California Power-to-Gas and Power-to-Hydrogen Near-Term Business Case Evaluation

Josh Eichman and Francisco Flores-Espino

National Renewable Energy Laboratory

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List of Acronyms

BIP	Base interruptible program
CAISO	California Independent System Operator
CCA	Community Choice Aggregators
CCS	Carbon capture and sequestration
CF	Capacity factor
CI	Carbon intensity
CNG	Compressed natural gas
CPUC	California Public Utilities Commission
CSD	Compression, storage, and delivery
DR	Demand response
DRAM	Demand Response Auction Mechanism
EER	Energy Economy Ratio
ESDER	Energy Storage and Distributed Energy Resources
FCEV	Fuel cell electric vehicle
FOM	Fixed operation and maintenance
HCNG	Hydrogen and compressed natural gas
HDSAM	Hydrogen Delivery Scenario Analysis Model
IOU	Investor owned utility
ISO	Independent System Operator
LCFS	Low Carbon Fuel Standard
MW	Megawatt
NGR	Non-Generator Resource
OASIS	Open Access Same-Time Information System
PDR	Proxy Demand Resource
PG&E	Pacific Gas and Electric
PPA	Power Purchase Agreement
PV	Photovoltaic
RDRR	Reliability Demand Response Resource
RFS	Renewable Fuel Standard
RIN	Renewable identification number
RTP	Real-time Price
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SMR	Steam methane reformer
T&D	Transmission and distribution
TOU	Time-of-use

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Executive Summary

Hydrogen production from electrolysis offers a unique opportunity to integrate multiple energy sectors, contributing to greater flexibility and potentially more clean and efficient operation for each energy sector. Hydrogen can be made from a wide variety of feedstocks and used for an even wider set of end uses, including transportation fuel, heating fuel, regeneration of electricity, refinery feedstock, fertilizer feedstock, and other industrial processes. Electrolysis is one of the most promising hydrogen production techniques because of its ability to use renewable electricity to make hydrogen while simultaneously supporting grid needs with flexible, fast responding operation. Changing the time that electrolyzers produce hydrogen to match grid needs can increase the renewable content of the fuel and the capacity of the grid to support intermittent renewables, as well as improve the economics for hydrogen production. The focus of this report is to explore the near-term business cases for renewable and flexible hydrogen production using electrolysis in California.

Near-term opportunities in California show a potential cost reduction of $2.5/kg (21%) for the production and delivery of electrolyzed hydrogen without any impact to hydrogen consumers. This is accomplished by shifting the production schedule to avoid high-cost electricity and by participating in utility and system operator markets along with installing renewable generation to avoid utility charges and increase revenue from the Low Carbon Fuel Standard (LCFS) program. Future strategies are suggested for further reducing the cost of hydrogen and could provide an additional 29% reduction in the cost.

Recognizing the value of hydrogen as a renewable and flexible energy carrier, the authors have focused this report on two configurations: 1) power-to-hydrogen, converting electricity to hydrogen that will be sold as a transportation fuel or for industrial processes, and 2) power-to-gas, converting electricity to hydrogen that will either be converted to methane or directly injected into the natural gas system.

The following sections provide a summary of the main results for this report including overall cost impacts, specific scenario results, additional sensitivity analyses, and recommendations for state and federal agencies.

Summary of Cost Impacts

Several opportunities exist that electrolyzer operators can currently take advantage of to generate additional revenue and reduce energy costs while producing a renewable product and supporting electric grid needs. These are discussed below and presented in Figure ES-1. These cost reduction opportunities are relevant for electrolyzer manufacturers, utilities, grid operators, and regulatory agencies because they represent areas where changes to existing rules will impact the business case for electrolysis. The following impacts are representative of a megawatt-scale

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electrolyzer producing hydrogen for fuel cell electric vehicle (FCEV)[1] fuel with co-located renewables[2].

1. For simplicity, electrolyzers are generally operated at a constant power level and rarely change their set point. Changing the operation profile to avoid high energy and demand charges can reduce the production cost for hydrogen by 6%–7% without impacting the hydrogen supply to customers. This value is based on current California investor-owned-utility (IOU) time-of-use (TOU) rates and will change based on changes to the TOU rates and participation in real-time pricing or other rate schedules.

2. The addition of on-site renewables can further reduce the energy and demand charges, particularly for PV, as well as increase the number of LCFS credits obtained by increasing the renewable content of the hydrogen. Even after purchasing renewable capacity the total cost of producing and delivering hydrogen reduces between 7% and 10% using California utility rates and an LCFS credit value of $125.

3. There are a variety of existing demand response programs in which flexible load such as that offered by electrolyzers can participate. Most of these programs are for resource adequacy and consist of a load reduction for specific events called by the utility or grid system operator. These events can occur as little as once per year or as often as several dozen times per year and are triggered by a variety of conditions including system operator load forecast, temperature, generation resource inadequacies, and reliability needs. Demand response programs are examined, and the program value for Pacific Gas and Electric (PG&E) is up to $0.54/kg (5% reduction).

4. California Independent System Operators (CAISO) has programs that enable demand response to participate in energy and/or ancillary service markets. In addition, CAISO is facilitating stakeholder processes with the goal of lowering the barriers for grid-connected storage and distributed energy resources to participate in independent system operator (ISO) markets. Presently the equipment and method required to verify participation limit the cost effectiveness of participation in these markets. As a result, this study focuses on only ancillary services and finds that provision of spinning reserve capacity can provide 1%–2% reduction in hydrogen production and delivery cost. This assessment does not include energy payments that would be received when the spinning reserve is called by the ISO, which could further increase the overall reduction.

In addition to near-term options that are currently available, several longer-term options that are currently unavailable are explored. These items show the relative importance of each item and can help research organizations, manufacturers, regulatory agencies and third-party installers and operators to prioritize their efforts. Each item can be pursued independently, and the final bar in Figure ES-1 shows the aggregate impact that would result if all items are realized.

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[1] This study does not discriminate between fuel cell vehicle type, meaning that these results could be applied to fuel delivered for light-duty passenger vehicles and medium- and heavy-duty vehicles.

[2] The renewable installation is the same size as the electrolyzer for reasons described in detail in the report (i.e., 1 MW electrolyzer and 1 MW of renewables)

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1. Access to lower cost capital for projects can reduce the cost of electrolysis equipment. The cost model for this study is relatively simple and assumes 100% debt payment for capital. Including equity at the time of purchase and including more sophisticated tax strategies and incentives can impact the capital cost of equipment. To show the relative impacts for receiving lower cost of capital, the interest rate on debt was reduced from 7% to 5%, resulting in a nearly 5% reduction on overall hydrogen cost.

2. At present, hydrogen using a renewable electrolysis pathway is not eligible for Renewable Fuel Standard (RFS) credits. If the RFS pathways are expanded to include electrolytic hydrogen production, electrolyzers could receive \$0.44/kg for D6 renewable identification numbers (RINs) or \$0.57/kg for D5 RINs, which represents 4%–5% reduction from baseload production and delivery cost.

3. Research and development by the manufacturers, the U.S. Department of Energy (DOE) and other organizations seeks to lower the cost for electrolyzers and balance of plant. A capital cost reduction of 56% down to \$1,460/kW (includes installation and fixed operation and maintenance) results in a cost reduction of \$1.2/kg (10.44%).

4. The LCFS credit incentivizes the adoption of low carbon transportation fuels. LCFS credits at \$125/credit provide up to \$3.48/kg depending on the fuel pathway and renewable penetration selected. Exploring the value for increasing the LCFS credit value provides a measure for the impact on hydrogen cost. Increasing the credit value from \$125 to \$200/credit yields more than a \$1/kg increase in revenue (9%). More installed renewables can further increase the LCFS impact but the feasibility depends on the specific site selected.

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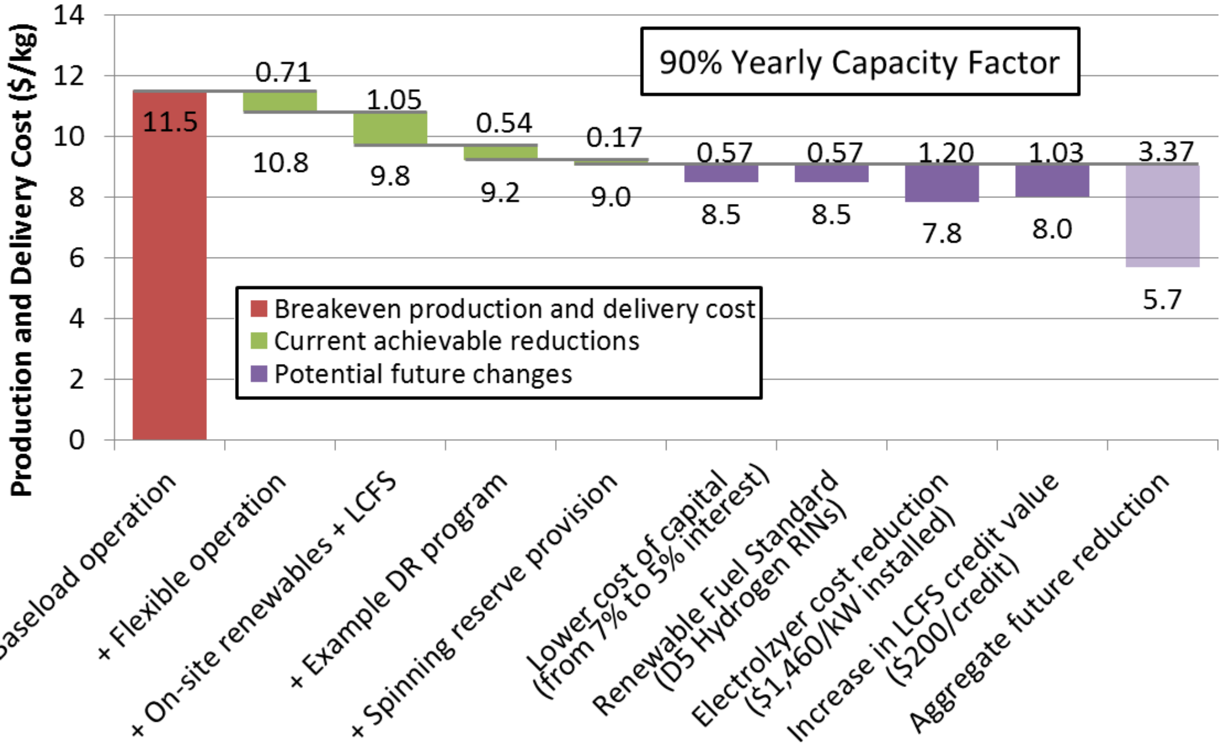

Figure ES-1. Summary cost impact of electrolytic hydrogen production for use in FCEVs with truck delivery (average across all IOUs)

Currently achievable reductions account for 21% and future potential reductions an additional 29% (Figure ES-1). Combing both current and future changes results in a hydrogen cost reduction of 51%. In comparison, reductions in the cost of capital and equipment cost for steam methane reforming (SMR) systems result in a 2.3% production and delivery cost reduction, while if the price of natural gas doubles it will increase the SMR hydrogen production and delivery cost by 20%.

Flexible operation and more active participation in electricity markets for electrolyzers have the potential to provide a reduction in the cost of hydrogen from electrolysis. The cost reduction can be experienced with no impact on the hydrogen supply to customers. Additionally, there are a variety of future opportunities to further reduce the cost for these systems. Some of the future opportunities, including new utility rates and energy market participation, were not quantified, while RFS eligibility, LCFS credit value, cost of capital, and system cost reductions were considered.

Summary of Scenario Results

Four main scenarios and a variety of sensitivities are examined. Each sheds light on the important factors that affect economic competitiveness of electrolyzers and, more generally, flexible demand response devices. The overall hydrogen costs projected for each scenario (without considering the future reductions shown above) are compared in Figure ES-2. The first bar represents the default cost without changing electrolyzer operation (i.e., baseload) and the other bars represent scenarios 1–4. Scenario 1 and 2 represent hydrogen production for FCEV

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vehicle fuel and include delivery by truck or pipeline. While the value for FCEV fuel is high, presently there is limited demand for these options. As the hydrogen station network in California continues to develop the demand for hydrogen will increase. Also, the LCFS credit for FCEV pathways is the highest. Scenario 3—renewable hydrogen for refineries—represents a market with a large existing hydrogen demand and need for carbon intensity reductions. While there is an LCFS pathway for refineries, the renewable content must be greater than 38% to receive credits. The refinery pathway cannot take advantage of vehicle efficiencies in their credit calculation because the slightly more renewable gasoline is used in a conventional gasoline vehicle, while FCEV pathways have higher vehicle efficiency and thus lower carbon intensities. The fourth scenario examines the opportunity to directly inject hydrogen into the natural gas pipeline. There is an opportunity to receive LCFS credits by blending the hydrogen in compressed natural gas (CNG) vehicles to lower their carbon intensity. The natural gas pipeline would allow electrolyzers to access a large market into which they can sell their hydrogen, but there are two things that limit the benefit of this scenario. First and most importantly, the sale price for hydrogen as a heating fuel is around one-tenth that of selling the hydrogen for use in FCEVs, as shown in Figure ES-2 (red dashed line). The second limiting factor is that the LCFS credit for the natural gas vehicle pathway is small, so apart from reducing the energy and demand charge there is no significant LCFS value that comes from producing renewable natural gas for CNG vehicles. In addition to the LCFS there may be additional value from the consumers or the regulators for producing a renewable fuel. This value is unclear and will impact the hydrogen sale price. An illustrative example is shown in Figure ES-2 (black dotted line).

Scenarios 1 and 2 present the most compelling cases for renewable electrolysis and each have different positive and negative attributes. On account of the higher LCFS value for FCEV fuel and lower delivery costs, scenario 2 is the most cost effective configuration.

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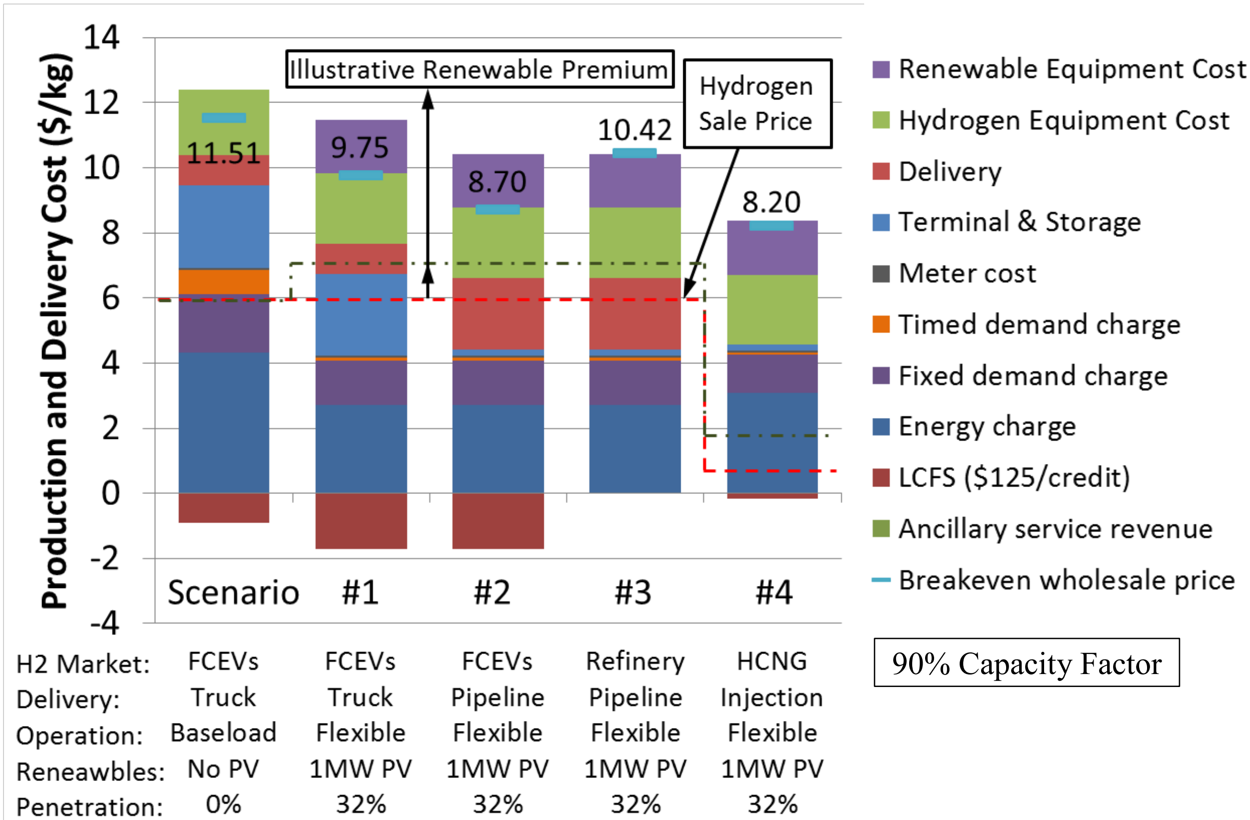

Figure ES-2. Cost components for hydrogen production scenarios

Summary of Locational Value

This study also explored the specific locations across California that yield the lowest cost hydrogen production. The cost of electricity is the single largest cost component for electrolysis systems, followed by the compression, storage and delivery costs then equipment costs. Before discussing electricity costs, we will review the locational importance of the other items. Equipment cost, LCFS value, storage and compression have limited dependence on the location selected but delivery has a dependence on location. The further the hydrogen production is from the demand the higher the costs, which is also strongly dependent on the method of delivery. This report relies on the Hydrogen Delivery Scenario Analysis Model (HDSAM) to produce delivery costs and therefore considers only one value for delivery within each of three cities. As a result a more detailed locational analysis is needed to understand the trade-offs for potential revenue and delivery costs.

