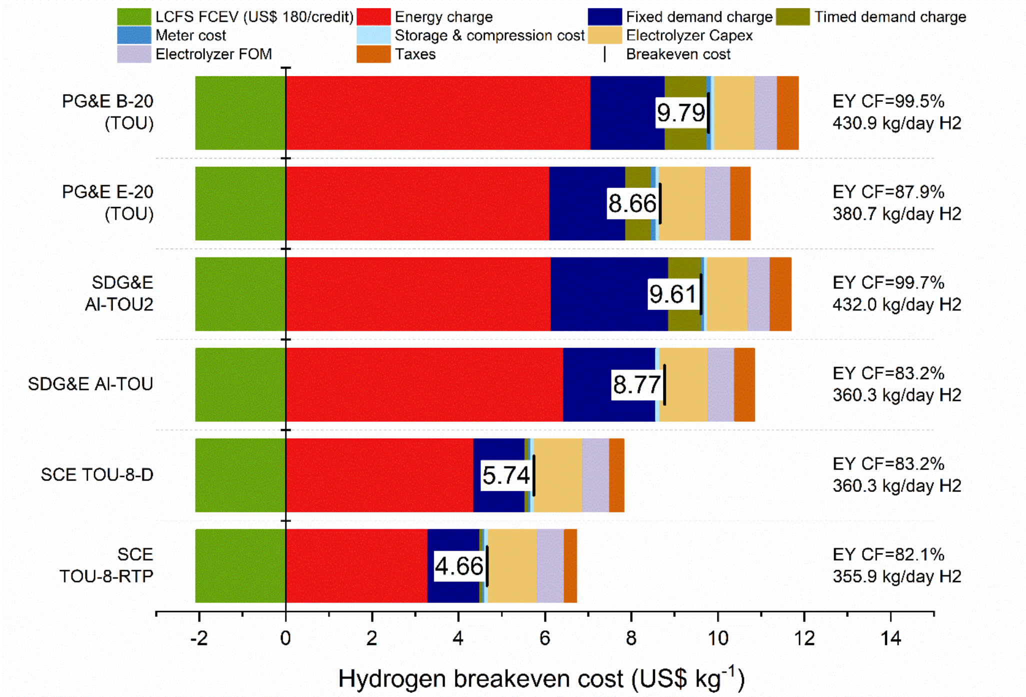


**Figure ES-1. Estimated 2019 hydrogen breakeven cost and optimal electrolyzer operation for the demand response pathway.** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 1 MW. See Section 4 for descriptions of utility tariffs.

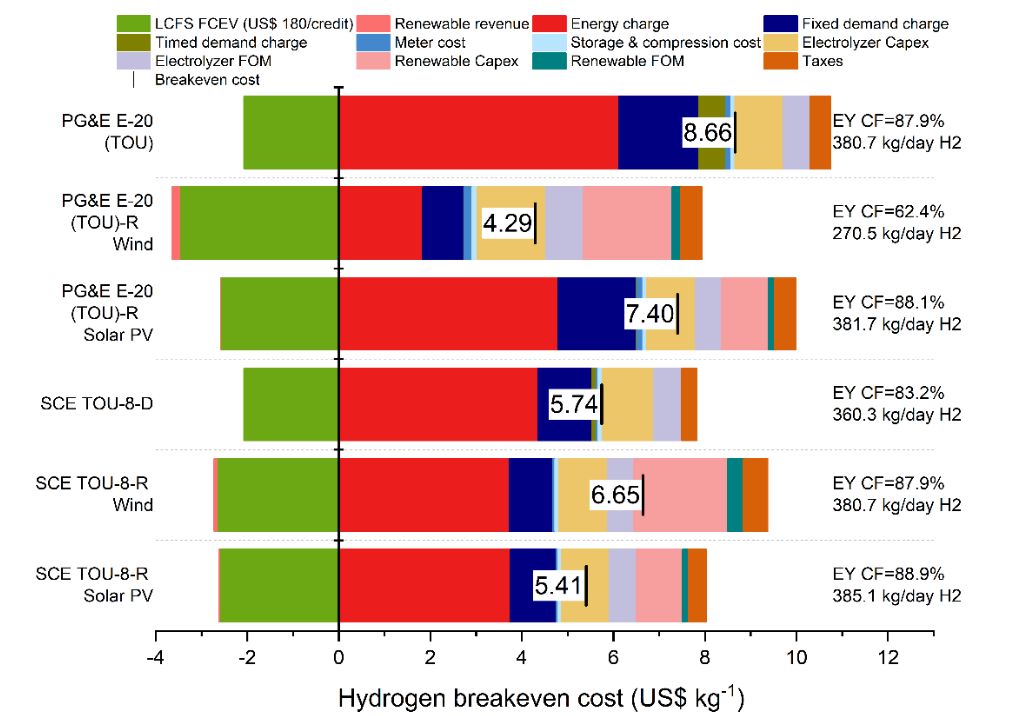


**Figure ES-2. Estimated 2019 hydrogen breakeven cost and optimal electrolyzer operation for colocation with 1 MW wind and 1 MW solar PV facilities.** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 1 MW.

## Projected Costs (2030)

Electrolyzer equipment trends suggest that costs could fall during the next 10 years. This study uses a midrange assumption of a 26% decrease by 2030 and a possible range from 17% to 41%.

The profitability of the retail service pathways still depends on the utility service territory. Inflation-adjusted breakeven costs in SCE fall by 5% in 2030 under the utility's RTP program and (with larger reductions in electrolyzer costs) fall as low as \$2.19/kg. Under a continuation of the utility's standard TOU program, breakeven costs could fall 2% by 2030.

Projected outcomes for PG&E and SDG&E were mixed. Hydrogen breakeven costs for 2030 fall 4% under the PG&E tariffs and increased slightly for SDG&E.

The simulations suggest that lower wind and solar costs could help hydrogen production under the hybrid pathways. In PG&E, 2030 costs were 22% lower for wind and 23% lower for solar. Costs in SCE fall 13% with an electrolyzer-wind combination and 15% combined with solar.

Figures ES-3 and ES-4 summarize the modeling results for retail market integration and colocation (with wind and solar PV) pathways in 2030.

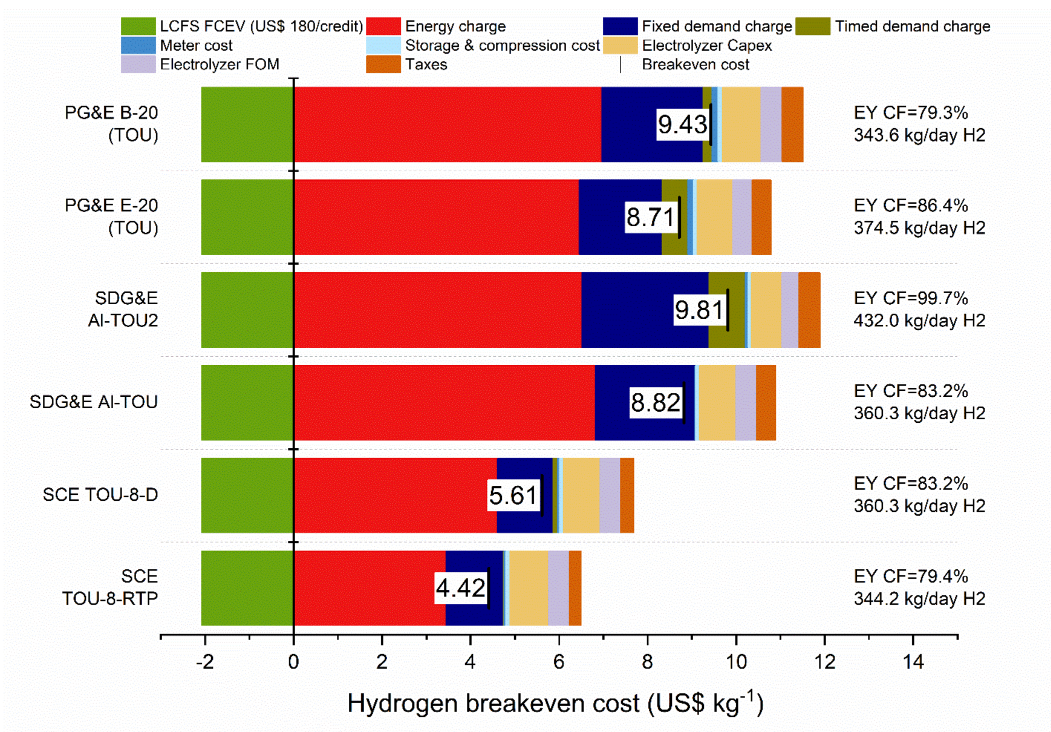


**Figure ES-3. Projected 2030 hydrogen breakeven cost and optimal electrolyzer operation for the demand response pathway.** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 1 MW.

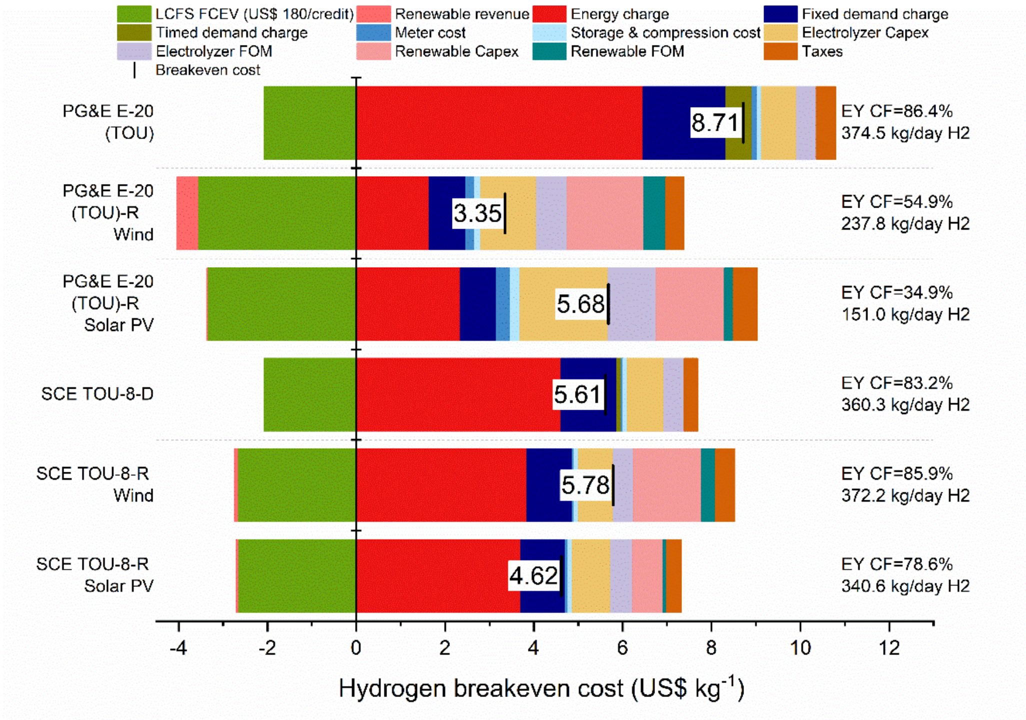


**Figure ES-4. Projected 2030 hydrogen breakeven cost and optimal electrolyzer operation for colocation with 1 MW wind and 1 MW solar PV facilities.** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 1 MW.

# Table of Contents

# List of Figures

# List of Tables

# 1 Introduction

Hydrogen is a flexible and potentially carbon-free energy carrier that could facilitate the integration of renewable energy sources across a variety of energy sectors, including the power (International Energy Agency 2019; O.J. Guerra et al. 2020; Omar J. Guerra 2021), industrial (Ruth et al. 2020), transportation (Dunn 2002; Omar J. Guerra et al. 2019; Stevens et al. 2017), and heating sectors (Staffell et al. 2018; Dodds et al. 2015), among others. Today, hydrogen is mostly produced via steam methane reforming using natural gas (International Energy Agency 2019); however, as the costs of hydrogen, wind power, and solar photovoltaic (PV) power technologies continue to fall, the production of electrolytic hydrogen is becoming more cost-effective. Electrolytic hydrogen production could become a cost-competitive alternative pathway in the near term, particularly for hard-to-decarbonize sectors, such as transportation, industrial production, and heating.

The cost of developing hydrogen transportation networks is a major challenge toward the use of renewable electrolytic hydrogen in these sectors. Blending hydrogen into natural gas transmission and distribution networks has emerged as an alternative cost-competitive option to transport electrolytic hydrogen across long distances for different end-use applications in the energy sector (Melaina, Penev, and Zuboy 2015; Cerniauskas et al. 2020; Ogden et al. 2018). There is also a need to better understand hydrogen breakeven cost as well as the integration of hydrogen production facilities with electricity markets.

Hydrogen can be produced via electrolysis using renewable electricity, electricity from the electric grid, or both (J. D. Eichman et al. 2020; Omar J. Guerra et al. 2019). Hydrogen production facilities can be integrated with both on-site renewable energy power plants and electricity markets (retail or wholesale) (J. D. Eichman et al. 2020). The siting of integrated hydrogen production facilities could be a critical factor in minimizing the required cost for hydrogen injection into the natural gas network.

This study explores the cost of different hydrogen production pathways with injection into the natural gas transmission networks of Southern California Gas (SoCalGas) and Pacific Gas and Electric Company (PG&E). First, the possible pathways for hydrogen production in California are identified and described in detail in Section 2. Then, in Section 3, a geospatial analysis base of the electric grid and natural gas stations is carried out to identify possible locations for electrolytic hydrogen production and on-site (or nearby) injection into the natural gas transmission network. After that, in Section 4, the modeling framework and techno-economic assumptions for different electrolytic hydrogen production pathways are presented. Next, in Section 5, a quantitative model-based analysis is performed to calculate the cost to produce hydrogen under different pathways, testing 2019 and 2030 timeframes. The quantitative analysis considers different revenue streams for hydrogen production facilities, including the sale of hydrogen, renewable electricity to the grid, and low-carbon fuel standard (LCFS) credits. The results represent the net cost of producing hydrogen with optimal operation of the electrolyzer. Finally, key insights from this study are summarized in Section 6.