For utility rate schedules, Southern California Edison (SCE) has the lowest average electricity rates including energy and demand charges, followed by PG&E and then San Diego Gas and Electric (SDG&E). In addition to utility rates, ancillary service values are higher for SCE and SDG&E territories and lower for PG&E territory. The last component that has an impact on locational value is the nodal energy prices. While demand response devices can participate in system operator day-ahead and real-time energy markets, the current baseline methodology essentially limits participation to high energy price hours. The average nodal energy prices for

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2015 were calculated across California. This provides a qualitative estimate of areas that would provide high energy market value for demand response devices. The San Francisco Bay area extending from the San Francisco peninsula to San Jose in PG&E service territory has the highest average nodal energy prices. The second area is the Los Angeles and Orange County regions in SCE territory, and the lowest average nodal energy prices are found in SDG&E territory.

Siting in SCE with low utility rates and high ancillary service value is the most beneficial. The second best area to site a renewable electrolysis system is in PG&E territory, which has the second lowest utility rates and access to potentially higher average energy market prices. This may become more relevant as the system operator participation and baseline methodology for demand response evolves to allow for more frequent participation in energy markets. Lastly, SDG&E has the highest utility rates and the lowest average nodal energy market prices, so based on this analysis SDG&E territory is presently the least valuable location for an electrolysis system.

Summary of Sensitivities

In addition to the four scenarios, there are many aspects of system design that must be considered when installing a flexible electrolysis system. Sensitivity analyses are used to determine the trade-offs for design and operation decisions. Sensitivities are performed for (1) the extent of electrolyzer flexibility that is economically favorable, (2) the value of accessing curtailed renewable energy, and (3) renewable generation sizing considerations and electrical connection.

Typical electrolyzers operate at nearly full hydrogen output every day. Reducing the amount of hydrogen produced each day enables the electrolyzers to access lower cost electricity by avoiding high priced energy and demand charges. However, lower hydrogen production means the costs must be spread over less revenue from the sale of hydrogen. Capacity factor is the measure of actual production compared to the maximum possible production for the entire year. Given current utility rates, the optimal capacity factor was determined to be 90% with and without renewables. Ninety-five percent does not allow for sufficient flexibility to avoid high electricity costs, and 80% and below cannot adequately amortize the capital costs, resulting in higher cost per kilogram of hydrogen.

Excess generation from renewable energy that might be curtailed is a concern in California. If the electrolyzer is at the correct location and has the correct agreements established to take advantage of this low cost energy it could provide a further reduction in energy cost; however, the number of hours that will be available in the future is unclear. If around 100 of the hours (1.2%) provided free energy for producing hydrogen, the overall cost would reduce $0.08/kg. Similarly, around 10% free energy would reduce the cost of hydrogen by $0.23/kg. There is a lot of uncertainty regarding the number of hours and total energy available, not to mention potential competition for that electricity, which will increase the cost for that energy. For these reasons, establishing a near-term business case based on the availability of excess renewable generation is not likely and instead should be considered as complementary to the other techniques detailed in this report.

The LCFS credit provides a valuable incentive to encourage the production of renewable hydrogen. In addition, renewable generation that is on the same utility meter enables TOU energy and demand charge reductions. However, to produce 100% renewable hydrogen an electrolyzer has to have access to roughly three times its installed capacity of solar or wind generation. This presents two challenges. First, since net metering only applies for renewable installations less than 1 MW, the electrolyzer has to be sited at a facility with a larger electricity load that can absorb the additional renewables. The second challenge is the desire to locate near the hydrogen demand areas versus the facility footprint necessary to support megawatts of renewables. One option explored in this report is to produce hydrogen with islanded (off-grid) renewables. This ensures 100% renewable production, but in order to assure constant hydrogen supply, islanded renewables require significant hydrogen storage capacity to compensate for weekly and seasonal electricity fluctuations. In most of the scenarios examined, roughly equal parts of hydrogen production and renewables provide the most favorable cost (e.g., 1 MW electrolyzer, and 1 MW wind or solar).

Recommendations for State and Federal Agencies

Based on all of the findings from this report, specific recommendations to support greater implementation of grid-integrated electrolysis equipment have been developed for state and federal agencies. Each item is listed below followed by the relevant organization(s).

- Continue activities to lower barriers to demand response (DR) participation in electricity markets, and address methods for verifying response (10-in-10 baseline method) and enabling daily use for highly flexible resources. (California Public Utilities Commission [CPUC], CAISO)

- Explore creation of dedicated electricity rate for electrolyzers. Plug-in electric vehicles rate can be used as a starting point for designing utility rates that incentivize highly dynamic operation of electrolyzers. (CPUC, utilities)

- Continue to evolve carbon credit markets. The LCFS credit in general, and in particular pathways including the 100% renewable and the refinery pathway, are good examples of developments that expand the opportunities for electrolysis while maintaining fairness for carbon intensity reductions. (ARB)

- Encourage technology advancement and demonstrations, when appropriate, to prove the value for variable operation of electrolysis to support the grid. This report details several near-term techniques for reducing the cost of hydrogen production from electrolysis; however, very few installations are applying any of these advanced strategies to reduce the operation costs of their equipment. Furthermore, equipment has been designed and research has been performed under the assumption that electrolysis should operate nearly constantly to amortize the capital costs as quickly as possible. With the availability of low-cost electricity for consumption during certain periods, the perception of constant operation of electrolysis equipment should be challenged. (CEC, DOE)

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Highlights

Flexible operation of electrolysis systems represents an opportunity to reduce the cost of hydrogen for a variety of end uses while also supporting grid operations, thereby enabling greater renewable penetration. California is an ideal location to realize that value on account of growing renewable capacity and markets for hydrogen as a FCEV fuel, in refineries, and in other end uses. Shifting the production of hydrogen to avoid high-cost electricity and participation in utility and system operator markets, along with installing renewable generation to avoid utility charges and increase revenue from the LCFS program, can result in around $2.5/kg (21%) reduction in the production and delivery cost of hydrogen from electrolysis. This reduction can be achieved without impacting the consumers of hydrogen. Additionally, future strategies for reducing hydrogen cost were explored and include lower cost of capital, participation in the RFS program, capital cost reduction, and increased LCFS value. Each strategy must be achieved independently and each could contribute to further reductions. Using the assumptions in this study, the authors found a 29% reduction in cost if all future strategies are realized. Flexible hydrogen production can simultaneously improve the performance and decarbonize multiple energy sectors. The lessons learned from this study should be used to understand near-term cost drivers and support longer-term research activities to further improve cost effectiveness of grid-integrated electrolysis systems.

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1 Introduction

Increases in clean and renewable energy along with goals to decrease greenhouse gas and criteria pollutant emissions are helping to bring about an evolution of the entire energy system. We are seeing new generation technologies for electricity, new vehicle technologies, and new focus on sustainability all while trying to provide low cost and reliable electricity, gas and transportation services to customers. In so doing, there are unique challenges that arise and there is an unprecedented level of interdependence between each sector. With more variable generation, the electric sector experiences greater needs for system flexibility and sufficient capacity as well as greater concern for overgeneration. Energy sectors are experiencing increasing pressure to provide low carbon options. In particular, the transportation sector is experiencing significant changes both in the mixture of vehicles and also the infrastructure needed to fuel those vehicles.

Hydrogen systems, namely electrolyzers and fuel cells, have the ability to integrate multiple sectors in new and unique ways. This can positively impact system flexibility, emissions, and achievable renewable content for each sector. However, combining multiple sectors presents a challenge to assess the value and potential impact for sectors that are largely treated separately from operations and regulatory perspectives.

There is a need to better understand the business models for hydrogen systems that will be economically favorable. There are several examples of hydrogen systems supporting renewable integration in Europe (European P2G Platform, 2016); however, there are limited business case assessments available. Additionally, the economic and regulatory climates are different in each region, therefore there is a need to perform such a study specific to the conditions in California.

California has shown its commitment to hydrogen and fuel cell technologies. As part of the California Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program, California is actively funding hydrogen station development. In addition, Senate Bill 1505 requires that hydrogen for state-funded fueling stations is produced from at least 33.3% eligible renewable energy.

The goal of this work is to assess the business case of hydrogen systems for near-term applications in specific locations within California. The operation of an electrolyzer as a demand response device can be used to support the electric sector (e.g., support grid operations and reduce curtailment), while the hydrogen produced can be used for a variety of end uses, including transportation fuel, heating fuel for heating and cooking, and industrial applications. Because of the wide variety of potential applications several specific areas will be highlighted. Each of the following applications utilizes electrolyzers that can produce renewable or non-renewable hydrogen depending on the input electricity: (1) hydrogen production to provide a transportation fuel for fuel cell electric vehicles (FCEV), (2) hydrogen production to be sold as a heating fuel, and (3) hydrogen production for sale as an industrial supply gas in a petroleum refinery, ammonia production facility, or other industrial process.

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2 Hydrogen System Configurations

With unique flexibility to integrate multiple sectors, hydrogen systems represent a valuable set of technologies to address energy and environmental challenges. Figure 1 depicts how hydrogen technologies can integrate the electric grid, natural gas grid, transportation and industrial gas supply. Hydrogen can be produced from a variety of equipment, most notably an electrolyzer or a steam methane reformer (SMR). Hydrogen can be used in an even broader set of technologies including a stationary fuel cell or combustion device, fuel cell vehicle, industrial application, or the hydrogen can be methanized or injected directly into the natural gas pipeline. Previous studies have also shown that electrolyzers, fuel cells, or combustion devices can provide additional service to the grid or for energy management at a customer facility (Eichman, 2014; CHBC, 2015).

This study focuses on power-to-gas and power-to-hydrogen, and does not focus on power-to-power. Power-to-gas involves using electricity to produce hydrogen then, as mentioned above, methanizing or directly injecting it into the natural gas system. Power-to-hydrogen involves producing hydrogen from electricity and using that hydrogen in a variety of end uses, including transportation or industrial processes. Power-to-power resembles a battery and involves storing electricity as hydrogen for later conversion through a fuel cell or combustion device back to electricity.

While power-to-power represents a valuable configuration to provide long-duration storage (days+), because hydrogen can be stored in large underground reservoirs similar to natural gas, previous studies have shown economic challenges with power-to-power hydrogen storage systems (Eichman, 2016). Therefore, the focus of this report is on power-to-hydrogen (i.e., electricity to hydrogen that is sold as a vehicle fuel or industrial gas) and power-to-gas (i.e., electricity to hydrogen that is injected into the pipeline). Steam methane reforming is included for comparison purposes.

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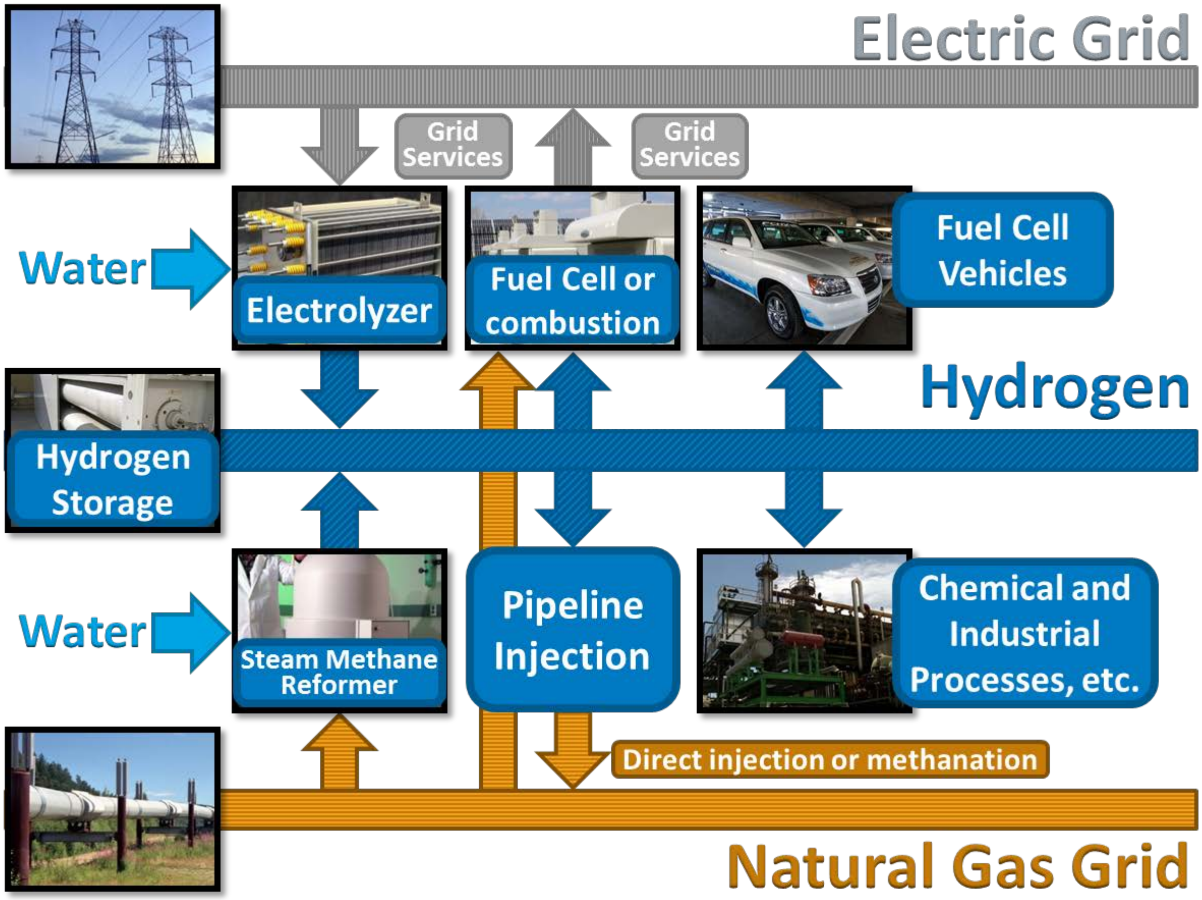

Figure 1. Hydrogen technology configurations

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3 Methodology

Results for this report are developed first by collecting the necessary electricity, gas, incentive, and equipment cost data. Next, the data are assembled into a variety of scenarios with several sensitivities. Using an operations optimization model, the maximum revenue is calculated and combined with annualized costs to determine the economic competitiveness for each scenario. Each step is described in greater detail below.

3.1 Information Collection

Data required to perform this analysis include electricity and natural gas rate schedules, renewable generation profiles, nodal energy market price data, ancillary service price data, hydrogen production equipment cost values, renewable generator cost values, and the cost for compression, storage, and delivery of hydrogen.

The input data have a variety of temporal resolutions. For instance, natural gas and electricity bills are sent to customers each month, and while the monthly natural gas consumption is sufficient for the sale of gas, electricity rates can have structures that require several hourly bins or even sub-hourly data. Additionally, the resolution depends on the electricity markets that are explored and the availability of renewable data. As a result, hourly resolution for an entire year (2015) was selected for this analysis. We recognize that the electricity demand charges are calculated based on 15-minute periods but because electrolyzers can respond to load changes on the order of seconds (Eichman, 2014), it is assumed that hourly resolution is sufficient.

3.1.1 Electricity and Natural Gas Rate Schedules

Based on the location of an electrolyzer facility in California, there are several opportunities for receiving electrical service. There are six investor-owned utilities (IOUs), nearly 50 publically owned utilities, four rural electric cooperatives, and three community choice aggregators (CCA). Each of these groups provides electricity service to customers at specified rates. For this study we focus on the three major IOUs: Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E).

There are a number of utility rate options that are available for each customer and that vary by the type of customer (e.g., residential, commercial, industrial), the size of the facility, and the resources and needs of the facility.

While there are many cost items that go into determining the cost of electricity, there are very similar techniques used by the IOUs to charge for electricity service. There are several classes of rates that a customer can choose (depending on availability): a flat fee based on the energy consumption and maximum demand; a time-of-use (TOU) rate, which is based on the energy and maximum demand during different time periods (e.g., peak, off-peak, mid-peak); and real-time pricing, which still has charges based on the maximum demand but also includes hourly energy prices instead of multi-hour bins. For this study we focus on TOU rates. An example of the hourly breakdown of a utility rate for SCE is shown in Figure 2.

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Hour of the day Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1
2	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1
3	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1
4	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1
5	1	1	1	1	1	1	1	1	2	2	2	2	3	3	3	3	3	3	2	2	2	2	2	1
6	1	1	1	1	1	1	1	1	2	2	2	2	3	3	3	3	3	3	2	2	2	2	2	1
7	1	1	1	1	1	1	1	1	2	2	2	2	3	3	3	3	3	3	2	2	2	2	2	1
8	1	1	1	1	1	1	1	1	2	2	2	2	3	3	3	3	3	3	2	2	2	2	2	1
9	1	1	1	1	1	1	1	1	2	2	2	2	3	3	3	3	3	3	2	2	2	2	2	1
10	1	1	1	1	1	1	1	1	2	2	2	2	3	3	3	3	3	3	2	2	2	2	2	1
11	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1
12	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1

Figure 2. Time-of-use rate structure example for SCE TOU8 (1=off-peak, 2=partial-peak, 3=peak)

For TOU rates, the electricity bill will contain many items, including several types of charges: a charge for energy, demand, and meter installation, maintenance, etc. The energy charge is based on the electricity consumption during a given time period ($/MWh). Demand charges are assessed based on the maximum consumption during any 15-minute interval for an entire month. There are two types of demand charges: fixed, which is based on all 15-minute intervals for the month, and timed, which has a different price for each of the time periods ($/MW-month). The meter charge is a fixed cost each month ($/meter/month). Each of these cost components is considered and described in more detail in later sections.

Rate schedules for the three major California IOUs are included for the year 2015. Table 1 provides a summary of the electricity rate schedules considered and Table 2 provides a summary of the natural-gas rate schedules. There are different levels of connection for each utility, which correspond to a certain voltage and the equipment that the utility must provide for the customer to take electric service. Additionally, there is a variety of rates that are applicable for electrolyzer systems. We target 1 MW as the power level for rate schedules and select both renewable and non-renewable schedules. A summary of the selected schedules is shown in Table 1. PG&E and SCE utility rates include the commodity cost as well as the transmission and distribution (T&D) demand charges. SDG&E has separated the bills into general service (ALTOU or DGR) and commodity (EECC-CPP-D).

All of the rates considered in this report are TOU rates. There may be additional opportunities to improve electricity cost reductions beyond the selected TOU rates, made available by pursuing other TOU rates or real-time price (RTP) rates. For RTP rates, customers stay on bundled service but can reduce their rates with operation that is more integrated with utility needs. Pursuing RTP rate schedules is potentially another way to reduce electricity costs and should be considered by plant operators. Due to the complexity of implementing each rate schedule, only the items in Table 1 are analyzed in this report.

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Table 1. Summary of electricity rate schedules included in the analysis

Utility Area	Connection	Utility Rate	Capacity	Renewable Limits
PG&E	Secondary (<2.4kV) Primary Transmission	E20 E20R	≥1,000kW ≥1,000kW	 ≥15%
SCE	Secondary (≤2kV) Primary (2 – 50KV) Transmission (>50kV)	TOU8B TOU8R	≥500kW ≥500kW	 ≥15%
SDG&E	Secondary Primary Transmission	ALTOU[3] + EECC-CPP-D DGR + EECC-CPP-D	≥500kW and <12MW ≥500kW and <2MW	≥10%

PG&E serves gas to the majority of customers in their territory, while Southern California Gas Company provides gas to SDG&E customers and most of SCE customers. Rate schedules were selected for each region and 2015 values were used.

Table 2. Summary of natural gas rate schedules included in the analysis

Utility Area	Utility Rate	Description
PG&E	GNR2	Large commercial customers (2015)
SCE and SDG&E	GN-3	Core non-residential customers (2015)

3.1.2 Utility Demand Response Programs and Usage Data

In addition to the charges on a utility bill, there are several options to reduce electricity costs by participating in utility demand response (DR) programs. Each utility has a similar collection of programs and establishes their own value for these programs. Table 3 provides a summary of key programs and program value for each of the major IOUs. These programs provide an incentive for reducing demand. Programs include base interruptible program (BIP), capacity bidding program (CBP), demand bidding program (DBP), critical peak pricing (CPP) or peak day pricing (PDP), aggregator managed profile (AMP), and automated demand response program (ADR). There are other demand response programs not summarized in Table 3 including optional binding mandatory curtailment (OBMC), permanent load shifting (PLS), and scheduled load reduction (SLRP). Programs can, in some cases, be combined with other programs. As an example, customers participating in CBP can also participate in OBMC, DBP, or SLRP depending on the CBP market to which they apply. Interested parties should also consider those programs as well when determining the right program(s) that suit their ability.

[3] SDG&E utility rates include a general service item (e.g., ALTOU) which is predominantly transmission, and distribution costs and commodity service (e.g., EECC-CPP-D) which is predominantly energy costs.

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Table 3. Summary of demand response programs available from the major IOUs in California

Demand Response Program	Description	Value
Base Interruptible Program (BIP)	Load reduction when the CAISO issues an event notice on a day-of-basis. ≤10 events per month or ≤180 hours per year and a maximum hours/event[4]. A penalty is charged if the device does not respond as prescribed during an event.	PG&E: $8-9/kW/month SCE: $1.12 to 23.17/kW/month[5] SDG&E: $2 (winter) or $12/kW/month (summer)
Capacity Bidding Program (CBP)	Event based demand reduction program. The reductions are from 1 to 8 hours and ≤30 hours/month. A penalty is charged for not achieving the specified capacity reduction.	PG&E: $3.04 to $24.81/kW/month[6] SCE: $1.13 to $22.46/kW/month SDG&E: $2.43 to $28.65/kW/month
Demand Bidding Program (DBP)	Event-based demand reduction program. The customer receives an incentive based on the energy reduced ($/kWh) during an event into which they have bid. There is no penalty for not providing a reduction during an event.	PG&E: $500/MWh SCE: $500/MWh SDG&E: $500/MWh
Critical Peak Pricing (CPP) or Peak Day Pricing (PDP)	This program gives customers lower energy prices or demand charges throughout the year during non-event hours but a high price during event hours to encourage load shifting.	PG&E: $1.19 to $6.50/kW/month timed demand charge reduction for E20[7] SCE: Reduction depends on rate option selected SDG&E: $0.3/MWh reduction for AL-TOU[8]
Aggregator Managed Profile (AMP)	Customers work with demand response aggregator to either use an existing aggregator program or develop a unique program to suit their needs.	Established by aggregator
Automated Demand Response Program (ADR)	Automatically reduce energy use during demand response events. Must enroll in PDP, AMP, DBP, or CBP.	PG&E: $200 to $400/kW (one-time)[9] SCE: $300/kW (one-time) SDG&E: $300/kW (one-time)

Many of the programs require different behavior during event periods. These events are triggered by a variety of conditions including California Independent System Operator (CAISO) load

[4] PGE: 4 hours/event; SCE: up to 6 hours/event.
[5] Value depends on the BIP options and reflects time of use (e.g., summer on-peak, summer mid-peak and winter mid-peak).
[6] The value depends on the duration provided (1–4, 2–6, or 4–8 hours), the month (PGE and SDG&E available only May to October), and the selection of notice (day-ahead or day-of notice).
[7] Reduction range is only for the summer and for part-peak (low values) and peak (high values). The penalty is $1,200/MWh for all operation during an event. There are typically 9–15 event days per year.
[8] Reduction applies for on-peak and semi-peak but not off-peak. The additional event adder is between $1,100/MWh and $1,158/MWh depending on the service voltage.
[9] $350/kW for heating, ventilation, air conditioning, and refrigeration HVAC/R; $400/kW for advanced lighting; and $200/kW for all others.

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forecast (>43,000MW), CAISO alert notice, high-temperature forecast, utility forecast of generation resources inadequacies, CAISO, or utility T&D reliability need or requirement of high heat-rate generation (>15,000 BTU/kWh). Some programs have limitations on the number of events that can be called and others do not. While there are different strategies, the overarching goal is to incentivize customers to reduce generation during congested periods and locations or for other grid events.

The revenues received from program participation depend on the program incentive structure—energy ($/MWh), capacity ($/MW), etc.—and if the incentive is provided every month independent of use, or if the revenue is based on the number of events called. Establishing those properties along with the capacity available to bid is necessary for determining the potential revenue as well as the potential utility bill impacts (e.g., increased demand charge caused by an event).

SCE provides historical demand response program usage data on their website[10]. Table 4 shows historical usage from 2011 to 2015 for four of the programs. BIP, CPP and DBP are consistent in the number of events per year, while the CBP fluctuates more and has the highest number of events. Most of the events (74%) are focused between July and October. All of the DBP events are 8 hours long, the CPP events are 4 hours long and the only BIP event is 2.5 hours long. Lastly, all of the events in 2015 started between noon and 6 p.m., with longer events starting earlier (e.g., all DBP events start at noon). Section 8.6 combines the program value with the event criteria to establish the expected revenue and potential for program participation.

Table 4. Summary of SCE historical demand response program usage

Program	Product	2011	2012	2013	2014	2015
BIP	BIP	1	1	1	1	1
CBP	CBP 1-4 hour Day-ahead	19	12	28	26	63
	CBP 1-4 hour Day-Of	3	7	4	15	75
	CBP 2-6 hour Day-ahead	10		22	11	25
	CBP 2-6 hour Day-Of	2	7	4	13	36
	CBP 4-8 hour Day-ahead			10		
CPP	Commercial	12	12	12	12	12
	Residential	12	12	12	12	12
DBP	DBP Day-ahead	6	8	5	6	10

3.1.3 California Renewable Generation Data

Using renewable electricity enables the production of renewable hydrogen. We use photovoltaic (PV) and wind profiles developed by normalizing hourly historical wind and solar production data from CAISO's renewables watch.[11] These values include only large-scale solar and wind.

[10] SCE demand response event history website (https://www.sce.openadr.com/dr.website/scepr-event-history.jsf).
[11] Website for Renewables Watch (http://www.caiso.com/green/renewableswatch.html).

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For the purpose of this study we do not use distributed wind and we assume that distributed solar has the same profile as large-scale solar.

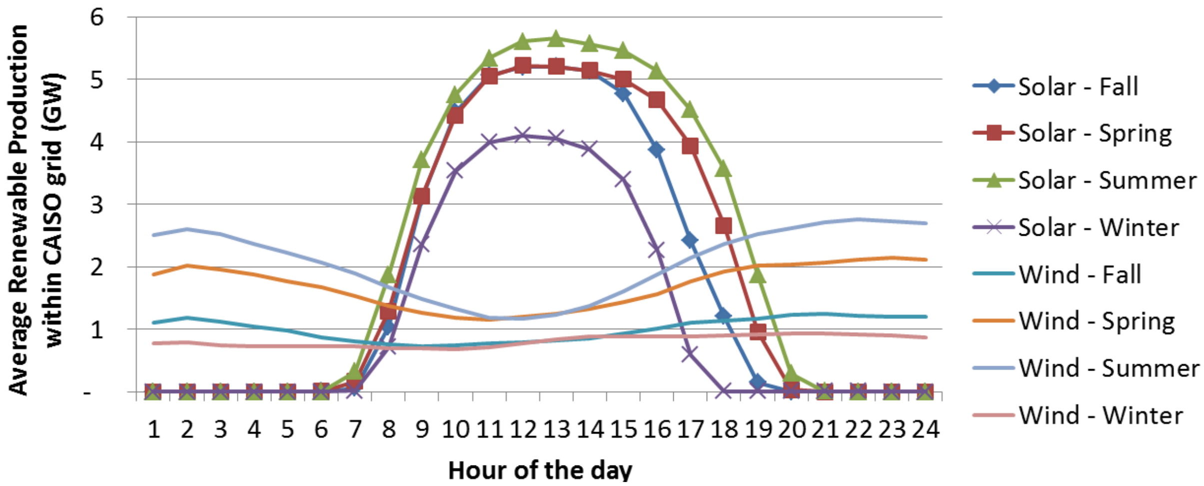

Figure 3. Average renewable production within CAISO grid for 2015 (from Renewable Watch)

Utility rates, and in particular demand charges, are calculated as the average demand for a 15-minute time period. The resolution of the profiles above is hourly and is smoothed by the aggregation of many units. We recognize that actual variations in a small solar plant will be more pronounced and its impact on an electrolyzer must be considered for an installation. For the purposes of this study we assume that electrolyzers can adjust their demand to avoid incurring greater demand charges from renewable deviations not captured in the hourly profiles. While this is a reasonable assumption based on the operating flexibility of electrolyzers, there could be implications for equipment lifetime if the electrolyzers are required to cycle more often to accommodate variations in local renewable generation.

3.1.4 CAISO Electricity Market Participation and Data

The CAISO has several opportunities for market participation of devices that do not behave as typical generators. Currently the non-generator resource (NGR), proxy demand response (PDR) and reliability demand response resource (RDRR) are options that are available for storage and demand response devices to participate in the independent system operator (ISO) markets. Additionally, the CAISO is currently pursuing an initiative called the Energy Storage and Distributed Energy Resource (ESDER) Stakeholder initiative (phase 2) to lower the barriers for grid-connected storage and distributed energy resources to participate in ISO markets.

The NGR product is largely focused on energy storage and allows participation in the energy market as well as regulation, spinning, and nonspinning reserve markets[12]. Because of the focus on storage we do not further explore NGR in this report.

This study focuses on use of the PDR. PDR and RDRR both use the same technical functionality and infrastructure for their implementation but differ in the services that can be offered as well as

[12] Find more information about the NGR here (www.caiso.com/participate/Pages/Storage) .

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the markets into which they can bid.[13] Devices bid into ISO markets as a supply resource. RDRR participates in ISO day-ahead energy markets or for reliability events in real-time but cannot provide ancillary services. PDR can bid economically into day-ahead and 5-minute real-time energy markets, and day-ahead and real-time nonspinning and spinning markets as well as residual unit commitment. Both the PDR and RDRR rely on historical data to form a baseline for energy market participation. The baseline is constructed from previous, similar days (weekday, weekend/holiday) and is used to compare what the device would have provided versus what it actually provided. Since the baseline cannot be constructed of days in which the device won a bid in the energy market, the baseline presents a challenge for devices that are very flexible and are available to participate every day. Also, unlike NGR, PDR does not allow for participation in regulation markets at present.

To encourage demand response procurement the California Public Utilities Commission (CPUC) issued a decision (D-14-12-024) that mandated that the IOUs develop a demand response auction mechanism (DRAM) pilot program. This program procures demand response capacity to provide local, system, and flexible resource adequacy resources and can also participate in CAISO energy markets through PDR or RDRR. Each year the utilities hold an auction, SCE and PG&E have a target of 10 MW of capacity in the 2017 DRAM and SDG&E has a target of 2 MW of capacity.

Historical electricity market data is available on the CAISO's Open Access Same-Time Information System (OASIS) website. We collected the 2015 ancillary service price data from OASIS, which includes hourly resolution price data for the north (PG&E) and the south (SCE and SDG&E) for four products: regulation up (RegU), regulation down (RegD), spinning (SP), and non-spinning (NR) reserves. Ancillary service prices are shown in Figure 4. The shape for spinning and regulation up has two distinct peaks, one in the morning and one in the evening. Regulation is the highest valued with a yearly average of \$5.77/MW for up and \$3.23/MW for down. Spinning is next with a value of \$3.58/MW, and nonspinning has an average value of \$0.40/MW.

[13] Find more information about the load and demand response options (www.caiso.com/participate/Pages/Load).