# 2 Pathways to Hydrogen Production

The market integration pathways examined in this study represent various ways to reduce the cost of electricity in hydrogen production. Some pathways engage the integration with wholesale market directly, e.g., **direct wholesale market participation**, whereas retail market integration pathways take advantage of demand response programs offered by the distribution utility. Some pathways combine retail and wholesale elements.

If the electrolyzer connects to the distribution utility's system, participating in **demand response** can reduce the cost of electricity. Utilities that offer demand response programs give customers price incentives to modify their electricity use in ways that reduce the utility's cost of procuring wholesale power. Here, we consider two types of demand response: time-of-use (TOU) rates and real-time pricing (RTP).

Delivery costs constitute a large part of electricity's retail markup. If both the generation and use of electricity occur behind the same meter, the transaction does not need the delivery system and thus incurs no delivery costs. This defines one type of pathway: **colocation** of an electrolyzer and a generator. Some or all of the output from the power plant would flow directly to on-site hydrogen production without using the transmission or distribution system. Any supplemental power for producing hydrogen would come from the grid as retail service.

We also include two special pathways. In one, the hydrogen producer participates directly in the California Independent System Operator (CAISO) wholesale market. Although this is currently not possible in California, it is in other organized wholesale markets. The other special pathway involves the use of **federal hydropower** to supplement on-site generation, an option limited to entities with federal hydropower entitlements. This section will describe different pathways for the integration of electrolytic hydrogen production, electricity markets, and variable renewable generation, including these four pathways: **direct wholesale market participation**, **demand response**, **colocation**, and **federal hydropower**.

## 2.1 Conceptual Pathway: Direct Wholesale Market Participation in CAISO

We included one conceptual pathway that, though feasible in other organized wholesale markets, is essentially precluded in CAISO. We include it here to provide a benchmark comparison for other pathways. This pathway contemplates large-scale hydrogen production at a single location on the CAISO system (see Figure 1). The producer participates in the CAISO wholesale market directly by

- Establishing a self-dedicated load-serving entity (LSE)
- Building an electrolyzer at a point connected to the CAISO system
- Taking electric service from its dedicated LSE.

The hydrogen producer's LSE would register with a scheduling coordinator—the entities authorized to submit energy offers and load schedules into the CAISO markets. CAISO would include the hydrogen producer's scheduled load in its optimization, which would produce the LMPs that the producer's LSE would pay for the quantities of power it had scheduled. The LSE would also be obligated to pay a transmission access charge, which, as of August 12, 2020, was

$12.61 per MWh (California Independent System Operator 2020b). In this study, we assumed that the hydrogen producer and its LSE are affiliated with one another and that the transaction costs between them are minimal.

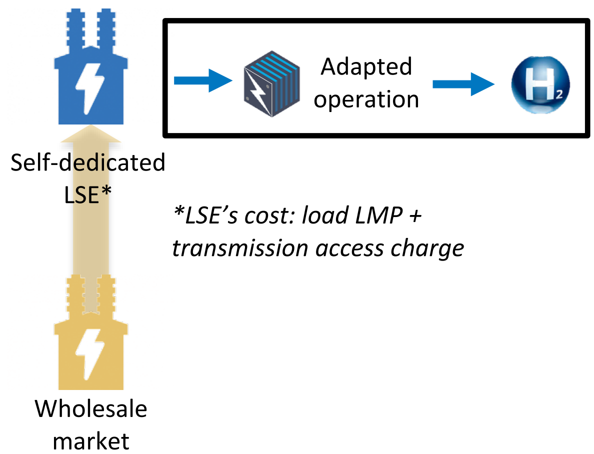


**Figure 1. Hydrogen production as a self-supply LSE.**

Although these steps comport generally with California laws and regulations, there is currently a cap on the amount of load that can be served by all nonutility LSEs on a distribution utility's network (California Public Utilities Commission (CPUC) 2010). All caps have been met, leaving no room for this pathway.

## 2.2 Demand Response Pathways

Demand response programs are retail tariffs that reduce the customer's bill based on strategically managed electricity use. Each demand response pathway is potentially applicable to service taken from any LSE: a distribution utility, community choice aggregator, direct-access retail service provider, municipally owned utility, or other multi-meter aggregation that serves retail load separated from the major utilities. Any retail arrangement includes transmission, distribution, and policy-related costs. The demand response pathways illustrated in Figure 2 assume that hydrogen production can be scheduled to take advantage of the discounts contained in the applicable tariff.

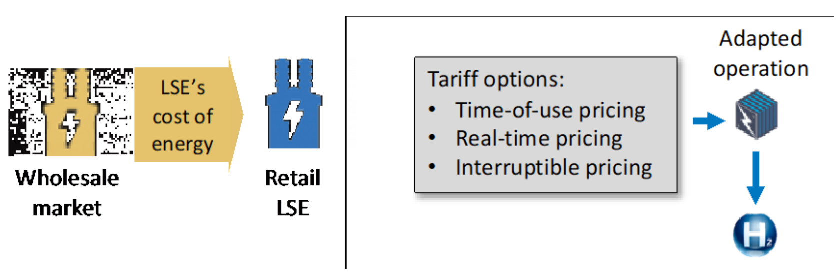


**Figure 2. Demand response pathways.** Time-of-use and real-time pricing options are evaluated in this study and described in detail below. Interruptible pricing was not included in this study.

### 2.2.1 Time-of-Use Pricing

*The electrolyzer runs at high capacity during low-priced time blocks and at low capacity during high-priced time blocks*. TOU time blocks are simple: seasonal peak and off-peak periods with fixed rates for each time block (Southern California Edison (SCE) 2021a). This makes variations in electricity costs predictable, allowing the retail customer to set monthly or annual schedules for hydrogen production at the most cost-effective times.

### 2.2.2 Real-Time Pricing

*The electrolyzer runs at high capacity during hours when energy prices are low and at low capacity during hours when energy prices are high; it curtails hydrogen production during critical peak hours.* RTP programs vary the energy component of retail service by hour. Increased time granularity provides the customer with more potential savings than under simple TOU pricing, but there is less predictability.

The energy component of an RTP tariff could directly follow settlement LMPs for load, but as of this time no utility has done so. Instead, Southern California Edison (SCE) uses a matrix of hourly prices based on seasons and workdays (Southern California Edison (SCE) 2021b). Some hourly prices might also vary based on the prevailing temperature: higher temperatures are correlated with higher demand, which is correlated with higher LMPs. SCE's matrix of energy prices generally reflects the same diurnal variations seen in LMPs from 2018 through 2019.[1]

Getting the full benefit of an RTP program requires more effort on the part of the customer. Energy prices are more dynamic than under a TOU program, so electrolyzer operation is more likely to involve day-ahead or same-day scheduling adjustments.

## 2.3 Colocation Pathways

*Colocation* refers to the direct pairing of a hydrogen production plant and an electric generator. To standardize the test scenarios used in this study, we assume that the hydrogen facility is located at an injection point on the natural gas pipeline system. If the electrolyzer and the power plant are geographically separated, the power line connecting them is considered part of the project's cost.

Power delivered from a generator directly to an electrolyzer is not subject to a tariff by the retail distribution utility. The terms under which the electrolyzer would buy power from the colocated generator would be negotiated and set in a bilateral power purchase agreement (PPA). We set aside the legal relationship between the electrolyzer and the generator for this analysis. Even if the two operations are owned by the same company, the underlying economics would be essentially the same as they would be under a two-party PPA. In both cases, the critical issue is the price point at which making hydrogen would be profitable. This price point depends on the same economic factors regardless of whether the generator and the electrolyzer are owned by the same company.

A major consideration for the generator is the locational marginal price (LMP)—the moment-by-moment wholesale prices it would receive for sending power to the grid. CAISO's day-ahead

[1] The relevant node for comparison is CAISO's default load aggregation point for SCE (DLAP_SCE-APND).

market produces point-specific LMPs for every hour of the next operating day. Real-time LMPs are calculated every 5 minutes and 15 minutes. Many points on the CAISO grid have LMPs that are low or occasionally negative several times during the day. Diverting output from the grid to hydrogen production at these times could reduce the generator's risk of operating at a loss.

Figure 3 illustrates the three colocation models: on-site generation dedicated entirely to hydrogen production, an electrolyzer supported entirely by a large utility-scale generator that is also selling to the CAISO market, and a hybrid of these two models (hybrid colocation). Of the three colocation pathways, only the hybrid pathway is simulated in this study. It offers the most flexibility and the greatest opportunity for cost reduction because of the joint optimization of hydrogen production and electricity delivery to the grid. The optimization model determines if the purchase or sale of electricity is preferred and responds accordingly. No retail electricity is purchased if it does not result in an optimal solution, and no output from the utility-scale generator is sold at a loss on the wholesale power market.

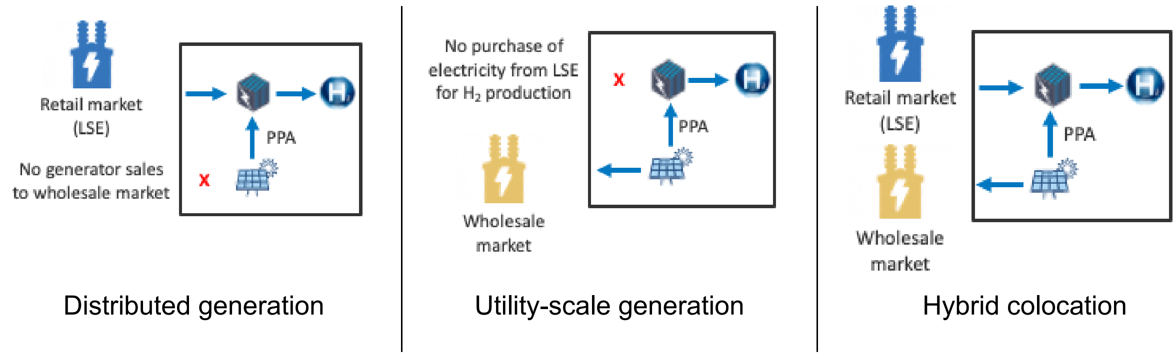


**Figure 3. Colocation pathways, disposition of electricity.**

The hybrid colocation pathway is described in more detail below.

### 2.3.1 Hybrid Colocation

*Hydrogen production uses both on-site generation and retail electricity service; the generator splits output between hydrogen production and market sales.* This pathway provides operational flexibility to both the generator and the hydrogen producer. It allows the electrolyzer to run at high capacity, using an optimal combination of retail electricity and power from the generator with which it is paired. The generator could hedge the risk of low LMPs by strategically reserving some of its output for the colocated electrolyzer.

The economic benefit of this pathway depends on the LMPs and on the cost of the colocated generation. Frequent occurrences of low or negative LMPs at the generator's node on the CAISO system could increase the room for a deal. PPA negotiations would seek a bilateral pricing scheme that is less than the retail electricity and yet high enough to provide the generator with an operating profit. The PPA's delivery provisions would address uncertainty about LMPs while accounting for all the generator's obligations to CAISO. For example, the PPA could specify a fixed delivery schedule based on LMP forecasts, or it might condition delivery on prevailing LMPs. In modeling this pathway for this study, we assumed perfect foreknowledge about LMPs. This captures the *maximum potential* value of this pathway, recognizing that the actual value could be less depending on how the counterparties manage uncertainty between them in the PPA.

## 2.4 Special Pathway: Federal Hydropower

This special pathway applies to a Native American tribe, municipality, or other entity with a contract for federal hydropower in the Western Area Power Administration (WAPA)'s Desert Southwest region, which overlaps the eastern portion of the SoCalGas pipeline system (see Figure 4). In this option, federal hydropower would round out the electricity requirement during hours when on-site generation is unavailable, resulting in more operating hours for the electrolyzer.

This is operationally similar to the pathway described above in Section 2.3.1, except that the supplemental retail supply would be federal hydropower. Currently, the energy cost of federal hydropower is less than 20% of CAISO's average energy prices for 2019 (California Independent System Operator 2020a; Western Area Power Administration (WAPA) 2021). The energy charge is fixed, so it can be used at any time without incurring a price penalty.

A unique factor for this option is that some tribes that have a statutory entitlement to federal hydropower lack transmission access to take physical delivery of it.[2] As a result, the study frames this option as a tribal enterprise (not necessarily located on the reservation) using some or all of its federal hydropower entitlement to produce hydrogen. The tribal enterprise would be on a host utility's delivery system near an injection point on the SoCalGas pipeline system.

This option could also apply to a municipally owned utility with a federal hydropower entitlement; however, physical delivery is seldom an issue for cities, and they generally include their allocations in their supply mix to serve customers. Consequently, diverting part of it to produce hydrogen would require replacing it with more expensive power. Cities also have less latitude than tribes in how they use their hydropower entitlement.

Regardless of the economic analysis in this study, the application of this pathway would be subject to laws governing the use of federal hydropower. We set aside the legal issues for this analysis on the assumption that they would be of interest only if this pathway proved economic.

[2] A 2017 reallocation of hydropower from the Boulder Canyon Project includes, among other allotments, 39 GWh per year to 13 California Native American tribes and authorities (Western Area Power Administration (WAPA) 2014).