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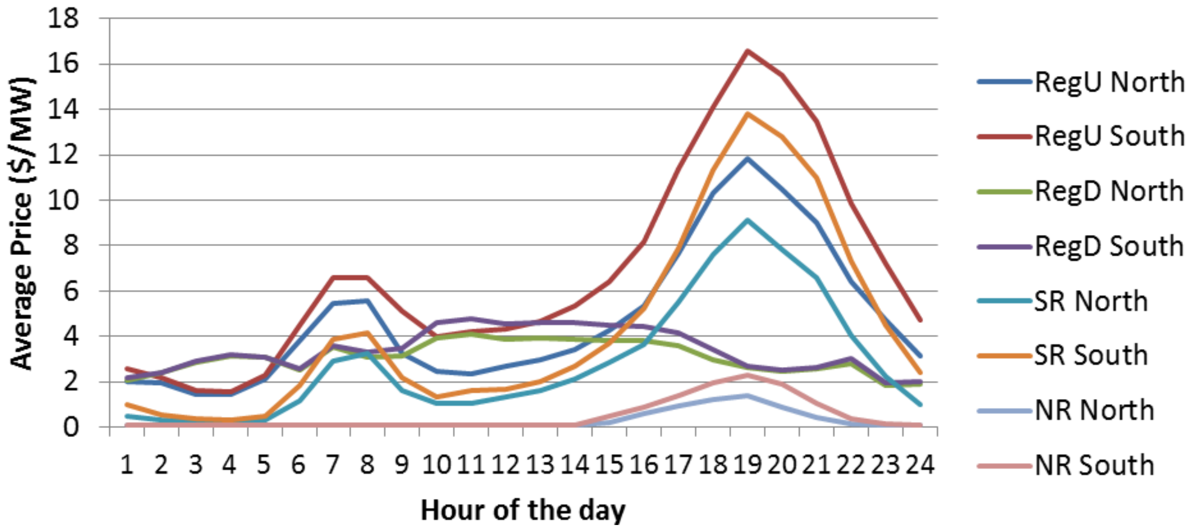

Figure 4. Average day-ahead CAISO ancillary service prices for 2015

While OASIS includes nodal energy prices it does not provide the geospatial coordinates for each node. As a result we used Ventyx electricity market data and drew day-ahead and real-time[14] price data for each load, aggregate, and zone node in California. This resulted in 2,549 nodes that have a complete set of hourly energy market prices. The distribution of prices and how those price regions relate to the current fueling infrastructure is shown in Section 8.7.7.

3.1.5 Hydrogen Production and Renewable Generator Cost Data

In addition to calculating the optimal operation profile and revenue, this analysis considers the capital investment of producing, compressing, and delivering hydrogen gas. The operational parameters required to run the optimization model are the rated power capacity, system efficiency, and minimum part-load. The range of power capacities will be described in more detail in later sections. The minimum part-load represents the lowest operating point a system can maintain before it has to shut off.

The annual cost is calculated using the equipment costs for each device (Table 5) and the methodology is described in Section 3.3. Notice that we include a capital and installation cost for renewables. Alternatively, one can look for a third party from which to purchase electricity. For this study we assume that the owner of the hydrogen system also owns the renewable generation system. A description of renewable purchasing options is described in Section 8.7.5.

[14] Real-time data is provided by Ventyx with an hourly resolution and is the average of all the 5-minute intervals within each hour.

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Table 5. Assumptions for equipment properties

Properties	Electrolyzer	Steam Methane Reformer	PV	Wind
Rated Power Capacity (MW)	0.42 – 1.0	177 – 420 kg/day	0.0 – 4.0	0.0 – 4.0
Energy Capacity[15]	4 hours 74 kg H_2	4 hours 74 kg H_2	-	-
Capital and Installation Cost ($/kW)	1,414 [a]	1,092 $/kg/day [a]	2,540 [b]	1,711 [c]
Fixed O&M ($/kW-year)	69.7 and 25.0 (replacement) [a]	4.5% of Capital [a]	0 [b]	50 [c]
Depreciation Schedule Length (years)	20 [a]	20 [a]	20	20
Interest Rate on Debt	7%	7%	7%	7%
Efficiency	61.4% lower heating value [a] (54.3 kWh/kg)	0.156 MMBTU/kg [a] 0.6 kWh/kg [a]	-	-
Minimum Part-Load	10%	100%[16]	-	-

[a] NREL - H2A Model version 3.0 (H2A Hydrogen Production Model, Version 3., 2015)

[b] DOE - Photovoltaic System Pricing Trends, 2014 (Commercial PV) (Feldman, et al., 2014)

[c] NREL - Annual Technology Baseline, 2015 (Utility-scale wind) (Sullivan, et al., 2015)

Compression, storage, and delivery costs are calculated using the Department of Energy's Hydrogen Delivery Scenario Analysis Model (HDSAM version 3.0). Compressed gas delivered by truck and pipeline are delivery options considered for Los Angeles, San Francisco, and San Diego and used to represent each of the investor owned utilities, SCE, PG&E and SDG&E, respectively. Values were calculated assuming a combined urban and rural hydrogen market with 5% market penetration and low-volume production estimates to represent a near-term market scenario more closely. Figure 5 shows the resulting compression, storage, and delivery (CSD) cost components by city and delivery method.

[15] A sensitivity analysis is performed on the storage duration. The capacity is varied from no storage up to 168 hours (3,094kg) to explore the impact on cost of production.

[16] Steam methane reformers have a minimum part-load point far below full power. However, for this analysis, because the consumption of electricity is small and the price of natural gas does not change significantly (i.e., changes each month), we assume that there is negligible value in electricity markets from modulating the output of an SMR unit and hold its output constant.

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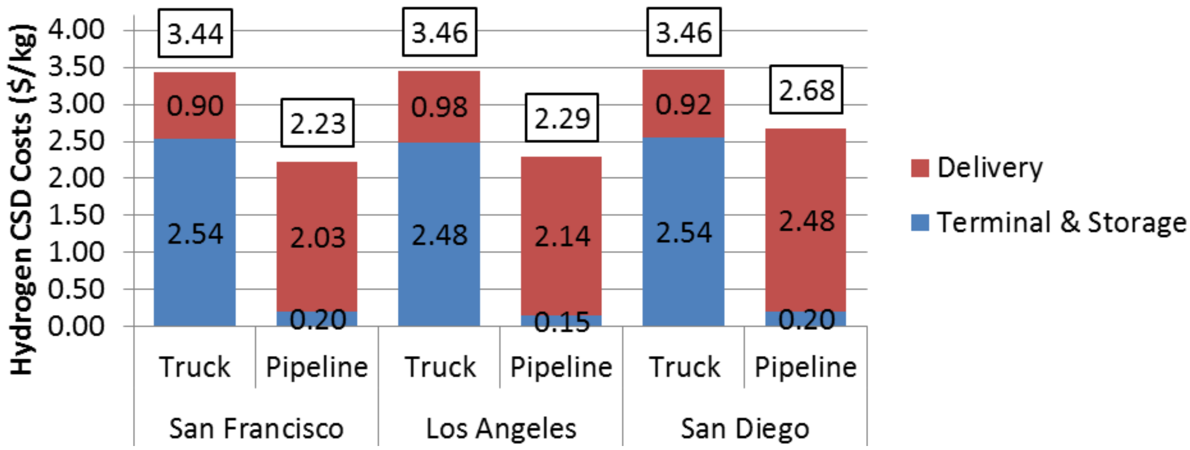

Figure 5. Compression, storage and delivery costs from HDSAM

3.2 Optimizing Revenue and Device Operation

An operations optimization model is used to determine the maximum revenue achievable for each scenario, described in Section 4. The mixed-integer program is coded in GAMS. This model has been used previously for hydrogen grid integration activities and is described in detail (Eichman, 2016). The model has also been used for exploring general energy storage valuation (Eichman, 2015). Additions to the model include greater detail for utility service. A flowchart for the model is shown in Figure 6. Inputs include the cost of retail electricity service, revenue from ancillary service markets, hydrogen demand requirement, and operational parameters. Each is described in greater detail below. The cost or revenues from each input value is optimized to achieve the maximum revenue considering the purchase cost of electricity, the value of hydrogen and any additional revenue from providing reserves.

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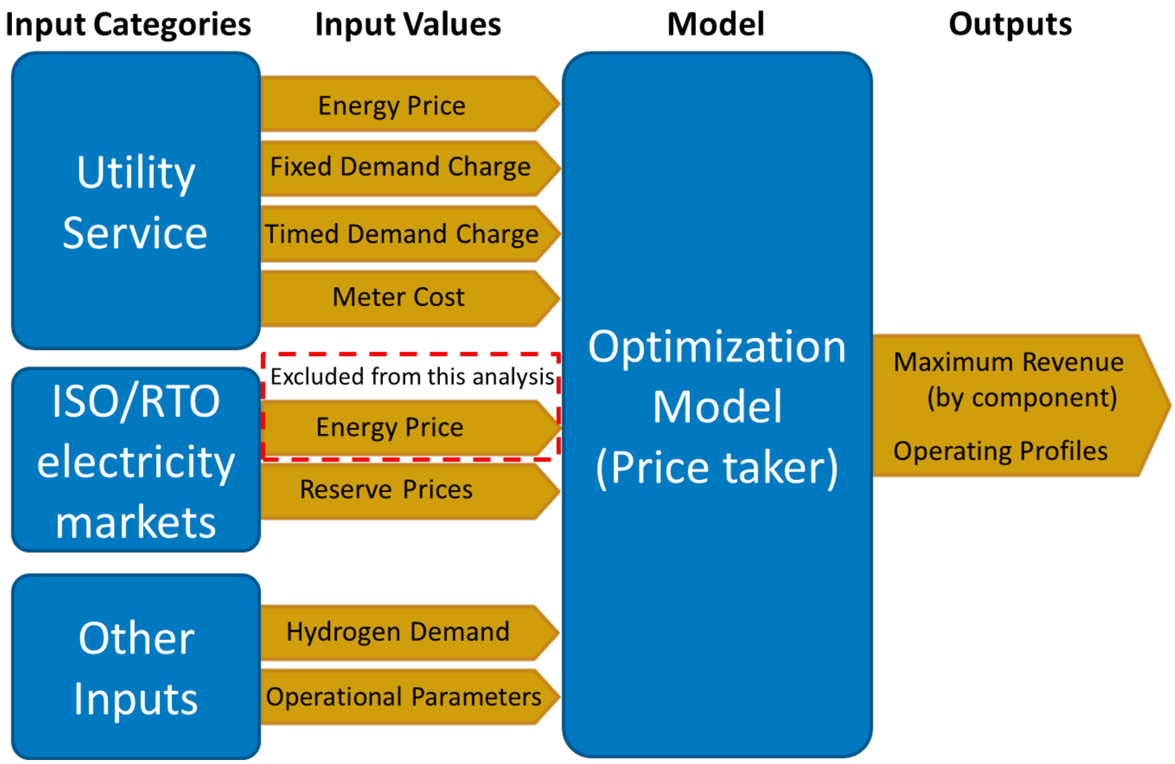

Figure 6. Optimization model flowchart

For each rate schedule, bundled utility electricity service comprises a price for energy ($/kWh), a fixed demand charge ($/kW-month), a timed demand charge ($/kW-month), and the cost for utility meters ($/meter/month). Other items are often included such as a cost for power factor adjustment and special pricing opportunities (e.g., peak day pricing or critical peak pricing that incentivize peak usage reduction). In addition, each rate schedule includes a number of conditions under which the rate schedule applies. Energy prices are assessed for every unit of energy consumed, while demand charges are assessed based on the maximum monthly demand for the entire month (fixed) or for select time-slices within that month (timed). Lastly, the meter cost is to rent and maintain the revenue grade meter that the utility provides. The complete rate schedules are freely available on the website for each gas or electric utility.

This analysis includes consideration for electricity markets. While we discuss the opportunities for entering day-ahead and real-time energy markets, we only include ancillary service market revenue in the analysis. In order to qualify for California electricity markets, demand response customers must create a baseline that is built around several days of recent operation data for the device. Inclusion of this resource baseline formulation, while technically possible to integrate into an optimization model, is heavily influenced by forecasting of both operational needs and energy prices. As a result, energy markets are not included in this analysis and should be considered for future work. Provision of ancillary services requires that sufficient capacity is available to provide the desired service and, as a result, does not require price forecasting. At present, the CAISO's PDR product allows for provision of nonspinning and spinning reserve. We explore spinning and nonspinning reserves as well as the potential for providing regulation reserves, which is not currently eligible.

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There are several other inputs into the optimization model including the hydrogen production capacity factor (CF) or utilization (e.g., 40%, 60%, 80%, 90%, and 95% of the output of a 1-MW electrolyzer with an efficiency of 54.3kWh/kg). We assume a constant hydrogen demand profile for each hour of the day and the hydrogen can be produced directly from the electrolyzer or drawn from on-site storage (e.g., when electricity prices are high). Additional parameters included in the optimization model are rated power, minimum part load, efficiency, and storage capacity.

3.3 Equipment Cost Calculations

Yearly costs are calculated by annualizing the net present cost from capital and fixed operation and maintenance costs over the lifetime of the equipment, at a given interest rate. We assume that there is no initial equity investment and no taxes are included. See Table 5 for the cost assumptions. All cost and operational parameters are selected to represent near-term values, using the same process detailed in Eichman, Townsend, & Melaina, 2016. A model flowchart depicting the cost calculation process is shown below (Figure 7).

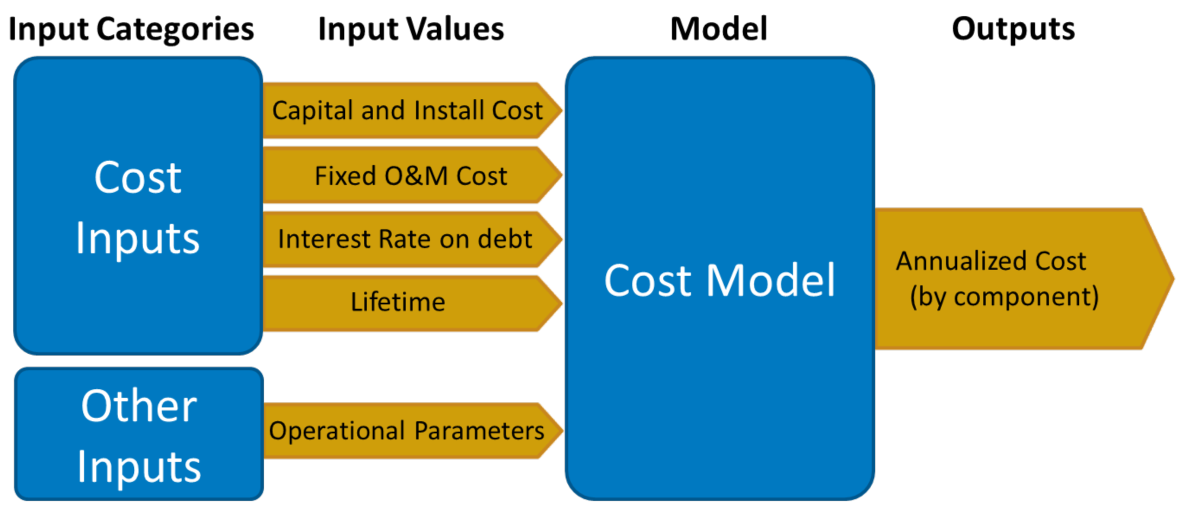

Figure 7. Cost Model flowchart

The annualized cost values are combined with the operating costs calculated by the optimization model and the compression, storage, and delivery costs (Figure 5) to determine the wholesale cost of producing and delivering hydrogen. This value does not include any profit, but rather represents the breakeven cost to operate the system.

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4 Scenarios

There is a wide variety of end uses for hydrogen including as a transportation fuel for fuel cell electric vehicles, use in industrial processes as a feedstock or for heating, and injection into the natural gas pipeline. We have narrowed the list to several examples that present near-term opportunities in California. Table 6 summarizes the scenarios considered.

Table 6. Scenarios considered for analysis

Scenario	End-Use	Delivery	Renewable Source
1	**Transportation fuel**	Truck – compressed gas	Wind or PV
2		Hydrogen Pipeline	Wind or PV
3	**Industrial gas – Petroleum refinery**	Hydrogen Pipeline	Wind or PV
4	**Injection into natural gas pipeline**	-	Wind or PV

The first scenario involves using electricity to produce hydrogen that is then used as a transportation fuel. We consider delivery via compressed gas in a truck or hydrogen pipeline. All hydrogen can be produced renewably by generating renewables on-site, purchasing renewable electricity, or purchasing renewable credits. To qualify for the Low Carbon Fuel Standard (LCFS) credit a pathway must be shown between the renewable source and sink. Therefore we assume that all renewables are either on-site or close enough to the hydrogen system to establish a physical pathway. This scenario can represent a central or distributed (if delivery is removed) hydrogen production facility to serve transportation needs. One of the challenges with this scenario is that the near-term demand for fueling stations is low, but this scenario has exceptional growth potential as the market can expand into the transportation space. This study does not discriminate between fuel cell vehicle type, meaning that these results could be applied to fuel delivered for light-duty passenger vehicles and medium- and heavy-duty vehicles.

The third scenario involves producing hydrogen and supplying it to a petroleum refinery. Hydrogen is used to process crude oil into refined fuels. Because of the large volumes of hydrogen typically required, the hydrogen is either produced on site or in some cases delivered by a hydrogen pipeline (e.g., the hydrogen pipeline in Southern California that feeds refineries and other needs). The California LCFS has a pathway for using renewable hydrogen in a refinery to reduce the carbon intensity (CI) of conventional internal combustion engine vehicles, receiving a credit in the process. The benefit of this scenario is that there is already a significant demand for hydrogen at refineries. For limited demonstrations, the existing pipeline and compression and injection equipment can be leveraged by the electrolysis equipment to reduce costs. While there is a significant demand for hydrogen in the near-term, the push for alternative fueled vehicles means that even though the existing capacity will stay, the growth potential for hydrogen for refineries is limited.

The last scenario involves injecting hydrogen directly into a natural gas pipeline, which is technically feasible in modest volumes (Melaina, 2013). There is interest in understanding the economic value of this pathway. In addition to direct injection, the hydrogen can be converted to methane using a methanation process, which combines carbon dioxide with hydrogen or by

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upgrading biogas. For this analysis we explore direct injection only. Natural gas heat content can fluctuate based on the incoming gas and must stay in an approved range. Hydrogen can be directly injected, particularly in areas with heat content closer to the upper limit, to reduce the heat content of the mixed gas. Using renewable hydrogen, direct injection, methanation, or biogas upgrading can all help to increase the renewable content of the gas system. There is a very large demand for natural gas and limited options to produce renewable gas. Unfortunately, the value of natural gas is much lower than selling hydrogen for the other scenarios. Selling natural gas at $6/MMBTU converts to $0.68/kg of hydrogen—nearly a full order of magnitude lower than the sale price for hydrogen as a transportation fuel. The other challenge is that since the natural gas providers operated within their defined limits, there is no additional value for adjusting the heating content of the natural gas system.

4.1 Parameter Space for Each Scenario

For each of the scenarios considered there is a broad parameter space to explore. Table 7 provides a summary of the set of parameters considered for every scenario. Each column is described in the subsequent paragraphs. The optimization model is run for every combination of parameters and a run is also performed for each utility rate considered (i.e., E20, E20R, TOU8B, ALTOU, DGR) and for every voltage connection level in the utility rates (i.e., secondary, primary, and transmission).

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Table 7. Parameter space for analysis

Hydrogen Production Technology	Operation Strategy	Installed Capacity[17]	Yearly Capacity Factor[18]	Storage Duration	Installed Renewables[19]
Electrolyzer	Baseload	0.42, 0.63, 0.84, 0.95, 1 MW	95%	-	0–4 MW
	Flexible	1 MW	40%, 60%, 80%, 90%, 95%	1 to 168 hours 18.4 to 3,094 kg	0–4 MW
	Flexible +Nonspinning Reserve	1 MW	40%, 60%, 80%, 90%, 95%	1 to 168 hours 18.4 to 3,094 kg	0–4 MW
	Flexible +Spinning Reserve	1 MW	40%, 60%, 80%, 90%, 95%	1 to 168 hours 18.4 to 3,094 kg	0–4 MW
	Flexible +Regulation Reserve	1 MW	40%, 60%, 80%, 90%, 95%	1 to 168 hours 18.4 to 3,094 kg	0–4 MW
Steam Methane Reformer	Baseload	177, 265, 354, 398, 420 kg/day	100%	-	0 MW

Electrolyzers can operate in a variety of configurations including “baseload,” which is the typical constant level of operation. “Flexible” systems adjust to changes in retail electricity prices to maximize their profit. The next three items include flexible operation with three different ancillary services offered in California. Each operating strategy utilizes flexible operation to avoid high electricity times but also provides ancillary services when appropriate. As discussed previously, the PDR product allows provision of spinning and nonspinning reserve but does not allow for provision of regulation reserve; however, existing products can change and new products are still being developed, so it is not unreasonable that demand response could, under the right conditions, provide additional grid services in California in the near future. As a result, regulation reserve is included to explore the relative potential of this market. Lastly, SMR is included to put the cost of electrolysis into the context of the current system. SMR is the incumbent technology for many of the same applications.

[17] Baseload electrolyzers and SMR are sized to correspond to the same hydrogen production that flexible electrolyzers produce for each capacity factor (i.e., 0.42 MW operating at 95% baseload capacity is the same as 1 MW flexibly operated to provide 40% of its hydrogen production capacity). This is because an operator would not install a 1 MW electrolyzer, then operate it at 40% power constantly; rather they would purchase a smaller electrolyzer.

[18] Measure of the amount of actual hydrogen produced versus the maximum possible production each year.

[19] Renewables are installed ranging from 0 to 4 MW and include 0, 0.5, 1, 2, 3, and 4 MWs. Renewable tariffs must have more than 10% or 15% renewable penetration, so they do not include the no-renewable case.

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The installed hydrogen production capacity and capacity factor columns are tied together. A 0.42MW baseload electrolyzer corresponds to a 1MW flexible electrolyzer with a 40% capacity factor. By varying the capacity factor of the electrolyzers we can explore the opportunities for increasing electrolyzer flexibility and potential to both reduce energy costs and increase the service provided to the grid. In the case of systems that operate in baseload there is no reason to purchase a large system and operate it at a fraction of the capacity without being able to provide any additional services. So for the baseload systems, we vary the installed hydrogen production system capacity while still operating it at a high-capacity factor.

The storage duration is varied to explore the impact of differences in electricity price reduction potential. The on-site storage tank provides a buffer from which the system can provide hydrogen at a different time than it is produced.

The last column shows the range of new renewable generation that is explored. The renewable rates (i.e., E20R, TOU8R, and DGR) must have more than 10% or 15% renewable penetration on an energy basis. Therefore the renewable rates have installed 0.5 MW to 4 MW. The 0.5 MW roughly represents the 15% renewable penetration level. The base rates include a case with no renewables, 0.5, 1, 2, 3, and 4 MW of wind or solar. We are not considering net metering as an option because it requires that the renewable installation is less than 1 MW. The 1 MW electrolyzer will always be able to use up to 1 MW of renewable power so net metering is only needed for renewable systems greater than 1 MW, which are not eligible for net metering. Therefore, net metering is not applicable for the electrolysis systems explored in this report. In order to install greater than 1 MW of renewables we propose that the electrolyzer be co-located with another large electrical load.

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5 Electrolyzer Operation

The operation profile for each hour of the year is determined using the optimization model for the set of parameters and configurations in Tables 1–7. The result is the operation that minimizes the overall costs of energy across the year. Figure 8 and Figure 9 show the operation for baseload and flexible strategy with and without PV assuming a 90% yearly capacity factor for the summer utility period (5/1/2015–10/31/2015) and winter (1/1/2015–4/28/2015 and 11/1/2015–12/31/2015), respectively. Figure 10 and Figure 11 show the same operation information only for with and without wind. Notice the flat profile for the baseload operation strategy. For the flexible strategy, the summer has peak, mid-peak, and off-peak periods so it is expected that the profile will be more erratic than during the winter, which has only two time periods—mid-peak and off-peak. With the addition of renewables, particularly PV, the electrolyzers are able to operate more during the peak periods without incurring a high demand charge or high energy cost. This is also valuable when considering the opportunity to get additional revenue from utility demand response programs.

Because of the focus on reducing peak energy and demand charges, the consumption during the summer peak is reduced, while for the winter, there is no peak for PG&E E20. On account of the renewables there is greater hydrogen production from 7 a.m. to 4 p.m. for PV. Since the wind production profile is relatively flat, the winter electrolyzer remains relatively flat as well. As a result of minimizing the costs, the potential demand response capacity is lower in the summer, when the capacity is needed for program participation and higher during the winter when it is not needed. This is an important point when considering flexible operation. The value for reducing the utility bill must offset the potential value from the demand response programs. This concept is further explored in Section 8.6.

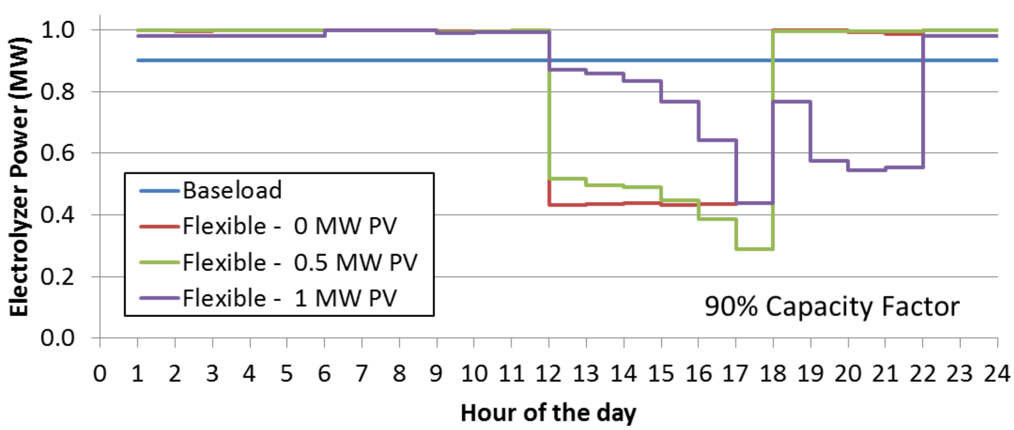

Figure 8. Average summer electrolyzer operation for PG&E E20 rate with and without PV

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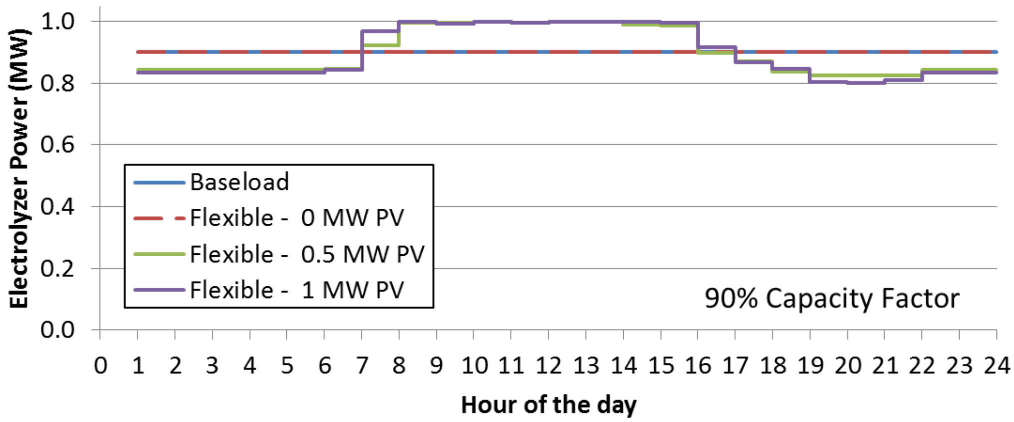

Figure 9. Average winter electrolyzer operation for PG&E E20 rate with and without PV

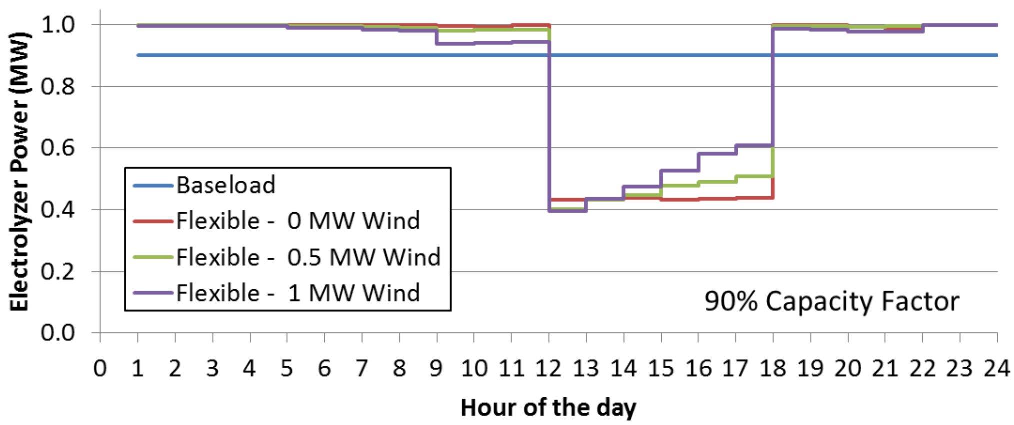

Figure 10. Average summer electrolyzer operation for PG&E E20 rate with and without wind

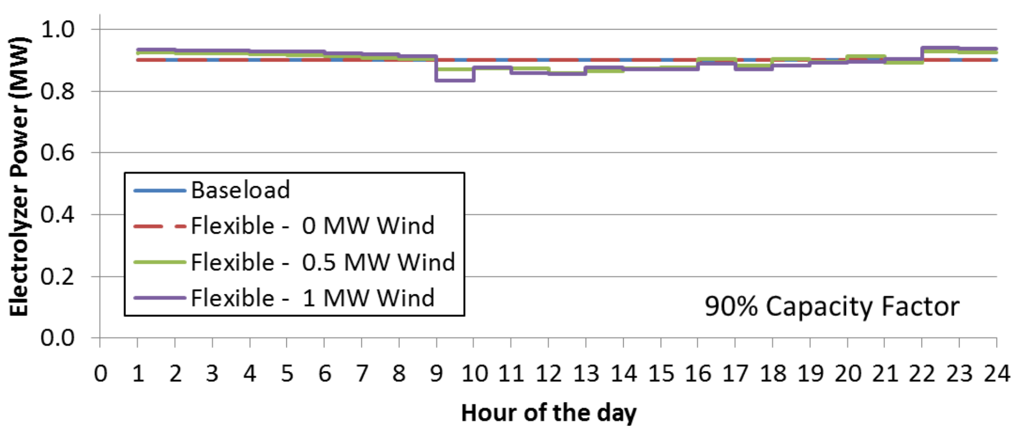

Figure 11. Average winter electrolyzer operation for PG&E E20 rate with and without wind

In addition to the operating strategy and installed renewables. capacity factor has a large impact on the operation of the equipment. Figure 12, Figure 13, and Figure 14 show the impact from various yearly capacity factors with 0, 0.5, or 1 MW of on-site renewables. With a yearly

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capacity factor less than 80% and no renewables, the electrolyzer is encouraged to turn off in the afternoon nearly every day during the summer. As the renewable capacity increases, the impact of peak summer pricing is still evident by the large-step changes in operation during mid- or off-peak periods. Additionally, with renewables the electrolyzer facility is able to provide more capacity during the day for demand response programs.

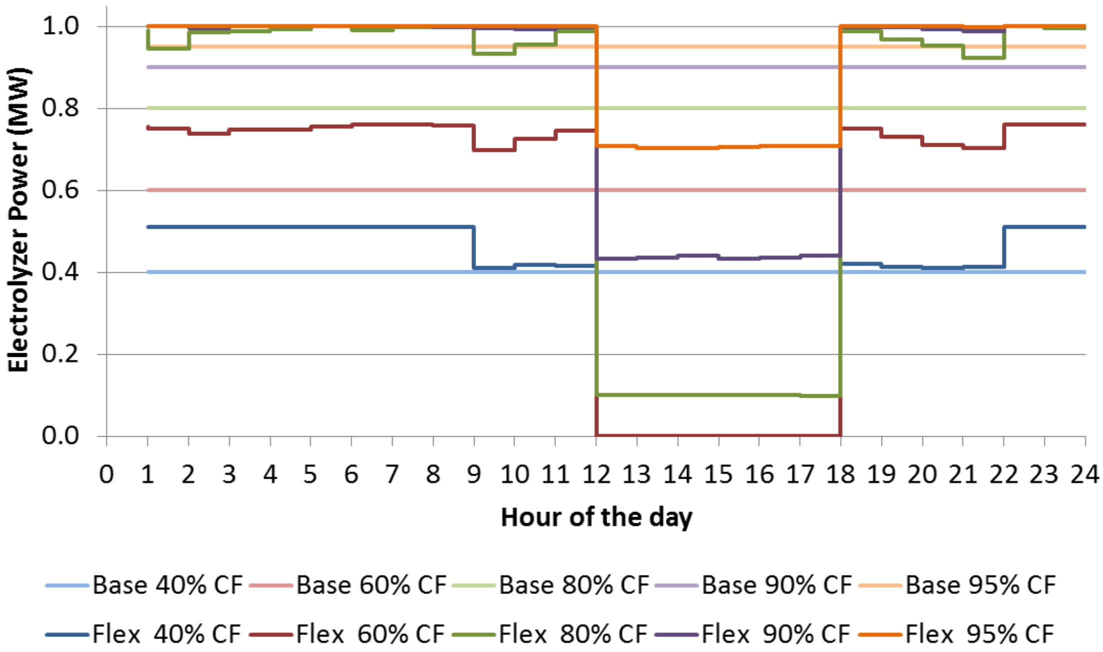

Figure 12. Average summer electrolyzer operation using PG&E E20 with no renewables