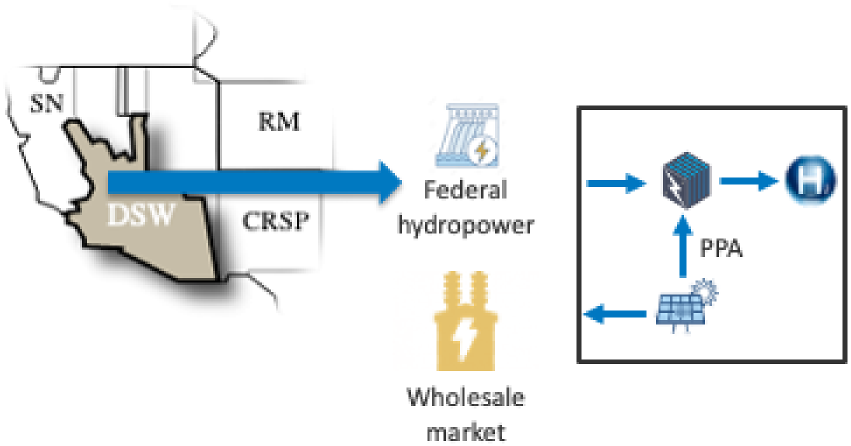


**Figure 4. Special pathway: federal hydropower.**

Finally, the input electricity prices applicable to each hydrogen production pathway are summarized in Table 1.

**Table 1. Pathways and Applicable Electricity Input Prices.**

| Pathway | | Description | Applicable Electricity Prices | Included in this study |
|---|---|---|---|---|
| Wholesale market integration (conceptual) | 1 | Self-supply LSE | LMP (load node) | ✓ (Conceptual pathway) |
| Demand response | 2 | TOU | Retail tariff (TOU) | ✓ |
| | 3 | RTP | Retail tariff (RTP) | ✓ |
| Colocation | 4 | Distributed generation, no export to grid | Retail tariff | |
| | 5 | Large utility-scale generation | LMP (generator node) | |
| | 6 | Hybrid | Retail tariff and LMP | ✓ |
| Special | 7 | Federal hydropower | Federal hydropower tariff | ✓ |

# 3 Geospatial Analysis for Hydrogen Injection

## 3.1 California Independent System Operator Electricity Network Nodes

A node is a price point on the CAISO grid. Most are either generator power injection points (GEN nodes) or points where power is taken off the grid to serve load (load nodes). More than 1,400 GEN nodes were active in 2019. Figure 5 illustrates the geographic distribution of annual average LMPs in 2019, ranging from \$25.22/MWh to \$59.69/MWh.

The price that CAISO pays a generator for power is the LMP of the generator's GEN node. Wholesale demand is charged the LMP at the corresponding load node. To simplify the settlement, load nodes common to one load-serving utility or other LSE are aggregated into a default load aggregation point (DLAP), a weighted average representing all load nodes in the utility's territory. A large utility area can be subdivided, and load nodes within a smaller region are aggregated into a sub-load aggregation point value. To simply the data analysis, this report uses three DLAP LMPs—PG&E, SCE, and SDG&E—to represent load node LMPs in the corresponding region.

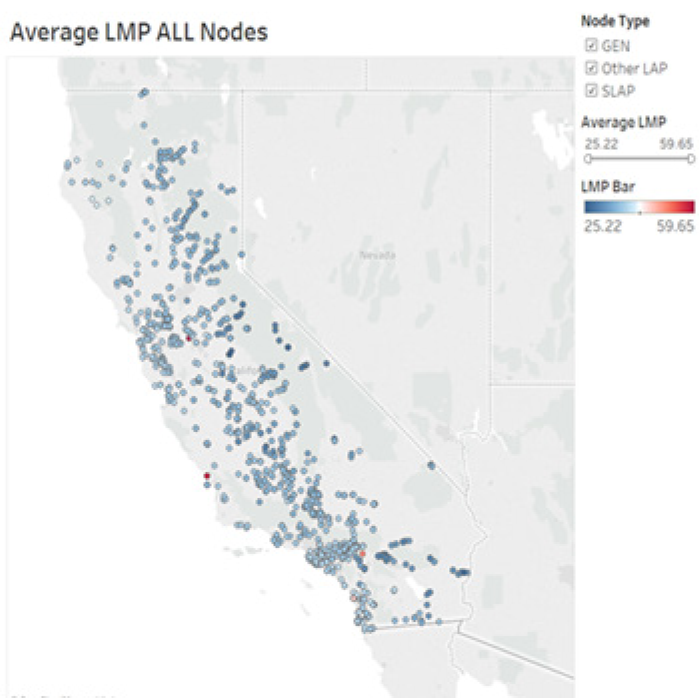


**Figure 5. Annual average LMP (\$/MWh) by node in 2019.**

## 3.2 Utility Gas Pipeline Stations

In this study we used gas station geospatial data from PG&E and SoCalGas to assess the potential locations for hydrogen injection into the natural gas network in California. There is a significant number of potential hydrogen injection points in both PG&E and SoCalGas natural gas pipeline systems. The colocation and direct purchasing pathways assume the shortest distance between the electrolyzer facility (located on the gas pipeline system) and the corresponding CAISO node. The following section describes the methodology used to identify these potential hydrogen injection locations based on the location of electric grid nodes and gas stations.

## 3.3 Geospatial Analysis for Hydrogen Injection Points

The distances between the hydrogen production site, electrical transmission network, and gas transmission network affects the amount of infrastructure that must be installed to connect the systems. In this study, we develop an indicative distance from a pipeline to the nearest transmission line based on a geospatial analysis of injection points on the SoCalGas and PG&E pipeline systems and the load nodes on the CAISO network. Injection points were selected based on the availability of local infrastructure (e.g., pressure stations) that represents potentially low-cost points of injection. This serves as test set of viable locations, recognizing that other points might be feasible. The distance was calculated based on the latitude and longitude of the CAISO price nodes and gas injection points.

### *3.3.1 Colocation Generator Power Injection Node Selection*

The colocation pathway enables electrolyzer access to electricity from solar and wind power plants. To minimize the transmission line cost, this study selected GEN nodes that have the shortest distance to the PG&E and SoCalGas injection points.

We calculated the distance for each GEN node (i) for wind and solar plants to the nearest gas injection point (k). The distance between two points ($D_{i,k}$) was calculated using the R geospatial tool DistGeo(Karney 2013a), which is based on algorithms developed by Karney (Karney 2013b). The selection of desired renewable GEN nodes is therefore based on the equation:

$$Min\left[D_{i,k}, D_{i,k+1}, D_{i,k+2} \dots \dots D_{i+1,k}, D_{i+1,k}, D_{i+2,k} \dots \dots\right]$$

In 2019, CAISO had more than 200 active solar nodes and 60 wind nodes. The analysis found that for the SoCalGas system, 25% of solar nodes are within 1.41 miles of an injection point, whereas 25% of wind nodes are within 3.13 miles. For the PG&E pipeline system, 25% of solar nodes are within 7.04 miles of an injection point, and 25% of wind nodes are within 5.18 miles. The analysis selected the four GEN nodes with the shortest distances to injection points (PG&E and SoCalGas each) for the breakeven cost studies described in Section 4. Figure 6 illustrates the screening process.

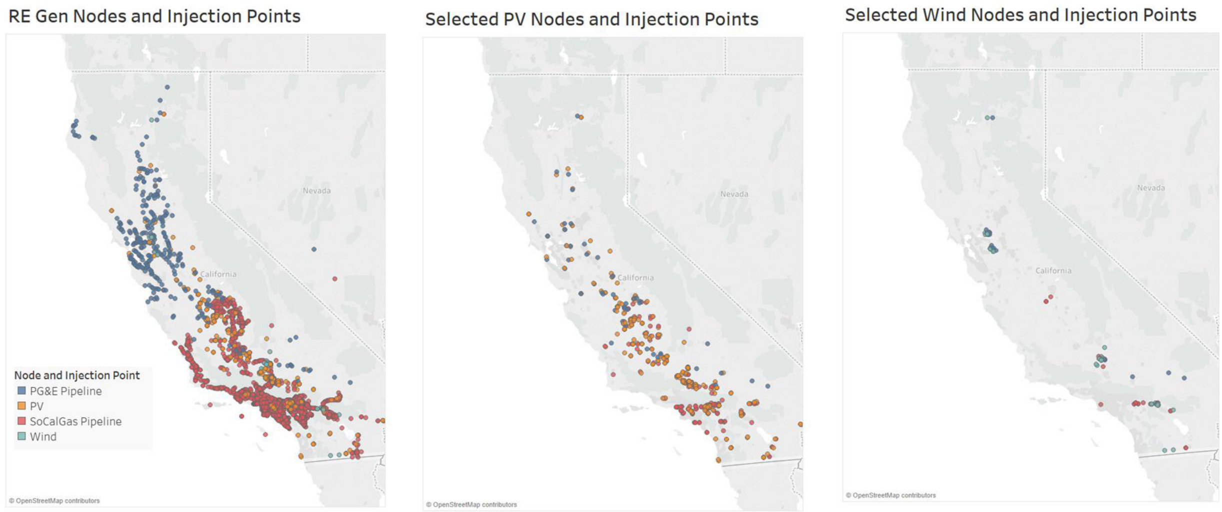


**Figure 6. Solar and wind GEN nodes and injection point locations.** Left panel: renewable generation nodes and natural gas or hydrogen injection points. Center panel: selected solar PV nodes and corresponding hydrogen injection points. Right panel: selected wind nodes and corresponding hydrogen injection points.

### 3.3.2 Load Node Geospatial Analysis

Unlike the colocation pathway, the DLAP LMPs in corresponding regions were selected to calculate the breakeven cost of the direct wholesale market participation pathway. The geospatial analysis tested the distance profiles of injection points on the SoCalGas and PG&E pipeline systems and the load nodes on the CAISO network.

Using the same geospatial calculation method, the analysis found that on the SoCalGas system, 93.11% of the injection points are within 10 miles of a load node; and on the PG&E system, 97.35% of the injection points are within 10 miles of a load node.

# 4 Modeling Framework and Techno-Economic Assumptions

## 4.1 RODeO Model

The Revenue, Operation, and Device Optimization (RODeO) model was used to calculate the minimum hydrogen breakeven cost—the ratio between net total expenditures (discounting incomes from LCFS credits and sales of renewable power to the grid) and total hydrogen production— for selected pathways based on the 2019 and 2030 timeframes using a 1-year optimization window with hourly resolution (8,760 time periods). The RODeO model explores optimal system design and operation considering different levels of grid integration, equipment cost, operating limitations, financing, and credits and incentives, as depicted in Figure 7.

RODeO is an open-source price-taker model formulated as a mixed-integer linear programming model in the GAMS modeling platform, and it is publicly available via GitHub.[3] The objective function is to maximize the net present value of the revenue for a collection of equipment at a given site. The equipment includes generators (gas turbine, steam turbine, solar PV, wind, hydro, fuel cells, etc.), storage systems (batteries, pumped hydro, gas-fired compressed air energy storage, long-duration systems, hydrogen), and flexible loads (electric vehicles, electrolyzers, flexible building loads). The input data required by RODeO can be classified into three categories:

1) utility service data, which refer to retail utility rate information (meter cost, energy, and demand charges).

2) electricity market data, which include energy and reserve prices.

3) other inputs, such as additional electrical demand, product output demand, technological assumptions, financial properties, and operational parameters.

[3] See https://github.com/NREL/RODeO.

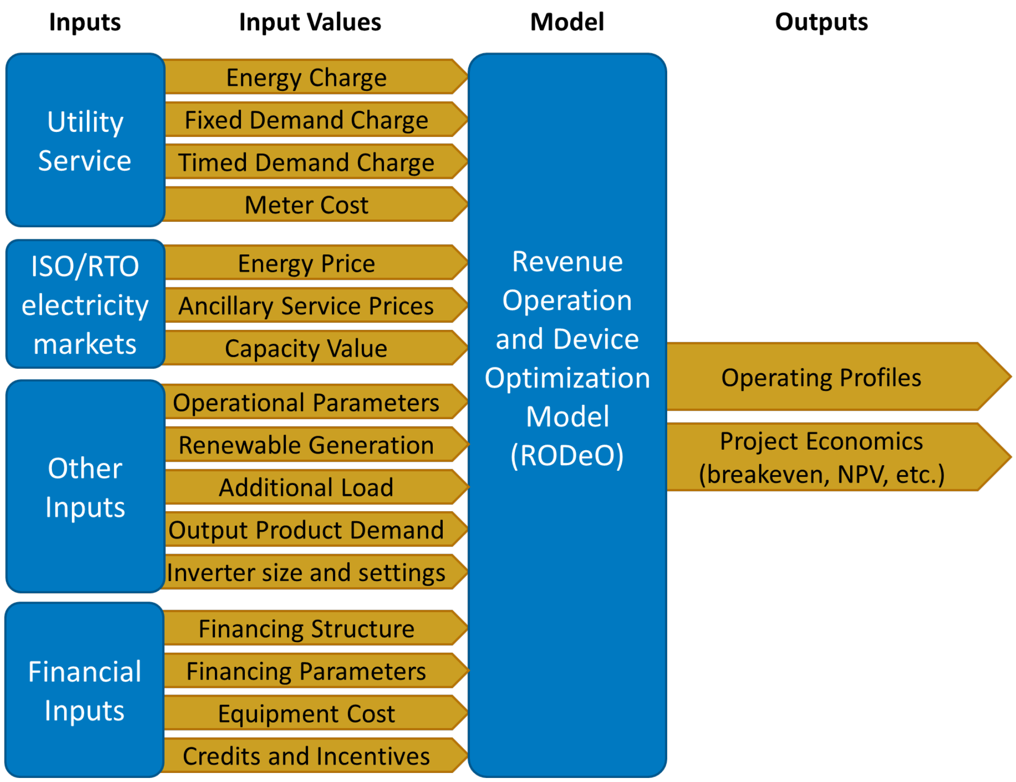


**Figure 7. RODeO workflow.**

## 4.2 Techno-Economic Assumptions

The techno-economic assumptions used in this analysis are described and summarized in the following sections.

### *4.2.1 Utility Rates and Locational Marginal Prices*

To test pathways that involve the integration of hydrogen production systems with the retail electricity market, we collected tariff information for California's three main utilities from the Utility Rate Database (URDB) (National Renewable Energy Laboratory 2017) and directly from the utilities' tariff books. The selected 2019 electric tariffs for each utility are described in Table 2. These tariffs include both energy and demand charges based on either TOU or RTP approaches.

**Table 2. Selected Tariffs for Each Utility Territory.**

| Utility | Tariff | Description |
|---|---|---|
| PG&E | B-20 | **Regular TOU**<br>Four time slices each day |
| | E-20 | **Peak-day pricing**<br>Utility declares a peak-day pricing event for the next day, and critical peak pricing takes effect from 2 p.m. to 6 p.m. Prices during an event are eight times higher than normal peak period rates. Rates for all other times are slightly less than regular TOU rates. |
| SDG&E | AI TOU | **TOU (energy weighted)**<br>Four time slices each day; per kWh charges are higher. |
| | AI TOU2 | **TOU (demand weighted)**<br>Four time slices each day; per kW and per-month charges are higher. |
| SCE | TOU-8-D | **Regular TOU**<br>Two time slices each day for summer, three time slices for winter days |
| | TOU-8-RTP | **RTP**<br>Different energy price for each hour of the day, with two or three tiers based on temperature. Critical peak pricing embedded from 5 p.m. to 7 p.m. on hot summer days (energy price is 23 times the price for moderate temperature days). |

Overall, retail tariffs for PG&E and SDG&E are higher than those for SCE. Other types of electric utilities—municipally owned utilities and irrigation districts—mostly have rates that are less than those of the investor-owned utilities. Table 3 shows the 2020 average rates for a larger selection of California utilities, with average rates ranging from 12 cents/kWh to 24 cents/kWh.

**Table 3. Average Electricity Rates for Major California Utilities.**

| Utility (2020 Sales >1 TWh) | 2020 Average Rate[a] ($/kWh) |
|---|---|
| San Diego Gas and Electric Company | $0.24 |
| Pacific Gas and Electric Company | $0.23 |
| Los Angeles Department of Water and Power | $0.19 |
| Southern California Edison | $0.16 |
| Turlock Irrigation District | $0.14 |
| Sacramento Municipal Utility District | $0.14 |
| Modesto Irrigation District | $0.14 |
| City of Santa Clara | $0.12 |
| Imperial Irrigation District | $0.12 |

[a] Average rate calculated as total annual revenue divided by total annual kWh sales, as reported to the U.S. Energy Information Administration (EIA) in EIA Form 861 (EIA 2020).

For pathways integrating hydrogen production with the wholesale market, we used LMP time-series data from ABB Velocity Suite (ABB 2018). For the colocation pathways, we selected LMP time series for solar and wind GEN nodes based on the minimum distance to a natural gas pipeline injection point, as described in Section 3. For the direct participation pathway, we used LMPs for the DLAP nodes; the 2019 hourly values are shown in Figure 8.

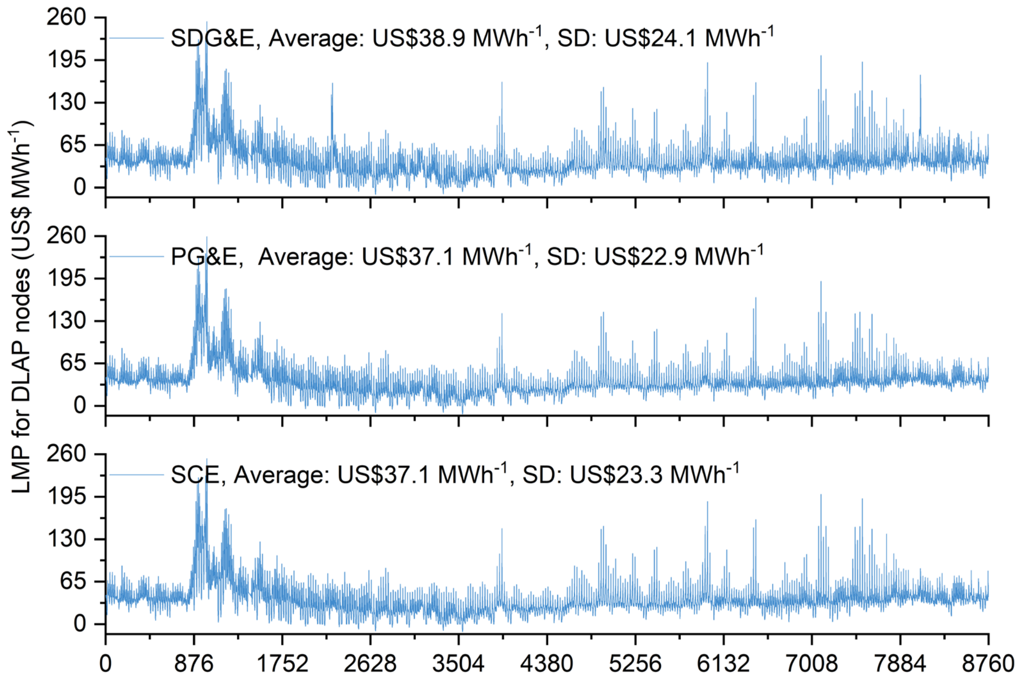


**Figure 8. LMP time series (year 2019) for the DLAP node associated with each utility territory.** SD denotes standard deviation.

For the direct participation pathway, we added an interconnection cost to the electrolyzer capital cost. This represents the cost of an electrical connection to the transmission system at transmission-level voltage (a cost that a typical retail electric customer does not incur). Table 4 summarizes the additional costs for each utility territory.

**Table 4. Interconnection Costs Added to Electrolyzer Capital Costs.**

| Interconnection Cost | Utility | | |
|---|---|---|---|
| | PG&E | SCE | SDG&E |
| **Substation** | $12,500,000 | $4,241,000 | $4,491,000 |
| **67-kV line (cost per mile)** | $1,140,000 | $1,925,000 | $4,000,000 |
| **Total gen-tie cost (10 miles)** | $23,900,000 | $23,491,000 | $44,491,000 |

Sources: PG&E, Generator Interconnection Unit Cost Guide, http://www.caiso.com/InitiativeDocuments/PGE2021FinalPerUnitCostGuide.xlsx; SCE, Generator Interconnection Unit Cost Guide, http://www.caiso.com/InitiativeDocuments/SCE2021FinalPerUnitCostGuide.xlsx; SDG&E, Generator Interconnection Unit Cost Guide, http://www.caiso.com/InitiativeDocuments/SDGE2021FinalPerUnitCostGuide.xlsx.

For 2030, the electricity tariffs and LMP data were adjusted based on electricity price projections from the U.S. Energy Information Administration (EIA), which are illustrated in Figure 9. In addition to the reference case projections, the EIA models sensitivities assuming either an abundance or a scarcity of oil and natural gas supply nationwide, which in turn would systematically push overall energy prices lower or higher. We used these two sensitivities and the effects EIA simulated for California to bracket a plausible range of electricity cost trajectories for 2030 (see Table 5). Note that for 2030 we assumed the same 2019 generation mix in CAISO but with higher electricity retail tariffs.

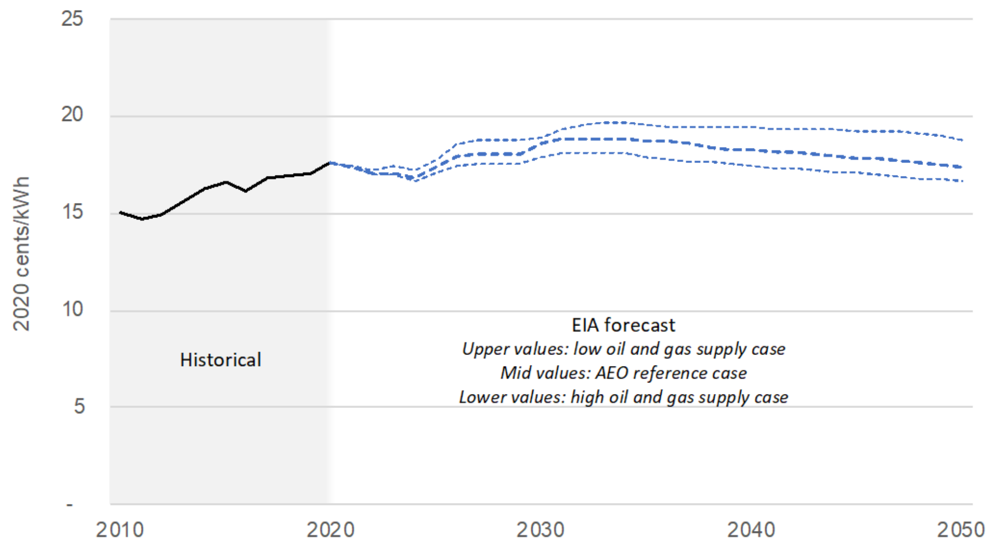


**Figure 9. Average retail electricity prices in California.**

Sources: Energy Information Administration, Form EIA 861 (historical prices) and Annual Energy Outlook 2021 (forecasted prices).

**Table 5. Projected 2030 Retail Tariff and LMPs.**

| Electricity Price | | Year 2019 | Year 2030 (EIA 2020) |
|---|---|---|---|
| | Min | Existing tariff | 2% higher |
| Tariff | **Average** | **Existing tariff** | **6% higher** |
| | Max | Existing tariff | 8% higher |
| | Min | Existing LMP data | 2% higher |
| LMPs | **Average** | **Existing LMP data** | **6% higher** |
| | Max | Existing LMP data | 8% higher |

### 4.2.2 Electrolyzer Cost, Financial, and Performance Assumptions

The cost of hydrogen technologies, including electrolyzers, is expected to decline in the future because of research-and-development activities as well as economies of scale resulting from deployment; thus, this analysis considers a decline in the electrolyzer capital expenditures (CAPEX) and operating expenditures (OPEX) by 2030, as described in Table 6. However, there are uncertainties regarding the technology evolution of hydrogen and the cost to deploy these technologies will depend on the location; therefore, in this analysis, we considered minimum and maximum values for electrolyzer's CAPEX and OPEX. The average CAPEX and OPEX values reported in Table 6 were used as the basis for the estimation of hydrogen breakeven costs, whereas the minimum and maximum values were used to perform the sensitivity and to quantify the effects of cost uncertainties on the hydrogen breakeven cost associated with the selected pathways. The assumptions regarding the financial and performance parameters for the electrolyzer are also summarized in Table 6. Note that this analysis used the same financial and performance assumptions for both the 2019 and 2030 timeframes (based on 1 MW electrolyzer, except for the conceptual pathway for which a 50 MW electrolyzer was used).

**Table 6. Techno-Economic and Financial Assumptions for the Electrolyzer**

| Parameter | | **Current (2019)** | **Projected (2030)** |
|---|---|---|---|
| **CAPEX ($/kW)** | Min | 1100.0 | 650.0 |
| | **Average** | **1450.0** | **1075.0** |
| | Max | 1800.0 | 1500.0 |
| **OPEX ($/kW-year)** | Min | 55 | 32.5 |
| | **Average** | **72.5** | **53.75** |
| | Max | 90 | 75 |
| Efficiency (kWh/kg) | | 54.3 | |
| Minimum part load (%) | | 10 | |
| Replacement cost ($/kW-year) | | 18.64 | |
| Hydrogen storage capital cost ($/kg) | | 822 | |
| Storage duration (hours at rated electrolyzer power) | | 8 | |
| Combined federal and state taxes (%) | | 27.95 | |
| Weighted average cost of capital (%) | | 7 | |
| Lifetime (years) | | 20 | |

(International Energy Agency 2019; J. D. Eichman et al. 2020)

### 4.2.3 Wind and Solar Photovoltaic Cost Assumptions and Generation Profiles

Time-synchronous generation profiles for wind and solar PV were generated, based on selected locations, using the Renewable Energy Potential (reV) model (Maclaurin et al. 2019) and 2012 weather data. For the PG&E locations, the capacity factor was 22.6% and 46.2% for the solar PV and wind facilities, respectively. Similarly, for the SCE locations, the capacity factor was 23.9% and 26.5% for the solar PV and wind facilities, respectively. In addition to the generation profiles, cost information for solar PV and wind was collected from the National Renewable Energy Laboratory's *Annual Technology Baseline 2020* (National Renewable Energy Laboratory 2020). For solar PV, single-axis tracking configuration was used. For wind, wind Class 7 and Class 10 technologies were used for the PG&E and SCE locations, respectively. Table 7 summarizes the CAPEX and OPEX assumptions for 2019 and 2030.