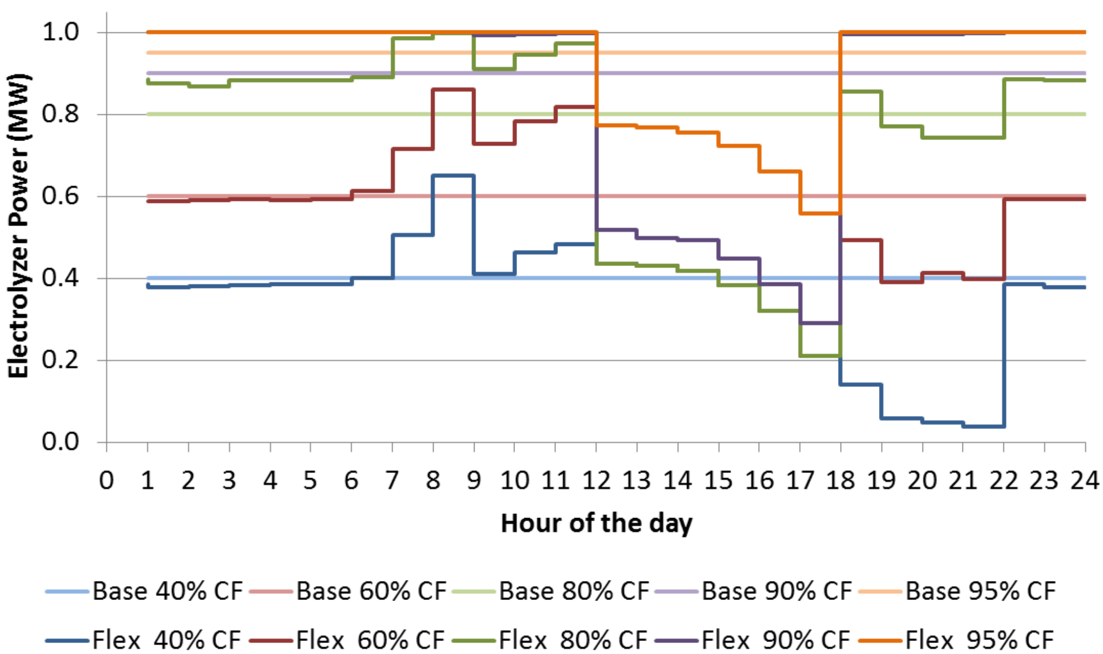

Figure 13. Average summer electrolyzer operation using PG&E E20 with 0.5MW of PV

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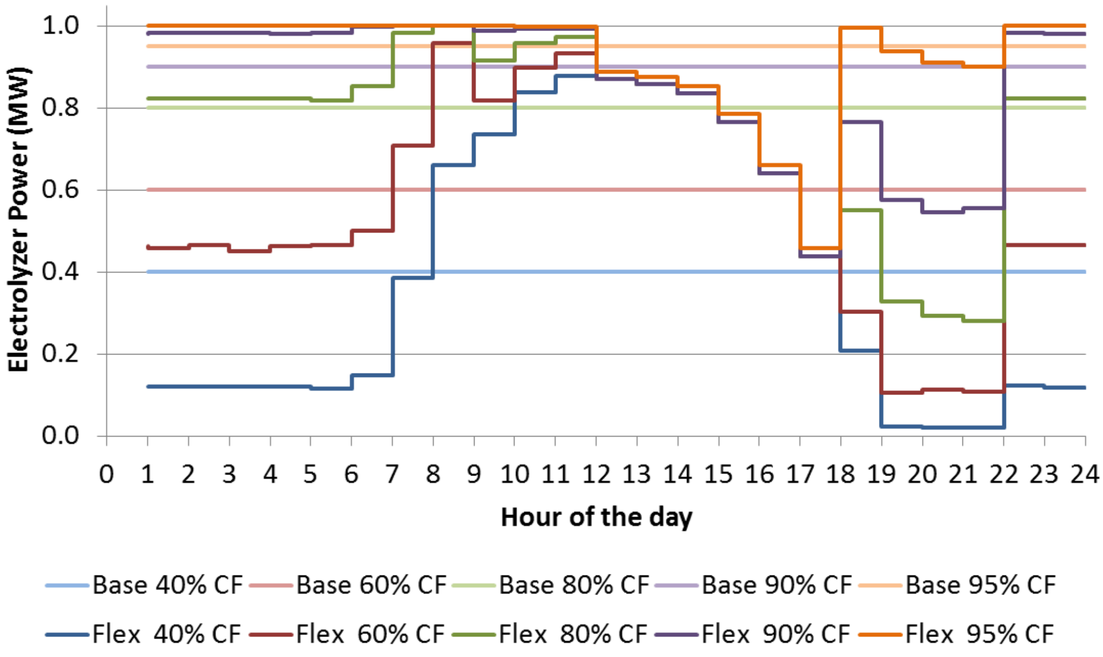

Figure 14. Average summer electrolyzer operation using PG&E E20 with 1MW of PV

Once eligible to bid into CAISO markets, the electrolyzer facility can bid into a variety of markets. As described earlier, participation in the energy markets requires a baseline to be established, and this baseline encourages participation for limited days per year and only during high-priced hours. New initiatives in California, including ESDER phase 2, seek to lower barriers for participation, which can have a profound impact on the ability for energy storage and demand response to provide grid services. For this analysis, we are focusing on ancillary service provision. Whenever the electrolyzer is producing hydrogen, its capacity less its minimum operation point (depending on the market) can be bid to provide ancillary services. The electrolyzer will receive payment for the capacity bid ($/MW) and in the event that the ancillary service is called to dispatch energy the electrolyzer will receive the locational marginal price energy payment ($/MWh). Since the number of AS events that occurs is unpredictable, we do not make an assumption about how often the electrolyzer is called to provide energy. Providing energy by reducing hydrogen production will provide additional revenue but it can also cause the device to redispatch and potentially increase the demand charge.

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6 Water Consumption

With changes to the climate, concerns for water usage and supply are of growing interest. The water consumption values by component were developed by Argonne National Laboratory (ANL) (Lambert, 2015). We take ANL estimates for water consumption for two pathways and update them to reflect California. The two pathways are hydrogen production from electrolysis and hydrogen production from steam methane reforming.

First, we must establish the definition for consumption. Consumption broadly represents the amount of water withdrawn less the amount returned. More specifically, reasons that water is not returned include evaporation, incorporation into products, or degradation to a quality level that is insufficient for future use. The components considered by ANL in their study include water consumption for electricity generation, water consumed in the reaction to create hydrogen, water treatment, production process, and cooling process.

Table 8 contains the water consumption factors by generation technology. We match the values for the selected technologies in the third column to the generation mixture for California to construct the water consumption portfolio.

Table 8. Summary of estimated electricity generation water consumption factors (based on Table 21 from ANL/ESD-15/27)

Technology	Water Consumption Factor (gal/kWh)	Selected Technologies for California Analysis
Coal boilers	**0.54**	X
Coal IGCC	**0.32**	
Residual oil boiler	**0.31**	
Residual oil ICE	**0**	X
Residual oil turbine	**0**	
Natural gas boiler	**0.39**	
Natural gas ICE	**0**	
Natural gas turbine	**0**	
NGCC turbine	**0.21**	X
NGCC turbine with CCS	**0.38**	
Nuclear power plant	**0.58**	X
Hydroelectric power plant	**9.85**	X
Municipal waste power plant	**0.61**	
Biomass boiler	**0.61**	X
Geothermal flash power plant	**1.2**	
Geothermal binary power plant	**1.7**	X
Geothermal EGS power plant	**0.95**	
Wind power plant	**0.001**	X

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Technology	Water Consumption Factor (gal/kWh)	Selected Technologies for California Analysis
Solar PV plant	**0.018**	**X**
Solar CSP plant	**0.26**	

The California Energy Commission provides information on total electricity consumption in California for each year.[20] The most current year available is 2014. The energy requirement is used along with the consumption factors to calculate the statewide total water consumption (Table 9). Worth noting is the large value for hydroelectric power generation. This value represents largely evaporation from the surface of the water. The ANL study recognizes a wide range of evaporation numbers in the literature and arrives at 9.85 gal/kWh as a generation weighted average of several types of hydroelectric generation. Additionally, "Other" and "Unspecified Sources of Power" are not associated with a specific generation technology so they are assumed to have the same consumption factor as the weighted average of the rest of the generation mixture (i.e., 1.062).

Table 9. 2014 California Total Energy Requirement

Fuel Type	2014 California Power Mixture (TWh)	Water Consumption Factor (gal/kWh)	Water Consumption (million gal)	Water Consumption (fraction of total)
Conventional				
Coal	18.9	0.54	10,200	3.2%
Large Hydro	16.4	9.85	161,048	51.1%
Natural Gas	132.1	0.21	27,738	8.8%
Nuclear	25.2	0.58	14,628	4.6%
Oil	0.046	0	-	0.0%
Other	0.016	1.062	17	0.0%
Unspecified Sources of Power	44.4	1.062	47,188	15.0%
Renewables				
Biomass	7.5	0.61	4,579	1.5%
Geothermal	13.0	1.7	22,151	7.0%
Small Hydro	2.8	9.85	27,452	8.7%
Solar	12.6	0.018	226	0.1%
Wind	23.9	0.001	24	0.0%
Total	**296.8**	**1.062**	**315,250**	**3.2%**

[20] Generation information is available here http://energyalmanac.ca.gov/electricity/total_system_power.html.

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The consumption values for stoichiometry, water treatment, production process, and cooling process come from the ANL report. There are several options for electrolysis and SMR. For electrolysis there is central and distributed. For SMR there is central, central with carbon capture and sequestration (CCS), and distributed. We select distributed electrolysis and central SMR on which to perform the analysis.

Table 10. Hydrogen production water consumption estimates (based on Table 22 from ANL/ESD-15/27)

	Distributed Electrolysis	Central SMR without CCS
Stoichiometry (gal/kg H_2)	2.36	1.2
Water Treatment Process (gal/kg H_2)	3.9	0.7
Production Process (gal/kg H_2)	2.9	1.7
Cooling Process (gal/kg H_2)	0.0	0.65

We combine the items in Table 9 and Table 10 for an electrolyzer with a production efficiency of 54.3 kWh/kg (61.4% efficient on a lower heating value basis) to construct the portfolio of water consumption. The electricity consumption for the electrolyzer does not reflect time-dependent electricity consumption but rather the average yearly electricity consumption. The portfolio is dominated by water usage for electricity as shown in Figure 15.

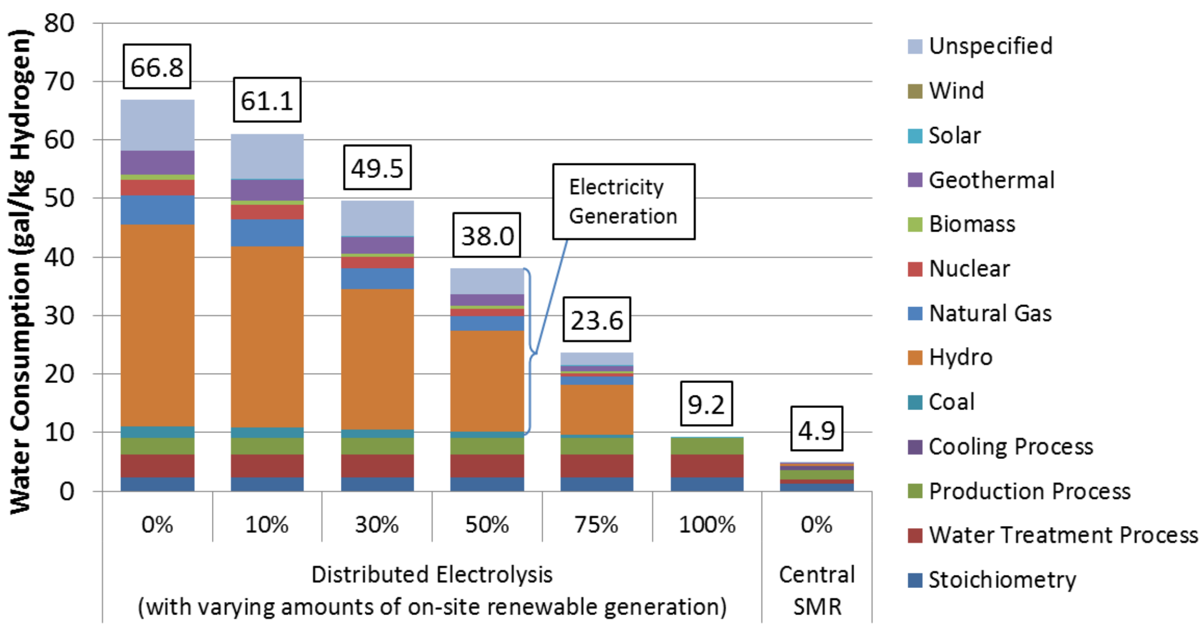

Figure 15. Water consumption for hydrogen production using electricity from 2014 California grid

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7 Credits and Incentive Programs

Alternative fuel providers in California may receive compensation from two different programs. The LCFS, implemented by the California Air Resources Board (CARB), applies to providers operating in the California market, and the Renewable Fuel Standard (RFS), which operates at the federal level. Both programs set obligations to reduce the consumption of carbon-intensive fuels. Providers of alternative fuels receive credits, which are tradeable in markets. Credits from the LCFS program can increase the revenue of hydrogen providers, including the ones that use electrolysis. Hydrogen produced by electrolysis is not currently included in the RFS program.

7.1 Low Carbon Fuel Standard

7.1.1 LCFS for Vehicles

The state of California adopted the Low Carbon Fuel Standard (LCFS) in 2009 with the goal of reducing the carbon intensity of the transportation fuel used in the state by 10% by 2020 from a 2010 baseline (CARB, 2016a). The LCFS sets annual baseline carbon intensities for gasoline and diesel. Each year, the baseline carbon intensity for each fuel decreases (Table 11).

Table 11. LCFS carbon intensity compliance levels for gasoline and diesel (2010-2020). Source: Low Carbon Fuel Standard Final Regulation Order

	Average Carbon Intensity (gCO^2e/MJ)	
Year	Gasoline	Diesel
2010	Reporting Only	Reporting Only
2011	95.61	94.47
2012	95.37	94.24
2013	97.96	97.05
2014	97.96	97.05
2015	97.96	97.05
2016	96.5	99.97
2017	95.02	98.44
2018	93.55	96.91
2019	91.08	94.36
2020 and on	88.62	91.81

Providers of fuels used for transportation in California can obtain compliance credits depending on the well-to-wheels carbon intensity of their particular pathway. Interested parties must submit their proposed pathways, including well-to-pump carbon intensity calculations, to the California Air Resources Board (CARB) for approval. The formula to calculate credits measures the well-to-pump carbon intensity (CI) of the approved pathways against the current year's baseline CI, and takes vehicular efficiency into account to complete the well-to-wheels carbon intensity calculation.

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$$Credits = \left(CI_{year\ std} - \frac{CI_{actual}}{EER}\right) \times E_i \times EER \times 10^{-6} \quad (1)$$

where:

$CI_{year\ std}$ represents the baseline CI for the displaced fuel and current year;

CI_{actual} represents the well-to-pump carbon intensity;

E_i is the energy density of the fuel or blendstock, expressed in megajoules (MJ) per unit of fuel, see Table 13;

EER is the Energy Economy Ratio, which represents the efficiency of the alternative fuel vehicle relative to a gasoline or diesel vehicle, as appropriate.

The 10^{-6} constant is used to convert grams to tons.

Approved EER values are shown in Table 12.

Table 12. EER values approved by CARB. Source: LCFS Final Regulation Order

Light/Medium-Duty Applications (Fuels used as gasoline replacement)		***Heavy-Duty/Off-Road Applications (Fuels used as diesel replacement)***	
Fuel/Vehicle Combination	***EER Values Relative to Gasoline***	***Fuel/Vehicle Combination***	***EER Values Relative to Diesel***
Gasoline (incl. E6 and E10) or E85 (and other ethanol blends)	1.0	Diesel fuel or Biomass-based diesel blends	1.0
CNG/ICEV	1.0	CNG or LNG (Spark-Ignition Engines)	0.9
		CNG or LNG (Compression-Ignition Engines)	1.0
Electricity/BEV, or PHEV	3.4	Electricity/BEV, or PHEV* Truck	2.7
		Electricity/BEV or PHEV* Bus	4.2
		Electricity/Fixed Guideway, Heavy Rail	4.6
		Electricity/Fixed Guideway, Light Rail	3.3
		Electricity/Trolley Bus, Cable Car, Street Car	3.1
		Electricity Forklifts	3.8
H2/FCV	2.5	H2/FCV	1.9
		H2 Fuel Cell Forklifts	2.1

*BEV = battery electric vehicle, PHEV= plug-in hybrid electric vehicle, FCV = fuel cell vehicle, ICEV = internal combustion engine vehicle.

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Table 13. Energy density for LCFS fuels and blendstocks. Source: LCFS Final Regulation Order

Fuel (units)	*Energy Density*
CARBOB (gal)	119.53 (MJ/gal)
CaRFG (gal)	115.83 (MJ/gal)
Diesel fuel (gal)	134.47 (MJ/gal)
Pure Methane (ft^3)	1.02 (MJ/ft^3)
Natural Gas (ft^3)	1.04 (MJ/ft^3)
LNG (gal)	78.83 (MJ/gal)
Electricity (KWh)	3.60 (MJ/KWh)
Hydrogen (kg)	120.00 (MJ/kg)

The two main pathways used to calculate the financial benefits of the LCFS program under the scenarios considered in this report comprise fuel cell vehicles and the mix of hydrogen and compressed natural gas (CNG) in CNG vehicles.