**Table 7. Cost Assumptions for Solar PV and Wind (National Renewable Energy Laboratory 2020).**

| | | | |
|---|---|---|---|
| **Solar PV** | | | |
| | | **Current (2019)** | **Projected (2030)** |
| **CAPEX ($/kW)** | Min | 1405.3 | 687.8 |
| | **Average** | **1405.3** | **836.4** |
| | Max | 1405.3 | 1223.4 |
| **FOM ($/kW-year)** | Min | 16.08 | 8.1 |
| | **Average** | **16.08** | **9.8** |
| | Max | 16.08 | 14.3 |
| Wind for PG&E location (Class 7) | | | |
| **CAPEX ($/kW)** | Min | 1862.9 | 911.1 |
| | **Average** | 1895.8 | 1473.5 |
| | Max | 1895.8 | 1538.1 |
| **FOM ($/kW-year)** | Min | 42.5 | 34.4 |
| | **Average** | **42.9** | **39.0** |
| | Max | 43.2 | 43.2 |
| Wind for SCE location (Class 10) | | | |
| **CAPEX ($/kW)** | Min | 2749.6 | 1028.9 |
| | **Average** | 2805.8 | 2056.5 |
| | Max | 2811.2 | 2234.9 |
| **FOM ($/kW-year)** | Min | 42.5 | 34.4 |
| | **Average** | **42.9** | **39.0** |
| | Max | 43.2 | 43.2 |

FOM = Fixed Operation and Maintenance.

# 5 Hydrogen Breakeven Cost for Selected Pathways

In this section, we summarize the results regarding the hydrogen breakeven cost for the selected pathways. Our calculations include the potential revenue from selling LCFS credits based on a value of $180/credit and the offset of the carbon emissions of light-duty vehicles by replacing gasoline with hydrogen in a hydrogen fuel cell electric vehicle (J. D. Eichman et al. 2020). Also, the capacity for the electrolyzer and the variable renewable energy (VRE) was fixed at 1 MW, except for the conceptual pathway "direct participation in CAISO." That pathway requires a larger scale to absorb the additional cost of interconnection; thus, the electrolyzer capacity selected for that pathway was 50 MW.

First, we present the RODeO results for the benchmark scenario, i.e., direct participation in the CAISO wholesale market for 2019. Then, we present the results for demand response and colocation pathways for the 2019 time frame, including a sensitivity on the electrolyzer's CAPEX and OPEX. Next, based on projected costs for VRE and electrolyzer equipment as well as forecasted energy prices, we discuss the estimated hydrogen breakeven cost for demand response and colocation pathways in 2030. These future simulations include sensitivities for electrolyzer costs, VRE costs, and energy prices. Finally, we summarize the preliminary results for the federal hydropower pathway.

## 5.1 Benchmark Results—Direct Participation in Wholesale Market

To create a benchmark for practicable hydrogen production opportunities, we evaluated a conceptual pathway based on direct participation in the CAISO wholesale market. As explained in Section 2.1, this pathway is currently not allowed under California law, but it can provide a standard for comparing pathways that are permissible since this pathway represents the least cost option for hydrogen production (J. D. Eichman et al. 2020). For this pathway, we used a 50-MW electrolyzer and the DLAP LMPs time series discussed in Section 4.2.1. Interconnection costs were included in the capital cost of the electrolyzer.

Figure 10 summarizes the breakeven cost for hydrogen production and the optimal electrolyzer capacity factor for this conceptual pathway in the 2019 time frame. As expected, the breakeven cost, which is equivalent to the minimum hydrogen selling price, for this conceptual pathway is relatively low. For example, the hydrogen breakeven cost for the "direct wholesale market participation in CAISO" pathway is near \$3.0 $kg^{-1}$ regardless of the utility territory. While the direct participation is not permissible today, this result acts as benchmark to see how different the hydrogen breakeven costs are for current configurations. For the "direct participation in CAISO" pathway, the cost drivers of hydrogen production are electricity cost, LCFS credits, and electrolyzer costs, in that order. Also, economies of scale affect the results due to the magnitude of the interconnection costs, which are included in CAPEX. A facility larger than 50 MW would have a lower cost per $kg^{-1}$, and a smaller facility would have a higher cost per $kg^{-1}$.

Under direct wholesale market participation, the electrolyzer is operated at a very high capacity factor, greater than 97%. This is driven by the relatively low electricity prices for the DLAP nodes. Finally, we performed a sensitivity analysis for electrolyzer costs (Figure A-1 and Figure A-2). A reduction of approximately 24% in the electrolyzer costs decreases hydrogen production cost by near 13% and the optimal electrolyzer capacity factor by ~2% (Figure A-1). On the other hand, an increase of approximately 24% in the electrolyzer costs increases hydrogen breakeven cost by approximately 13% and the optimal electrolyzer capacity factor by ~1% (Figure A-2).

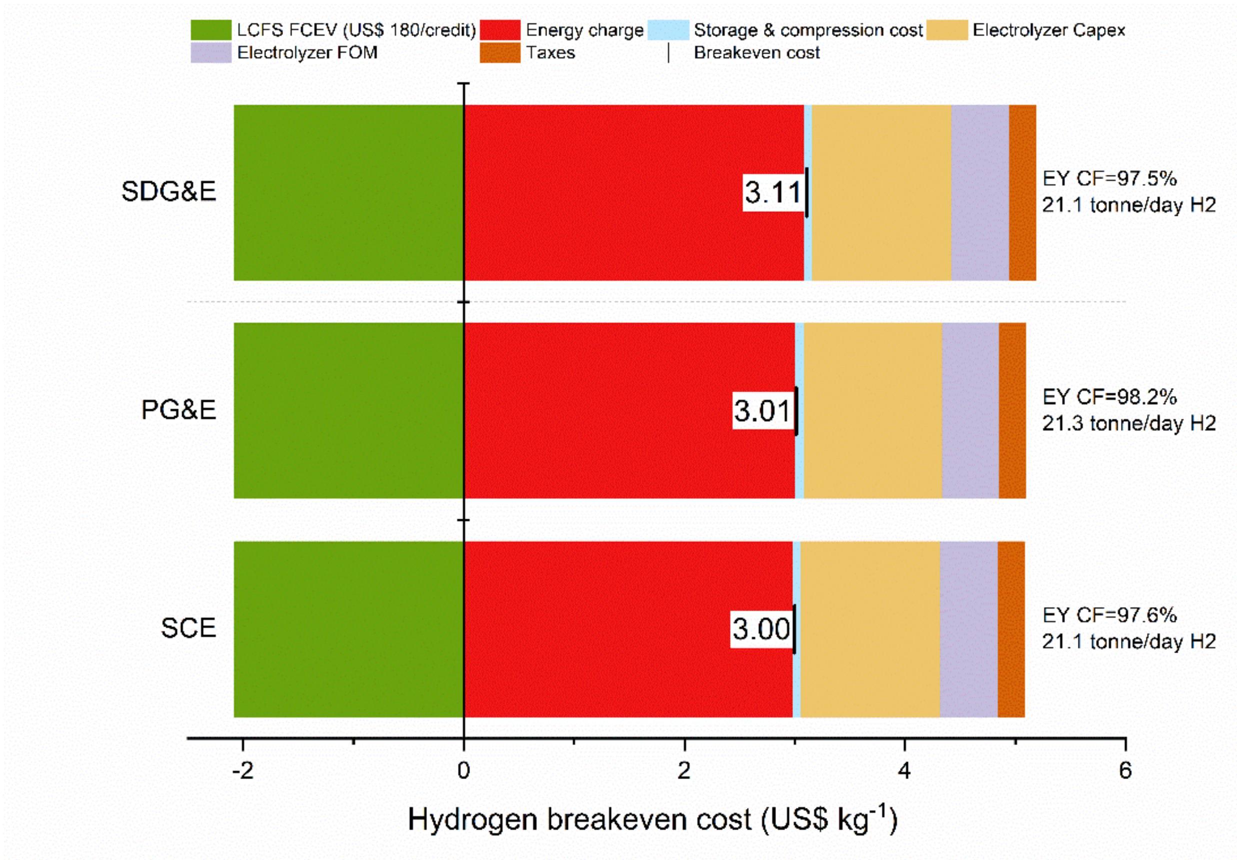


**Figure 10. Estimated 2019 hydrogen breakeven cost (horizontal bars) and optimal electrolyzer operation for the "direct wholesale market participation in CAISO" pathway and for each utility territory.** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 50 MW.

## 5.2 Results for Demand Response and Colocation Pathways in 2019

Based on the modeling framework and techno-economic assumptions described in Section 4, we estimated the hydrogen breakeven cost and the optimal operation of the electrolyzer for demand response and colocation pathways in the 2019 time frame. The corresponding results are analyzed in the next sections.

### *5.2.1 Demand Response (Retail Integration) Pathway*

For the demand response or retail integration pathway, we used the utility rates presented in Table 2. The results for each utility rate and the average cost values for the 2019 timeframe are summarized in Figure 11 (the average cost values for the electrolyzer and VRE presented in Table 6 and Table 7, respectively). In general, the hydrogen breakeven cost is higher for the PG&E and SDG&E territories, ranging from \$8.7 $kg^{-1}$ to \$9.8 $kg^{-1}$, depending on the retail tariff. In contrast, the hydrogen breakeven cost for the SCE territory ranges from \$4.7 $kg^{-1}$ (RTP tariff) to \$5.7 $kg^{-1}$ (TOU tariff)—from \$2.9 $kg^{-1}$ to \$5.1 $kg^{-1}$ cheaper than the cost to produce hydrogen in PG&E or SDG&E. Moreover, SCE's RTP tariff has the lowest hydrogen breakeven cost, which represents a cost reduction of approximately 19% from the baseline TOU tariff (SCE's TOU-8-D); thus, RTP tariffs seem to be attractive for the demand response or retail integration pathway. The cost of electricity, comprising energy and demand charges, is the major cost driver for grid-based electrolytic hydrogen production regardless of the specific utility territory or tariff type. Other important cost drivers for this production pathway are the LCFS credits and the capital cost of the electrolyzer.

Regarding the optimal electrolyzer operation, the optimal capacity factor for the PG&E and SDG&E tariffs tends to be higher than 83%, which is driven by the structure of the retail tariffs, e.g., off-peak and mid-peak energy and demand charges. Additionally, the optimal electrolyzer capacity factor is equal to or less than 83% for the SCE tariffs, which have relatively cheaper off-peak energy charges in comparison with PG&E and SDG&E tariffs. To quantify the effects of electrolyzer cost uncertainties on the hydrogen breakeven cost, a sensitivity analysis was implemented based on the low and high CAPEX and OPEX values reported in Table 6. The corresponding results are presented in Figure A-3 and Figure A-4. In summary, a reduction of 24% in the electrolyzer costs decreases the hydrogen breakeven cost by 9%, 5%, and 7% for SCE, PG&E, and SDG&E, respectively (see Figure A-3). On the other hand, an increase of 24% in the electrolyzer costs increases the hydrogen breakeven cost by 9%, 5%, and 5% for SCE, PG&E, and SDG&E, respectively.

Notably, for PG&E and SDG&E, the impact of reducing CAPEX and OPEX is small compared to the overall differences between those two utilities and SCE. PG&E and SDG&E have the most expensive rates in California, whereas SCE is near the median (see Table 3). Consequently, the breakeven cost of producing hydrogen under SCE's current TOU tariff is approximately 34% less than under PG&E's current TOU tariff. This suggests that regardless of possible reductions in CAPEX and OPEX, access to low-cost electricity is crucial to achieving cost-effective hydrogen production.

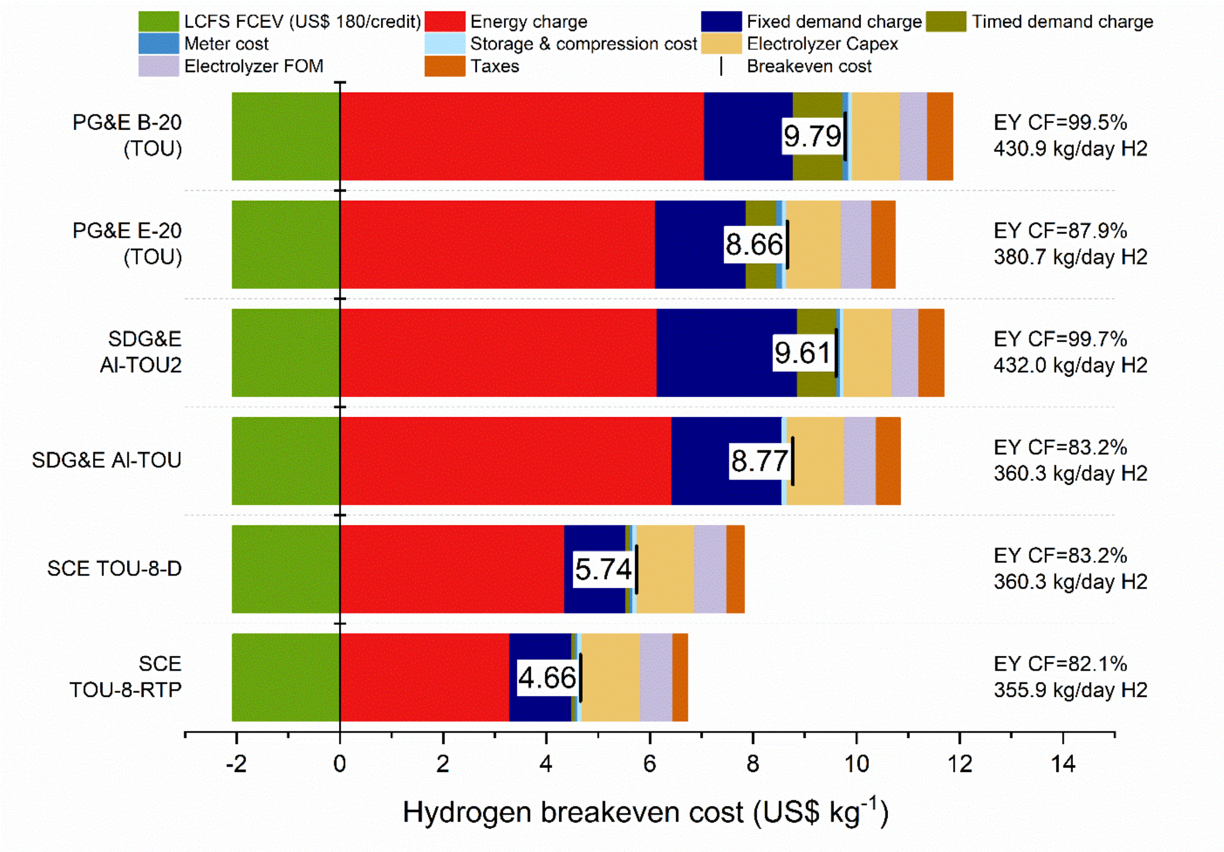


**Figure 11. Estimated 2019 hydrogen breakeven cost and optimal electrolyzer operation for the demand response or retail integration pathway.** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 1 MW.

### 5.2.2 Colocation pathway (Integration with Solar PV or Wind Facilities)

In addition to the demand response or retail integration pathway, we evaluated the hybrid colocation pathway with solar PV and wind facilities for the PG&E and SCE territories. The selection of the locations for the corresponding solar PV and wind facilities were described in Section 3. Additionally, the tariffs PG&E E-20-R and SCE TOU-8-R were selected for the hybrid colocation pathways in PG&E and SCE, respectively. The results for the 2019 time frame are illustrated in Figure 12 using average values for VRE and electrolyzer costs. The results for the corresponding baseline retail integration tariff were also included, e.g., PG&E E-20 and SCE TOU-8-D tariffs for PG&E and SCE, respectively. It is observed that, compared to the demand response pathway (results are included in Figure 12), the colocation of hydrogen production systems with on-site solar PV facilities reduces the hydrogen breakeven cost by 15% and 6% for PG&E and SCE, respectively. On the other hand, the results for colocation with wind facilities depends on the capacity factor of the wind facility (27% for SCE and 46% for PG&E). For instance, colocation with a wind facility reduces the hydrogen breakeven cost with respect to the demand response pathway in PG&E but increase the hydrogen breakeven cost with respect to the retail integration pathway in SCE. For the colocation hydrogen production pathway, the major cost drivers are electricity costs, LCFS credits, VRE costs, and electrolyzer costs. In summary, the electrolyzer is operated at a relatively high capacity factor (greater than 62%) because the variable wind or solar PV power input is complemented with grid-based power.

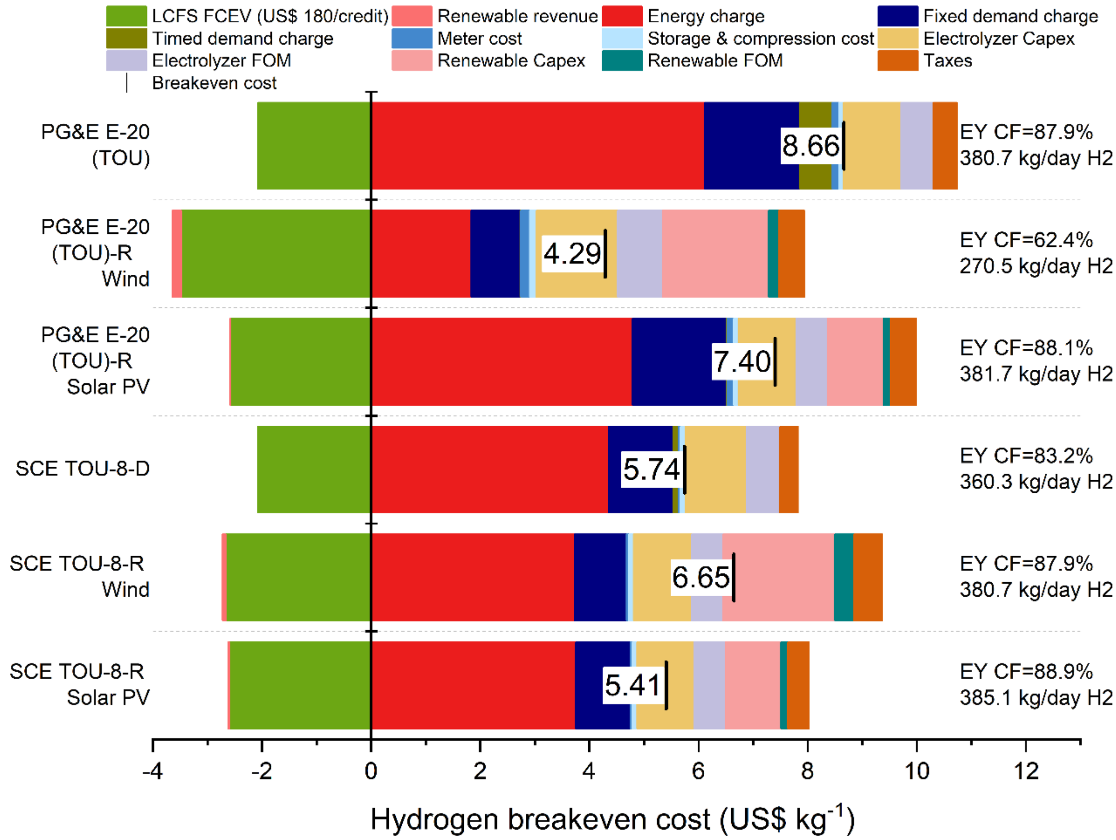


**Figure 12. Estimated 2019 hydrogen breakeven cost and optimal electrolyzer operation for colocation with 1 MW wind and 1 MW solar PV facilities.** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 1 MW. Results for the demand response pathways are included as a reference.

Finally, we performed a sensitivity analysis for the electrolyzer costs (see Figure A-5 and Figure A-6). In summary, a reduction of 24% in the electrolyzer costs decreases the hydrogen breakeven cost by 7% and 11% for the colocation pathway in SCE and PG&E, respectively (see Figure A-5). On the other hand, an increase of 24% in the electrolyzer costs increases the hydrogen breakeven cost by 7% and 11% for the colocation pathway in SCE and PG&E, respectively (see Figure A-6).

## 5.3 Results for Demand Response and Colocation Pathways in 2030

In this section, we present the estimated hydrogen breakeven cost by 2030 for the demand response (retail integration) and hybrid colocation pathways. The “direct participation in CAISO” pathway was not included because of the uncertainties around the interconnection costs for 2030. Note that the 2030 results are based on updated retail tariffs, LMPs, solar PV and wind costs, and electrolyzer costs, as described in Section 4.2.

### *5.3.1 Demand Response (Retail Integration) Pathway*

The average projected values for electrolyzer costs and electricity prices (see Table 5 and Table 6) were used to project the hydrogen breakeven cost by 2030 for the demand response or retail integration pathway. The results are summarized in Figure 13. From 2019 to 2030, hydrogen breakeven costs are projected to decrease by approximately 4% on average for SCE, the utility territory with the lowest electricity costs and hydrogen breakeven costs. In contrast, from 2019 to 2030, hydrogen breakeven costs are expected to increase for the PG&E and SDG&E territories, except for the PG&E B-20 (TOU) utility rate. This increase is driven by the projected 6% increase in electricity prices, e.g., see Table 5, assumed in this analysis.

Note that electricity cost is by far the most important cost driver for these utility territories; thus, the projected 2030 decrease in electrolyzer costs is not enough to compensate for the increase associated with electricity costs. For this pathway, 2030 hydrogen breakeven costs are projected to be between \$4.4 $kg^{-1}$ and \$9.8 $kg^{-1}$, depending on the utility territory. As in the 2019 results, the SCE RTP tariff has the lowest hydrogen breakeven cost, which is projected to be approximately \$4.4 $kg^{-1}$. Additionally, the electrolyzer is operated at a relatively high capacity factor (greater than 79%), which is driven by the electricity prices.

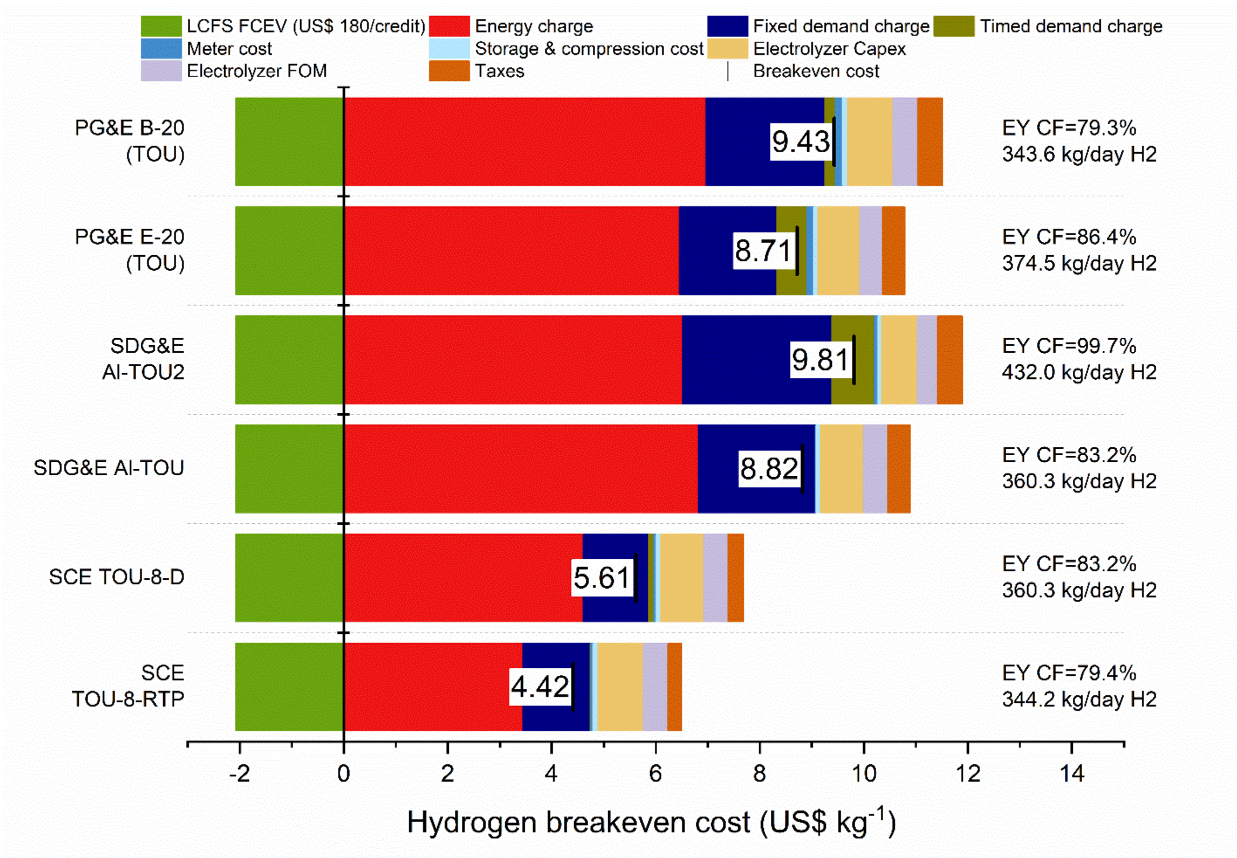


**Figure 13. Projected 2030 hydrogen breakeven cost and optimal electrolyzer operation for the demand response or retail integration pathway.** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 1 MW.

### 5.3.2 Colocation Pathway (Integration with Solar PV or Wind Facilities)

To estimate the projected 2030 hydrogen cost for the colocation pathway, we used the average 2030 projected values for VRE costs, electrolyzer costs, and electricity prices (see Table 5, Table 6, and Table 7) to optimize the operation of hybrid hydrogen production facilities with a 1-MW electrolyzer and 1-MW solar PV or wind plant. The results are presented in Figure 14. For this pathway, the hydrogen breakeven costs are projected to decrease from 2019 to 2030 by approximately 14% and 23% on average for the SCE and PG&E territories, respectively. In general, 2030 hydrogen breakeven costs for the hybrid colocation pathway are projected to be between \$3.4 $kg^{-1}$ and \$5.8 $kg^{-1}$, depending on the utility territory. Figure 14 compares the hybrid colocation results with those of a straight demand response pathway using a TOU tariff. The electrolyzer operates at a relatively low capacity factor for the PG&E territory using the hybrid colocation pathway. The optimal electrolyzer capacity factor is greater for the same pathway in the SCE territory.