7.1.1.1 Fuel Cell Electric Vehicles

The first pathway analyzed uses electrolyzed hydrogen in a fuel cell electric vehicle. To calculate the credits per kilogram (kg) of hydrogen produced via electrolysis, the well-to-pump carbon intensity of electrolyzed hydrogen was calculated using two sources of electricity, namely, the electricity from an on-site renewable energy system and the electricity from the California grid.

In 2015, CARB approved AC Transit's request for a pathway to produce hydrogen using the energy from an on-site solar PV. The pathway's approved carbon intensity is zero (Green Car Congress, 2015). That value was used in our calculations.

The carbon intensity of California's grid electricity was used to calculate the carbon intensity of producing hydrogen using that source of energy. In Table 6 of the LCFS final order, California's grid electricity is listed as having a carbon intensity of 105 grams of CO_2-equivalent per megajoule (gCO_2eq/MJ). Considering an electrolyzer efficiency of 61.4% (Yang, 2013), the well-to-pump carbon intensity (CI) of electrolyzed hydrogen using California's grid electricity was calculated as follows:

$$Carbon\ intensity = \frac{105}{0.67} = 157\ gCO_2eq/MJ$$

The CI of the hydrogen produced using any combination of renewable electricity and California's grid electricity can be calculated using a weighted average. The resulting formula, taking into account that the percentage of California's grid electricity would be equal to 100% minus the percentage of renewable electricity, is:

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$$CI = RH2_{\%} \times 0 + (1 - RH2_{\%}) \times 157 = (1 - RH2_{\%}) \times 157 \quad (2)$$

where $RH2_{\%}$ represents the percentage of renewable energy used to produce hydrogen in an electrolyzer.

Using formulas 1 and 2, the 2016 baseline CI for gasoline of 92.5 gCO_2eq/MJ, a 120 MJ/kg energy density for hydrogen, and an EER of 2.5, the following formula was derived to calculate credits per ton of hydrogen produced for different mixes of California grid and renewable electricity:

$$Credits\ per\ ton = 20.6 \times RH2_{\%} + 7.2$$

Figure 16 shows the number of credits obtained per kilogram of hydrogen produced in an electrolyzer using different levels of renewable energy mixed with California's grid electricity.

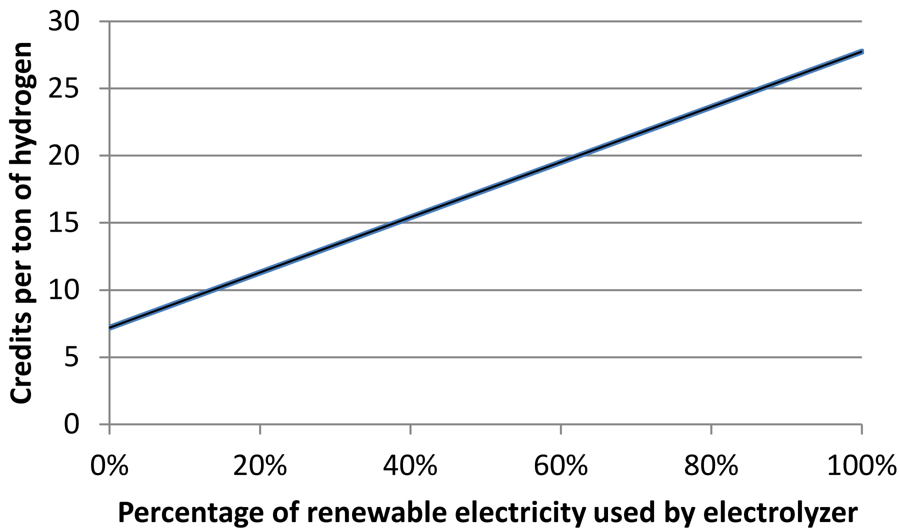

Figure 16. Credits per ton of hydrogen produced using different levels of renewable energy mixed with California's grid electricity

7.1.1.2 Hydrogen and Compressed Natural Gas Mix in CNG Vehicles

The second pathway analyzed uses a mix of hydrogen and CNG (HCNG) in heavy-duty vehicles. To calculate the credits per gallon of HCNG used to displace diesel use, the variables used were the percentage of renewable energy used to produce hydrogen in an electrolyzer and the percentage of hydrogen in the HCNG mix.

The well-to-pump CI of the mix can be calculated as the weighted average of CNG's CI (67.7 as per CARB 2009), and the CI of the hydrogen (which we derived in formula 2). Expressing the HCNG CI as a function of the percentage of hydrogen in the HCNG mix and the percentage of renewable energy used in the manufacturing of hydrogen yields:

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$$CI = H_{\%} \times (1 - RH2_{\%}) \times 17 + (1 - H_{\%}) \times 67.7 \quad (3)$$
$$= 17 \times H_{\%} \times RH2_{\%} - 66.7 \times H_{\%} + 67.7$$

Where $H_{\%}$ represents the percentage of hydrogen in the HCNG mix, and $RH2_{\%}$ represents the percentage of renewable energy used to produce hydrogen in an electrolyzer.

Using the formulas 1 and 3, the 2016 baseline CI for diesel of 91.4 gCO_2eq/MJ, the CI of California's pipeline natural gas, a CNG energy density of 0.98 MJ/scf, and an EER of 0.9, the following formula was derived to calculate the credits per ton of hydrogen produced for different percentages of hydrogen in the HCNG mix and different mixes of California grid and renewable electricity in the production of hydrogen:

$$Credits = 1.75 - 12.4 \times H_{\%} + 20.56 \times H_{\%} \times RH2_{\%}$$

Figure 17 shows the credits per ton of HCNG at different concentrations of hydrogen and at different percentages of renewable energy used in the manufacturing of hydrogen. The crossover point for all hydrogen mixture values in the figure below is at 60.3% renewable penetration.

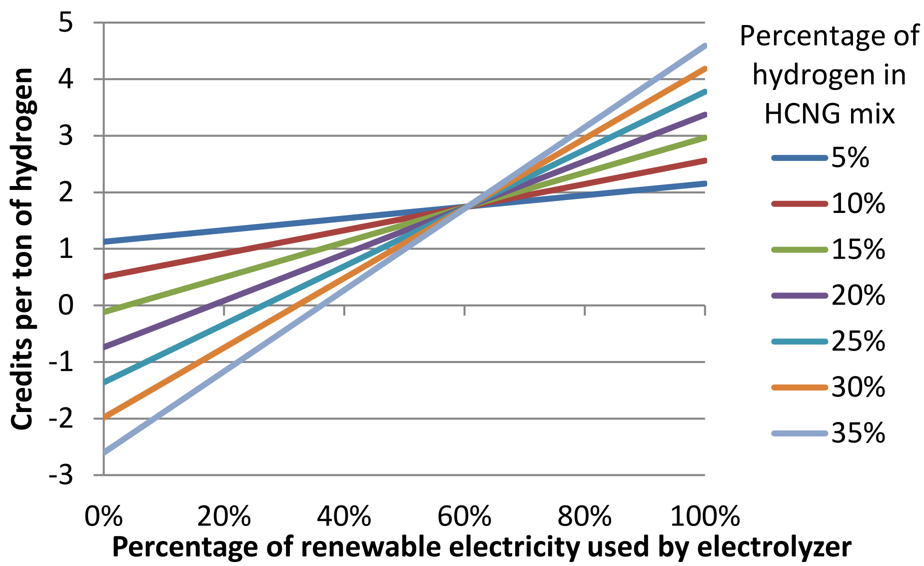

Figure 17. Credits per ton of hydrogen obtained from mixing hydrogen with CNG at different concentrations of hydrogen and at different levels of zero-carbon hydrogen

7.1.2 Renewable Hydrogen Refinery Credit Pilot Program

A refinery can receive LCFS credits by using low-carbon hydrogen to displace fossil hydrogen. The amount of credits received by kilogram of fossil hydrogen displaced depends on the carbon intensity differential between the displaced hydrogen and the cleaner hydrogen, as described in the following formula:

$$Credits = \left(CI_{Fossil}^{H2} - CI_{Renewable}^{H2}\right) \times D \times 10^{-6}$$

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Using formula 2 to substitute for $CI_{Renewable}^{H2}$ in the previous equation, we get the results shown in Figure 18. In order to start receiving credit (i.e., credit value above zero) a renewable penetration of 38% is required.

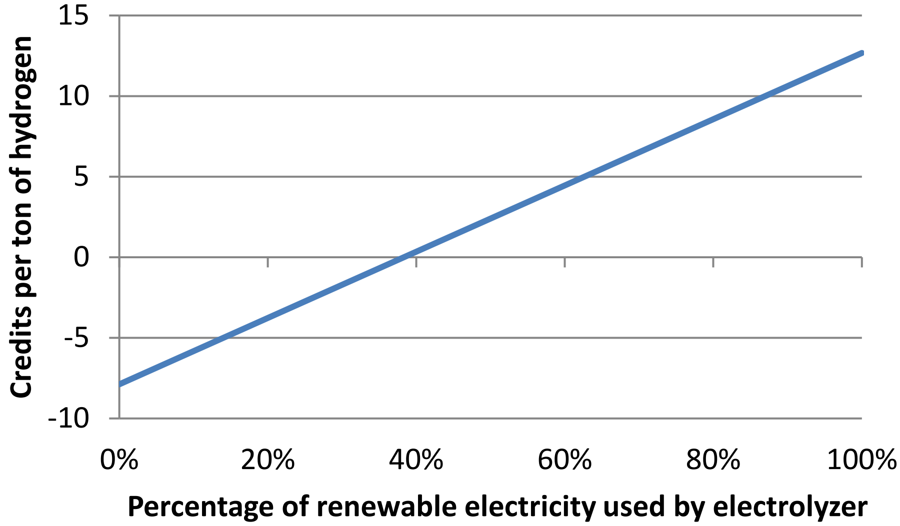

Figure 18. Credits per ton of hydrogen as a function of the percentage of renewable energy used in the production of hydrogen

7.1.3 Monetizing LCFS Credits

Fuel providers—primarily producers and importers of finished fuels—are obligated to comply with carbon intensity standards for each fuel and year. Excess credits can be traded in the LCFS market (CARB, 2011). Figure 19 shows the monthly average price per credit and trade volume since January 2014 (CARB, 2016b). The light blue band shows the range between monthly maximum and minimum prices.

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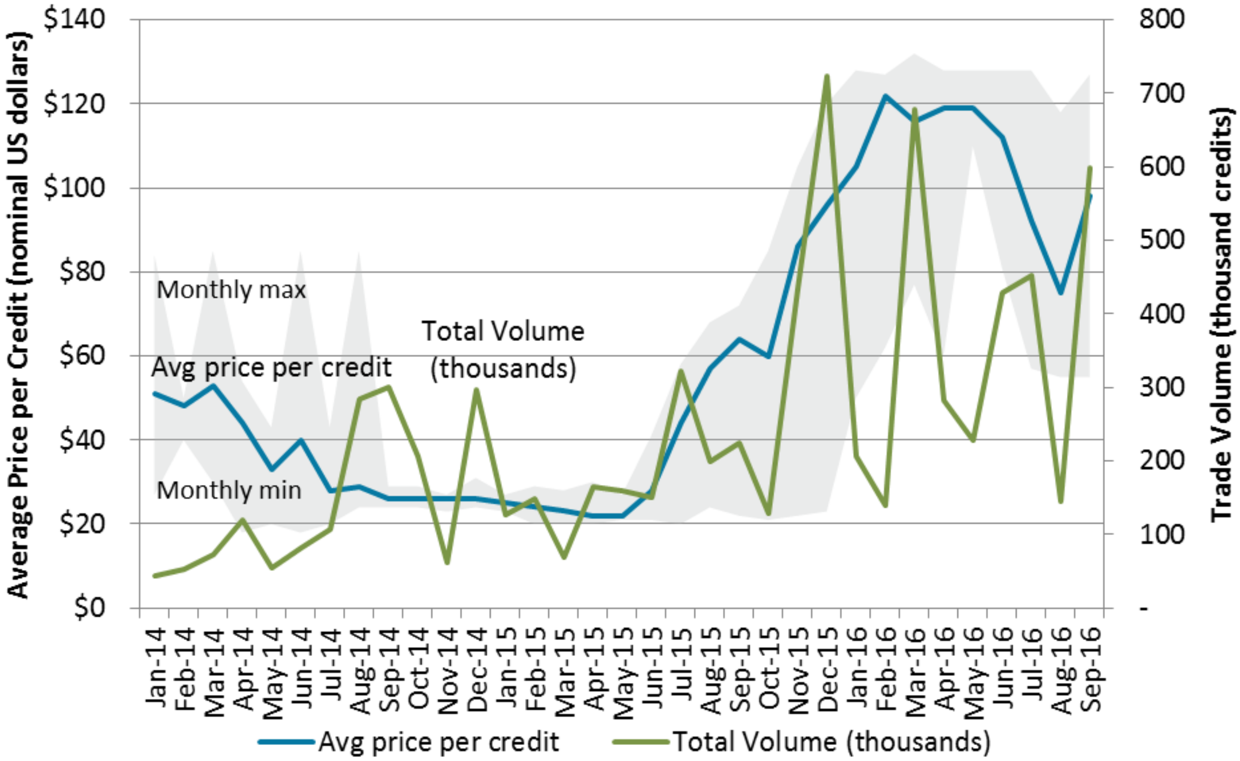

Figure 19. Monthly average prices per LCFS credit and trade volumes. Source: (CARB, 2016b)

LCFS credit prices steadily increased though most of 2015, fell during the first 6 months of 2016, and rebounded in September. Trade volumes have been volatile in the same period. The LCFS program was designed to increase compliance pressure in the latter years to allow technologies and markets to develop and mature, which could continue to put an upward pressure on trade volumes and credit prices (Ethanol Producer Magazine, 2015).

The average price during 2016 was $106. If the current trend continues, prices could reach and stay close to the program's cap of $200 for the next few years (Argus Media Group, 2015). To better understand the significance of LCFS credits in the production of hydrogen in California under the pathways analyzed in this report, the potential revenue per ton of hydrogen was calculated using a credit price of $125. Figure 20 shows credit revenues per ton of hydrogen used in fuel cell light-duty vehicles (H2/FCV), CNG vehicles using a 10% HCNG mix, and a refinery replacing fossil hydrogen. The horizontal axis represents various levels of renewable electricity used in the electrolysis of hydrogen.

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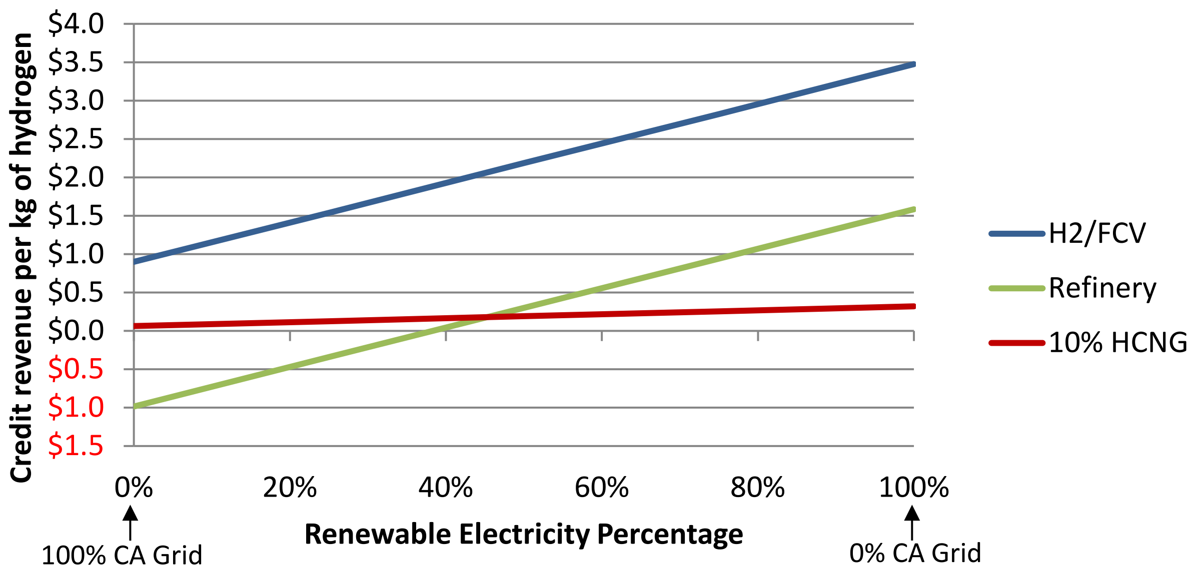

Figure 20. Credit revenue per ton of hydrogen at a price of $125 per LCFS credit.