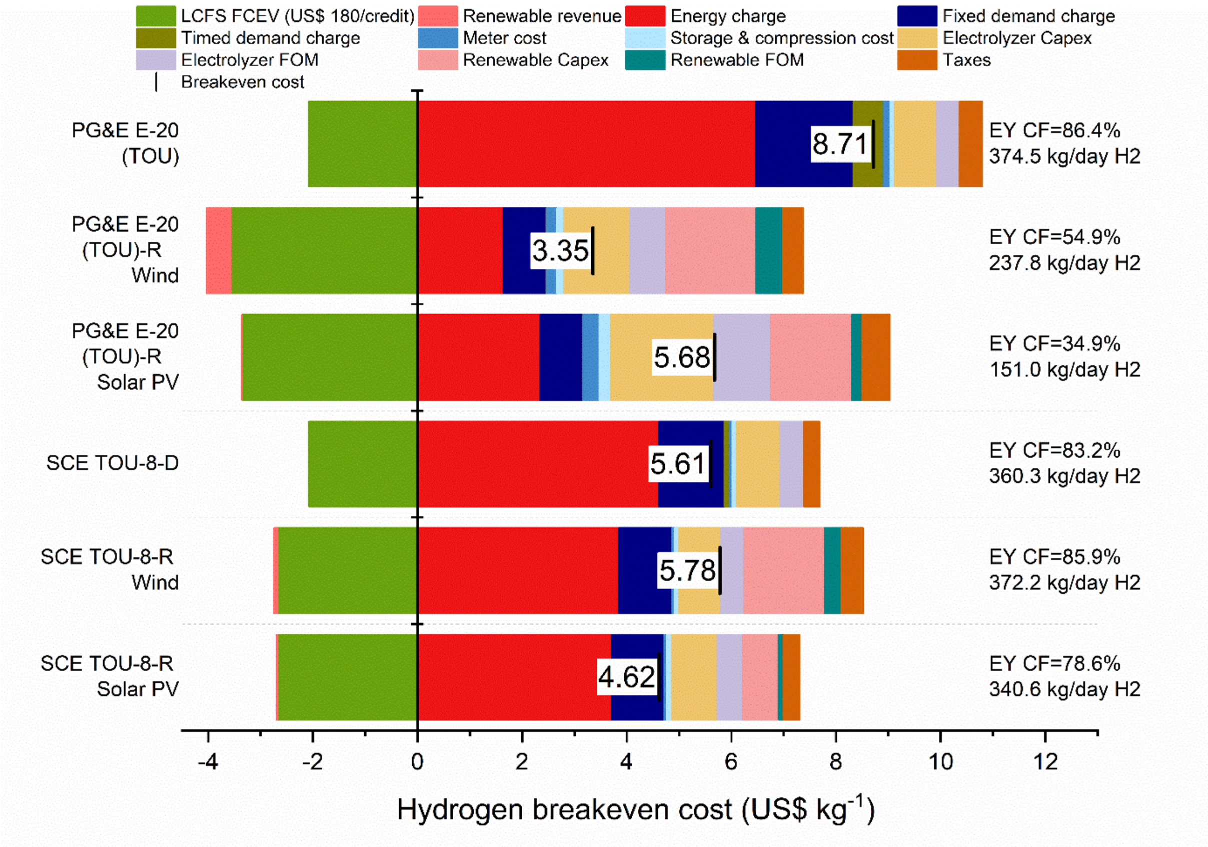


**Figure 14. Projected 2030 hydrogen breakeven cost and optimal electrolyzer operation for colocation with 1 MW wind and 1 MW solar PV facilities.** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 1 MW. Results for the demand response pathways are included as a reference.

Figure A-7 and Figure A-8 summarize the cost sensitivity cases. With low VRE costs, electrolyzer costs, and electricity prices, 2030 hydrogen breakeven costs are projected to be between \$1.0 $kg^{-1}$ and \$3.8 $kg^{-1}$ for the hybrid colocation pathways, depending on the utility territory. In the high-cost sensitivity, 2030 hydrogen breakeven costs are projected to be between \$4.5 $kg^{-1}$ and \$7.9 $kg^{-1}$ (depending on the utility territory) for the hybrid colocation pathway; thus, the U.S. Department of Energy's Hydrogen Energy Earthshot target (\$1.0 $kg^{-1}$) (U.S. Department of Energy (DOE) 2021) could be feasible for the hybrid colocation pathway, but it requires a combination of low VRE costs, low electrolyzer costs (\$650.0 per kW or cheaper), low electricity prices, and locations with high capacity factors for VRE. In summary, these results show that the evolution of hydrogen breakeven costs in the near future will depend on the technology evolution of VRE and electrolyzer technologies as well as electricity markets.

## 5.4 Preliminary Results for Federal Hydropower Pathway

Finally, we conducted a preliminary analysis of hydrogen production using federal hydropower. This special scenario is institutionally complicated, however, and it was beyond the scope of this study to fully investigate the legal feasibility of this pathway. Native American tribes, municipalities, and other public entities in California hold entitlements to federal hydropower administered through the Western Area Power Administration (WAPA). Although this electricity is significantly lower in cost than electricity obtained through a utility or even directly from the CAISO wholesale market, there might be other conditions governing its use that could affect the ability to use it for hydrogen production.

Table 8 shows the results of the tentative hydrogen breakeven cost analysis for 2019. Although the actual feasibility of this pathway remains unclear, the preliminary economic indications suggest that further investigation is warranted. If all other factors are held constant, federal hydropower could enable hydrogen production at costs less than the wholesale benchmark and possibly approaching the U.S. Department of Energy's $1/kg target.

**Table 8. Tentative Hydrogen Breakeven Cost for the Federal Hydropower Pathway, Simulation for 2019 ($/kg).** Results for direct wholesale market participation, demand response, and colocation pathways are included as a reference.

| Electrolyzer Cost Scenario | Using Federal Hydropower | Benchmark (Direct Wholesale Access, SCE DLAP Zone) | SCE Retail (RTP) | SCE Hybrid Colocation with Solar PV |
|---|---|---|---|---|
| Low | 0.88 | 2.60 | 4.18 | 4.97 |
| Midrange | 1.13 | 3.00 | 4.66 | 5.41 |
| High | 1.39 | 3.39 | 5.13 | 5.84 |

These results come with two major caveats. First, the category of cost assumptions—energy costs, equipment costs, non-bypassable distribution costs—included in this pathway are the same as those included in other pathways; however, there might be other external costs associated uniquely with federal hydropower that were inadvertently not included in our modeling. This is an area that should be explored further in follow-up analysis. Second, for many entitlement holders, this power is a relatively scarce energy resource that might be fully committed to other uses, making it unavailable for hydrogen generation.

# 6 Conclusions and Outlook

Hydrogen can play a critical role in achieving 100% carbon-free or renewable energy systems while facilitating the integration of wind and solar PV power sources into different energy sectors. For instance, electrolytic hydrogen could be an additional bridge between renewable energies and the transportation, industrial, and heating sectors. Indeed, hydrogen injection into the natural gas network has emerged as a potentially cost-competitive alternative to transport hydrogen for a variety of end-use applications that could use hydrogen-natural gas blends or pure hydrogen after downstream separation.

But the cost to produce electrolytic hydrogen as well as the integration with electricity markets require better understanding to fully recognize the value of hydrogen technologies in future energy systems. Thus, in this study, we explored the hydrogen breakeven cost for different pathways in view of hydrogen injection into the natural gas network in California.

Regardless of the pathway for electrolytic hydrogen production, electricity is a key cost driver. Thus, integration with electricity markets, e.g., via dynamic retail tariffs or direct wholesale market participation, and cheap renewable power sources could help to achieve low breakeven costs for electrolytic hydrogen. For example, **low hydrogen breakeven cost could be achieved today via direct wholesale market participation, e.g., ~$3/kg**. Although direct wholesale access is currently prohibited in CAISO under state law, it is permissible in other organized wholesale markets. Additionally, the profitability of hydrogen production also depend on electrolyzer siting, even as CAPEX and OPEX continue to drop. This study has shown that, based on the demand response pathway, **the cost of producing hydrogen in the PG&E or SDG&E territories, which have the highest retail tariffs in California, would be much higher than producing it in SCE's territory**. Previous studies have shown that the hydrogen breakeven cost between the three major investor owned utilities in California was more similar in the past and has only recently diverged (J. Eichman and Flores-Espino 2016). Reducing the CAPEX and OPEX in PG&E or SDG&E would reduce only a portion of that gap. Many smaller utilities in California—especially publicly owned utilities with access to low-cost federal hydropower—have retail rates that are less than those of SCE and could provide even greater cost savings.

Another strategy for reducing costs through siting decisions is to combine hydrogen production with utility-scale wind or solar PV power plants located in parts of the grid that are especially susceptible to low or negative wholesale electricity prices. When wholesale prices are low, diverting generator output to hydrogen production would be an alternative to delivering power to the grid at a loss. For example, based on 2019 assumptions, **colocation of electrolyzer with solar PV could reduce the hydrogen breakeven cost by 15% and 6% for PG&E and SCE, respectively**. Of the pathways simulated in this study and excluding the special federal hydropower pathway, only **the colocation pathway had a scenario capable of reaching the breakeven cost target of $1/kg by 2030, but it requires a combination of low VRE costs, low electrolyzer costs ($650.0 per kW or cheaper), low electricity prices, and locations with high capacity factors for VRE**.

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# Appendix A. Hydrogen Breakeven Cost Sensitivities

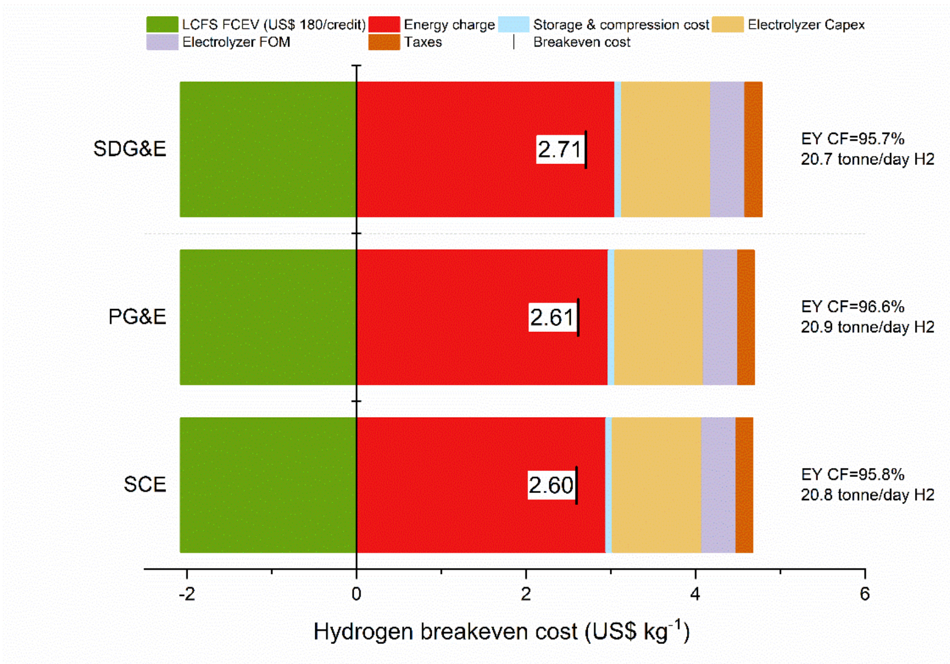


**Figure A-1. Estimated 2019 hydrogen breakeven cost and optimal electrolyzer operation for the "direct wholesale market participation in CAISO" pathway and minimum electrolyzer costs (sensitivity).** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 50 MW.

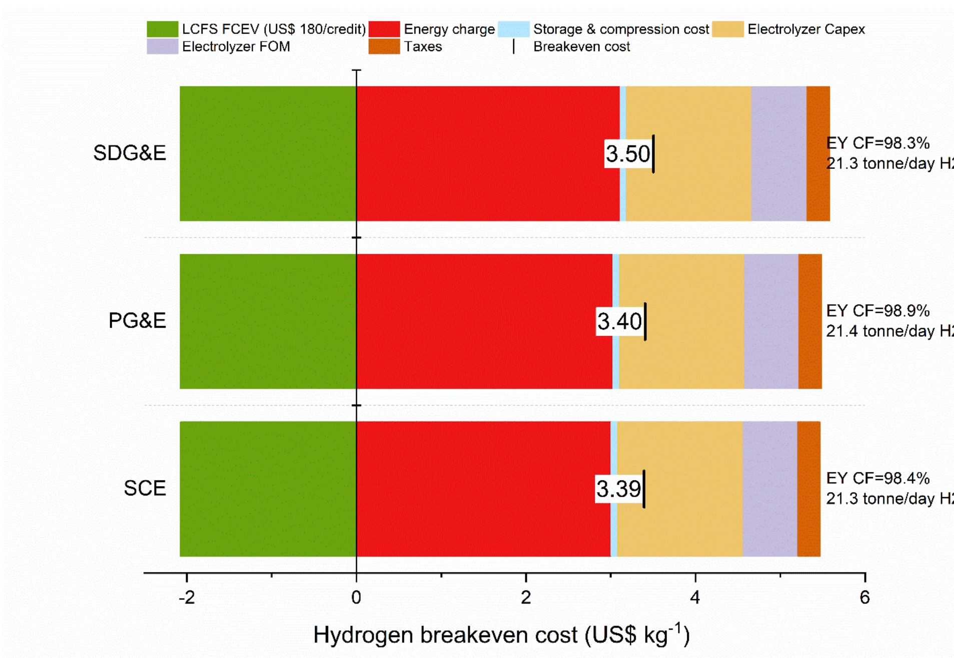


**Figure A-2. Estimated 2019 hydrogen breakeven cost and optimal electrolyzer operation for the "direct wholesale market participation in CAISO" pathway and maximum electrolyzer costs (sensitivity).** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 50 MW.

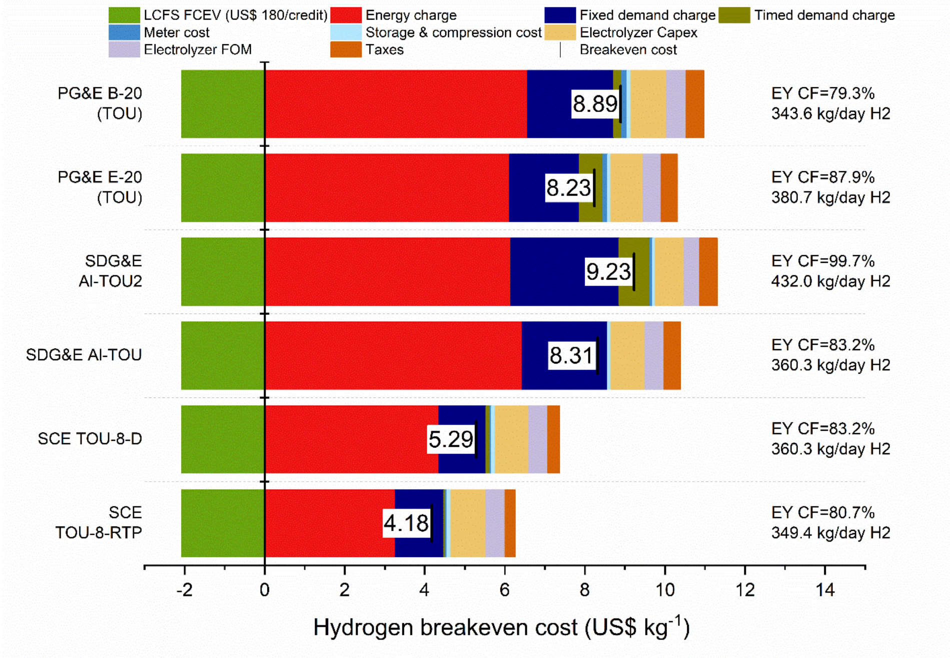


**Figure A-3. Estimated 2019 hydrogen breakeven cost and optimal electrolyzer operation for the demand response or retail integration pathway and minimum electrolyzer costs (sensitivity).** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 1 MW.

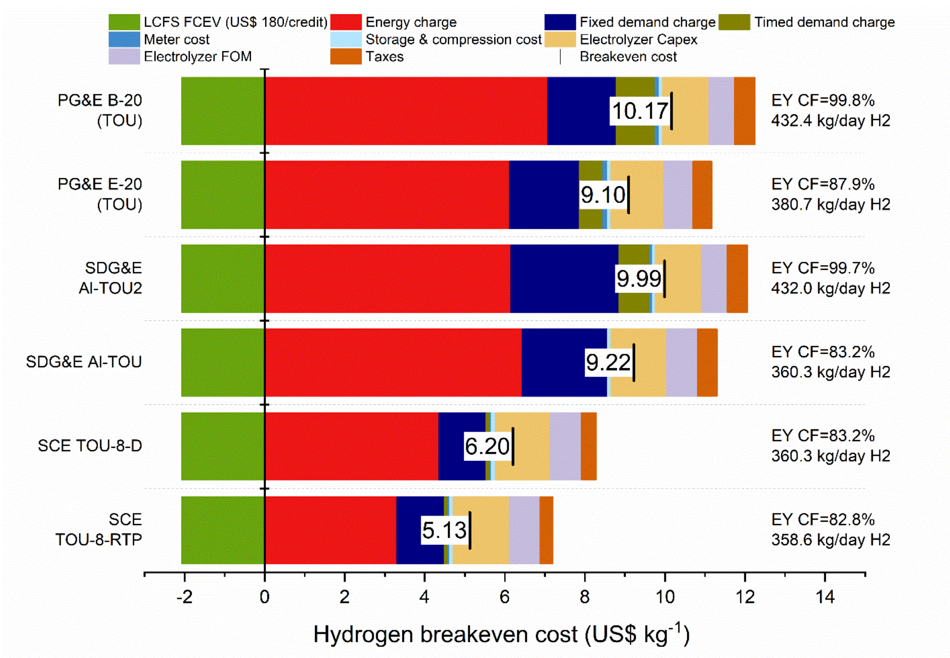


**Figure A-4. Estimated 2019 hydrogen breakeven cost and optimal electrolyzer operation for the demand response or retail integration pathway and maximum electrolyzer costs (sensitivity).** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 1 MW.

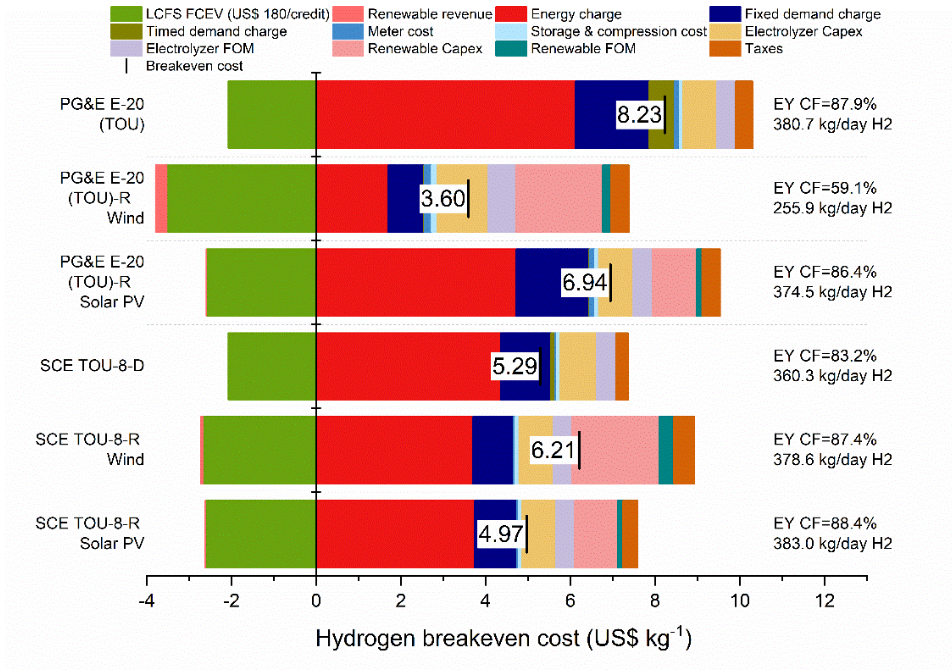


**Figure A-5. Estimated 2019 hydrogen breakeven cost and optimal electrolyzer operation for colocation with 1 MW wind and 1 MW solar PV facilities and minimum electrolyzer costs (sensitivity).** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 1 MW.

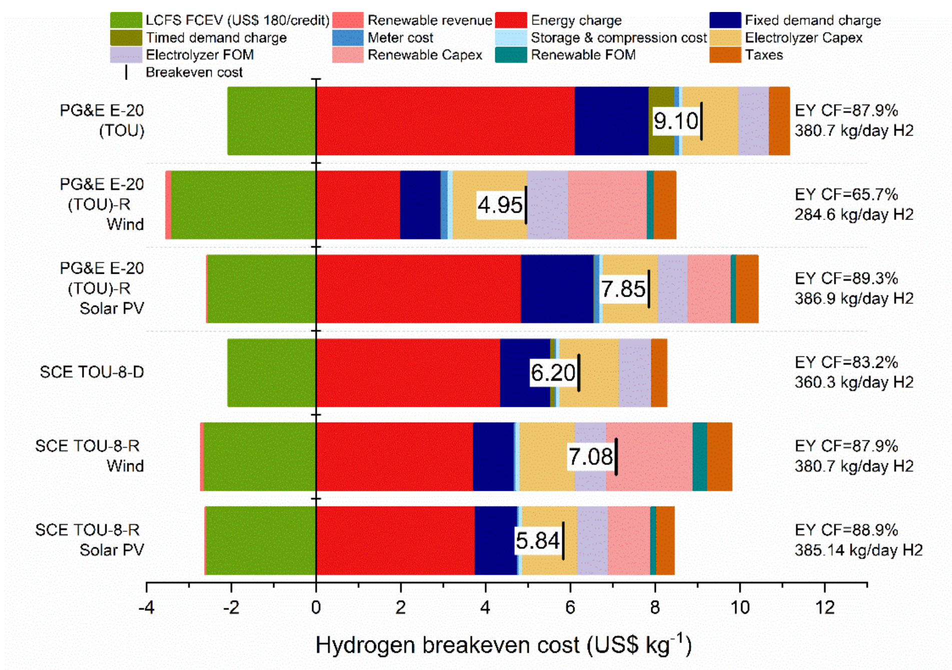


**Figure A-6. Estimated 2019 hydrogen breakeven cost and optimal electrolyzer operation for colocation with 1 MW wind and 1 MW solar PV facilities and maximum electrolyzer costs (sensitivity).** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 1 MW.

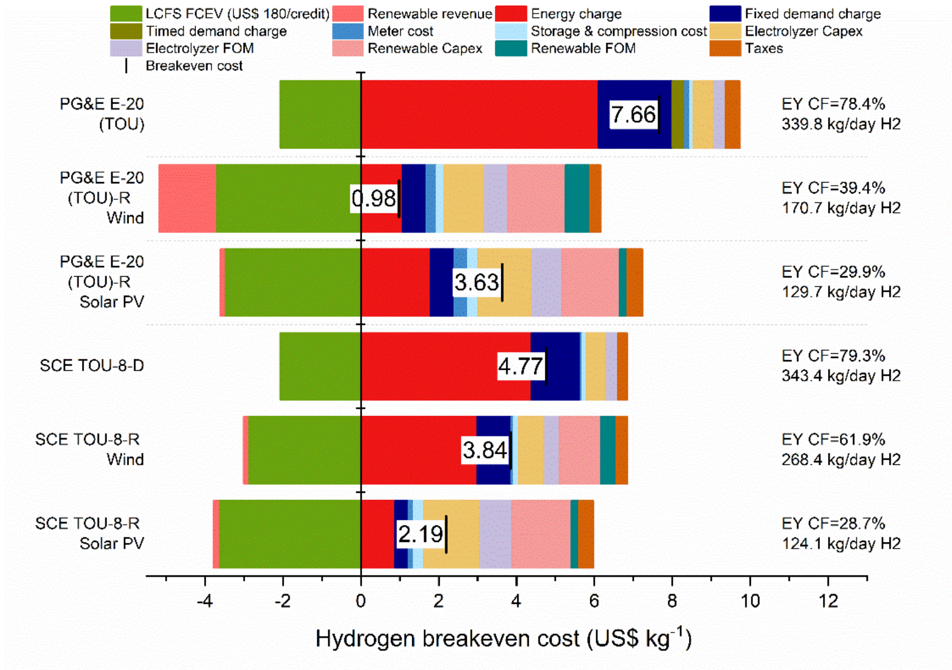


**Figure A-7. Projected 2030 hydrogen breakeven cost and optimal electrolyzer operation for colocation with 1 MW wind and 1 MW solar PV facilities and minimum VRE costs, electrolyzer costs, and electricity prices (sensitivity).** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 1 MW.

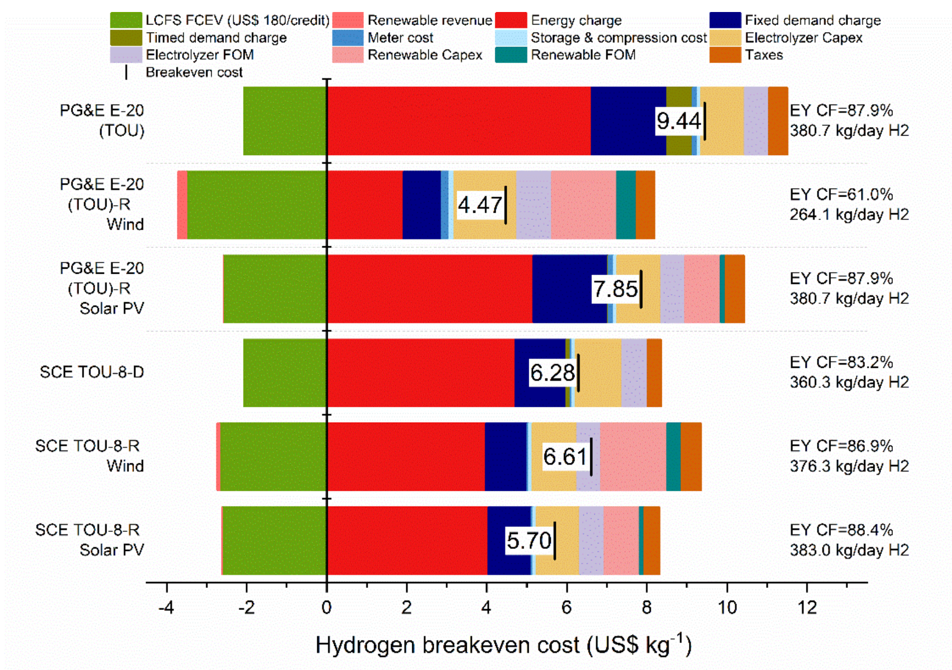


**Figure A-8. Projected 2030 hydrogen breakeven cost and optimal electrolyzer operation for colocation with 1 MW wind and 1 MW solar PV facilities and maximum VRE costs, electrolyzer costs, and electricity prices (sensitivity).** EY denotes electrolyzer, and CF denotes capacity factor. The capacity of the electrolyzer is 1 MW.

# Appendix B. Adjustments to Wholesale Prices

Historical data on variable renewable energy (VRE) production and wholesale prices need to be time matched if the two are being analyzed together. This is especially important where the amount of solar on the grid is large enough to affect wholesale prices; during hours when VRE production increases, prices tend to decrease. The most recent year for which validated 5-minute solar data coincide with CAISO hourly LMPs is 2012 (see Table A-1.).

**Table A-1. Change in Wholesale Energy Prices.**

| | Average System energy price ($/MWh) | Change from 2012 |
|---|---|---|
| 2012 | 29.542 | |
| 2019 | 37.459 | 27% |
| 2020 | 34.783 | 18% |

We used the difference in average annual system energy prices between 2012 and 2019 to adjust the 2012 LMPs to a 2019 equivalent. System energy price is one of three LMP components and represents the system-wide marginal cost of energy, without accounting for transmission congestion and line losses (congestion and losses are separate LMP components). Momentary real-time events can cause local congestion for reasons unrelated to system-wide energy costs; thus, trends in the system energy price by itself are a more accurate indicator of long-term system-wide trends in underlying energy costs than average LMPs would be.

This adjustment does not account for the possibility that congestion might have behaved differently in 2019 than it did in 2012 because of transmission upgrades completed after 2012. Nevertheless, such deficiencies are less problematic than using LMP and VRE output data that are not matched in time.

Although 2019 was chosen as the test year for this analysis, we also compared system energy prices for 2020. Prices were slightly lower than for 2019, likely because of decreased electricity demand related to the COVID-19 pandemic.