7.2 Renewable Fuel Standard

The Renewable Fuel Standard (RFS) was established as part of the Energy Policy Act of 2005 and sets an annual minimum volume of renewable fuels to be used in the national transportation fuel supply. The RFS total fuel requirement is divided into four nested categories (each with its own volume requirement and code, shown in parenthesis): total renewable fuels (D6), advanced biofuels (D5), biomass-based diesel (D4), and cellulosic (D3 and D7) (Schnepf, 2013). Figure 21 shows a diagram of the RFS categories.

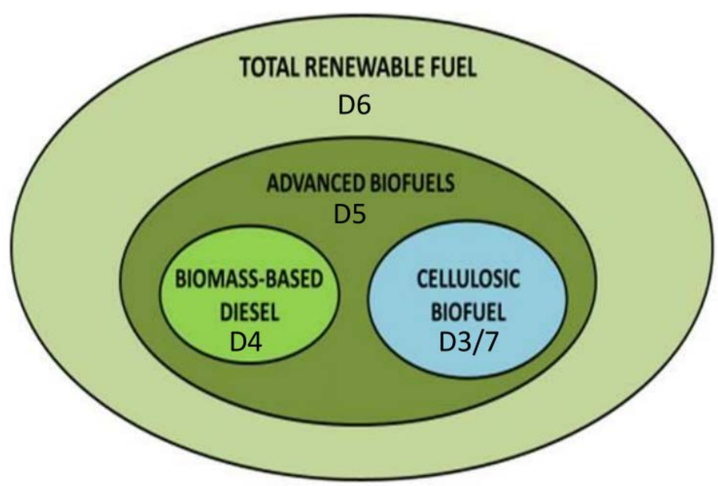

Figure 21. RFS nested categories. Source: (EcoEngineers, 2015)

Table 14 shows the characteristics and 2016 compliance levels for each category in the RFS. Renewable identification numbers (RINs) help keep track of the fuel used for compliance

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obligations. For example, each gallon of ethanol receives one RIN per gallon. Once a RIN is retired for compliance purpose, it cannot be used again.

Table 14. RFS categories, their general description, and 2016 obligations. Source:(EcoEngineers, 2015)

Category	RIN Code	Characteristics	Mandated Volume 2016 (million gallons)
Renewable Fuel	D6	> 20% GHG reduction	14,000
Advanced Biofuels	D5	> 50% GHG reduction	3,400
Biomass-derived Diesel	D4	Biodiesel, renewable diesel, etc.	1,800
Cellulosic Biofuel	D3/D7	> 60% GHG reduction	206

Currently, the RFS does not recognize hydrogen produced through electrolysis (EIN, 2014). However, the potential credit revenue from RFS can still be calculated for this type of fuel through the equivalence value. The equivalence value represents energy content of one unit of a renewable fuel compared to the energy content of one gallon of ethanol. For example, one kilogram of hydrogen contains 120 MJ, which is approximately 1.5 the energy contained in one gallon of ethanol. Therefore, each kilogram of hydrogen would receive 1.5 RINs if it was recognized as a renewable fuel under the RFS (EIN, 2014).

Since electrolyzed hydrogen is not a biomass-based or cellulosic renewable fuel, hydrogen could only be included in categories D6 or D5. Between September and October of 2015, the price of RINs was \$0.29 per D6 RIN, and \$0.39 per D5 RIN. Therefore, electrolyzed hydrogen would have received \$0.44 or \$0.57 per kg, depending on the category in which it would be placed.

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8 Hydrogen Production and Delivery Cost Comparison

It is essential to understand the business cases that are available and economically preferred for emerging technologies, including renewable hydrogen, to expand its use in a competitive environment. This section explores each of the four scenarios described in Table 6, along with an assessment of different renewable sources and additional sensitivities to quantify the potential for near-term competitiveness of electrolysis systems. The revenue and cost components for each scenario are calculated, resulting in a series of components the sum of which represents the breakeven wholesale cost of production and delivery of hydrogen. The components include revenues; utility charges; compression, storage, and delivery; and equipment costs. An example is shown in Figure 22.

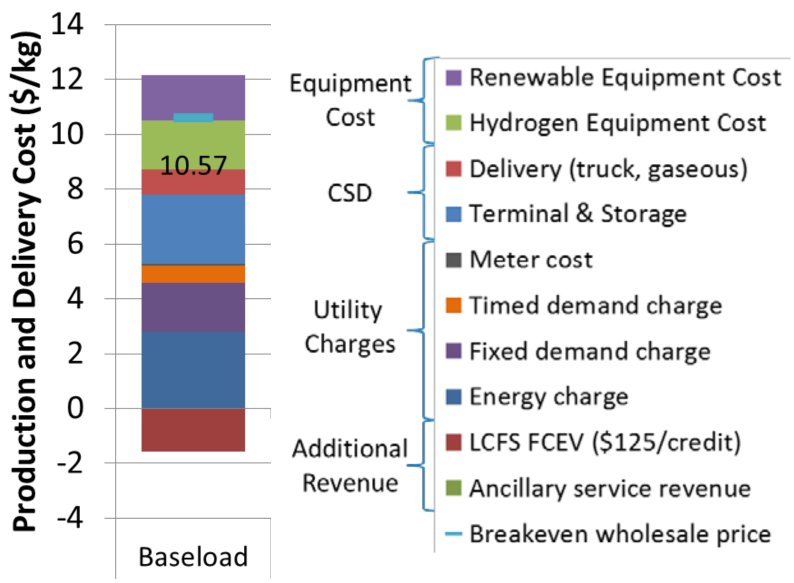

Figure 22. Example cost and benefit figure

The equipment cost shows a breakdown of the cost for installing renewables and the cost for the hydrogen production equipment, either an electrolyzer or SMR. The compression storage and delivery costs are broken into two components. The compression and storage costs are in the "Terminal & Storage" item and the delivery costs are in the "Delivery" item. The use of these costs reflects central producing plants that must deliver to the end users. To understand the costs for distribitued production sites, the delivery component can be removed but the majority of terminal and storage will remain. See Figure 5 for the values from HDSAM. Utility charges are individual items from the utlity tariff and include the meter cost, fixed and timed demand charges, and the cost for energy. The last category is for additional revenue streams, which include the LCFS credit (fuel cell vehicle fuel, refinery, or natural gas vehicles) and revenue for providing ancillary services (nonspinning, spinning or regulation). Demand response program value is considered in Section 8.6.

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8.1 Achievable Renewable Penetration

One of the valuable aspects of producing hydrogen using electorlysis is the opportunity to produce renewable hydrogen by drawing electricity from a renewable source. Those that are of most interest are intermittent and can benefit from demand-side flexibility offered by the electrolyzers. In addition, there are synergies that arise from coupling with renewable power to reduce the energy and demand charges by allowing the electrolyzer to operate during periods that would otherwise result in high energy costs or demand charges. To demonstrate a physical pathway for satisfying the LCFS, this study focuses on installing on-site renewables or collocating with existing renewable locations. To receive the demand charge reductions it is important that the electrolyzer and renewable generator are on the same utility meter. Figure 23 shows the resulting renewable penetration from installing different amounts of renewable capacity. The figure includes two facility sizes (i.e., one with only an electrolyzer and one that has a larger total load to increase the achievable renewable penetration). The other alternative to having a large facility load to help uptake on-site renewables is to participate in net metering. Unfortunately, the net metering tariffs for SCE, SDG&E, and PG&E are only appropriate for renewables less than 1 MW. The target size for our electrolyzer is 1 MW, and curtailment of on-site renewables only occurs with greater than 1 MW of installed renewable capacity.

All profiles increase linearly until they reach 100% of the electorlyzer capacity (i.e., 1 MW for this analysis). Without net metering or a large facility load the reneawble penetration falls off sharply resulting in curtailment; however if a larger facility is able to uptake the renewables then the renewable penetration can achieve 100%.

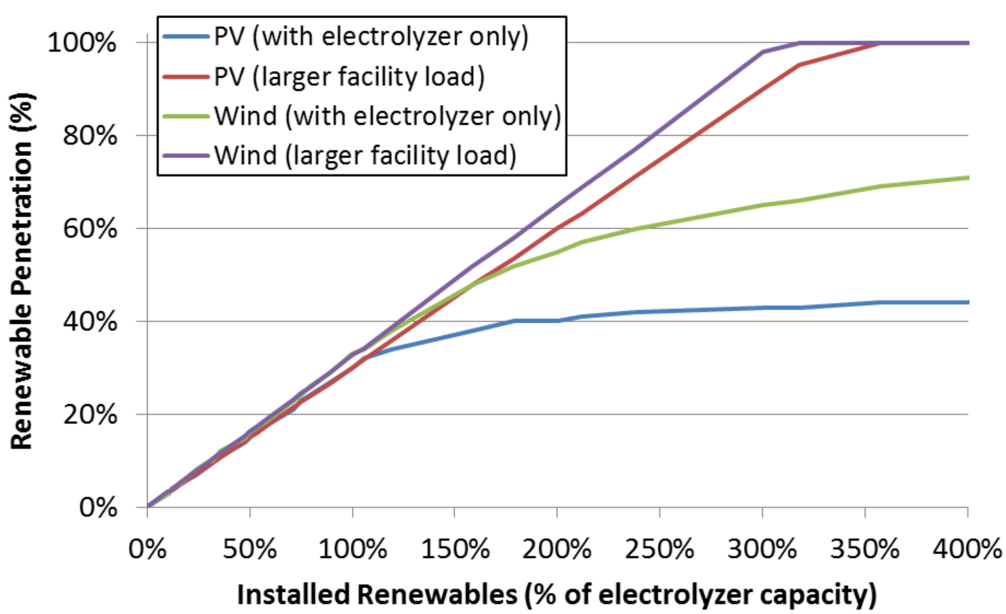

Figure 23. Resulting hydrogen renewable penetration based on installed renewable capacity

This result shows a potential challenge with installing on-site renewables. Installing wind or solar can only provide a fraction of the renewable penetraiton. When 1 MW of PV is installed for each megawatt of electrolyzer the resulting renewable hydrogen content is 32%, which means that achieving 100% renewable penetration from on-site reneawbles requires 3–3.5 times more PV or wind than electrolyzer capacity. This can result in a high cost, which must be offset by the

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additional value from the LCFS credit or for reduced electricty cost and also siting challenges for finding a sufficiently large area in which to put the renewables. More details on this tradeoff will be shown in the scenario results below.

8.2 Scenario 1: Hydrogen for FCEVs, Truck Delivery

The first scenario represents an electrolyzer producing hydrogen for use in FCEVs (to get the LCFS credit) and delivering hydrogen by truck to the location where it is needed.[21] Figure 24 shows the cost components and resulting breakeven wholesale price for production and delivery of hydrogen. For reference, it is assumed that the hydrogen delivered to FCEV stations has a current market value around \$6/kg, which means only the items with a breakeven price below \$6 are currently competitive. The baseload electrolyzers are 0.95MW and have a 95% capacity factor; all flexible electrolyzers in the figure are 1 MW and have a 90% capacity factor. To be comparable to the other devices, SMR can produce 398kg/day, as shown in Table 7. A sensitivity of capacity factors is examined in Section 8.7.2. In Figure 26, from left to right, the first two bars show the value of operating the system at baseload power mode with and without renewables. The next five bars have flexible operation and include additional revenue from provision of ancillary services. The last bar shows SMR for comparison.

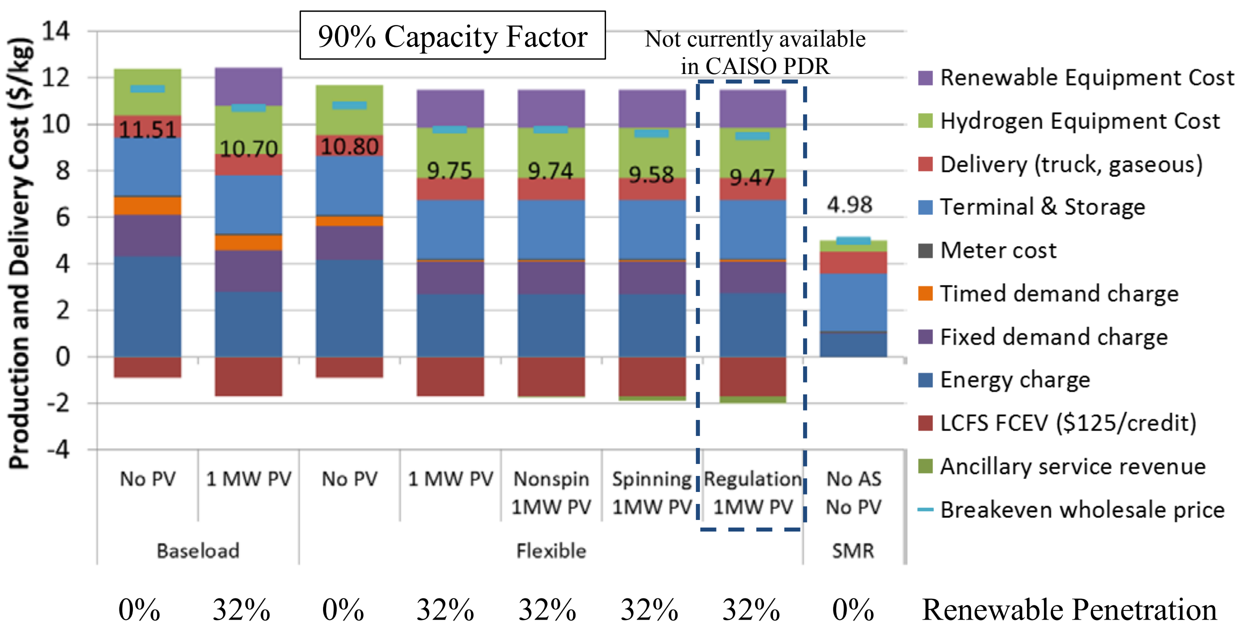

Figure 24. Cost components: hydrogen for transportation, truck delivery, 1 MW PV

Flexible operation provides significant advantages over baseload operation while still satisfying hydrogen customers. There are multiple components that contribute to reductions in the breakeven wholesale cost. Adding renewables, while maintaining baseload operation (i.e., second bar), reduces the cost by reducing the energy and demand charges while increasing the LCFS and is sufficient to offset the added cost of on-site renewables (7% reduction). Changing

[21] Compression, storage, and delivery costs vary between region (SCE, SDG&E, and PGE) and are based on the largest cities in each region (Los Angeles, San Diego, and San Francisco) but do not provide detail about location of plants and stations for other cities or production plants serving multiple cities (see Figure 7).

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to flexible operation without renewables (i.e., the third bar), results in an overall 6.2% reduction in cost, driven mostly by reducing the demand charge, which avoids high consumption during peak times. Adding renewables (i.e., fourth bar) further decreases the costs compared to the third bar. The cost reductions come from energy and demand charges along with an increase in the LCFS credit from on-site renewables.

Bidding into the reserve markets can add additional revenue and varies substantially by market (i.e., fifth through seventh bars). At 90% capacity factor, nonspinning provides $0.01/kg; spinning reserve provides $0.17/kg and providing regulation up and down yields $0.28/kg. The actual revenue for ancillary service markets is around $2,400/year for nonspinning, $24,000 for spinning, and $43,000 for regulation up and down. The values for regulation are included for comparison since presently the CAISO's PDR product does not allow for provision of regulation. It is important to note that these calculations only include reservations and do not include hours when the reserve services are called. When called, the electrolyzer will reduce its production capacity and receive the energy payment for each megawatt hour reduced; however, this can impact provision of hydrogen for customers and should be considered when specifying the system storage size. This topic will be discussed later as well.

SMR technology (i.e., the far right bar in Figure 24) has the lowest overall cost. Presently, the production and delivery cost of hydrogen to stations is assumed to be around $6/kg. SMR is the only technology that can produce at a profit in this scenario. As the need for flexibility to support the electric grid increases and the desire for renewable fuels expands, the competitiveness of electrolysis technologies is likely to improve as well.

The addition of renewables reduces the energy charges and the timed demand charge (based on the coincidence with the renewable signal) but increases the revenue from LCFS credits. All of this is at the cost of installing the renewable system. It was found to be beneficial to add renewables for all operation strategies and services provided up to around 1 MW, after which the renewable electrons are not usable unless net metering is allowed or unless the facility is larger than just the electrolyzer. This finding makes it challenging to produce 100% renewable hydrogen economically without having a new net metering tariff or as part of a larger facility. That should be considered when exploring ideal locations and configurations for placing this technology.

8.3 Scenario 2: Hydrogen for FCEVs, Hydrogen Pipeline Delivery

The second scenario represents an electrolyzer that produces hydrogen for use in FCEVs, but the delivery of hydrogen is from a hydrogen pipeline. For California, this example reflects the hydrogen pipeline in Southern California. The values for delivery from HDSAM include the purchase price of a new pipeline to provide delivery. Figure 25 shows the resulting costs and additional revenue for SMR and electrolysis with 1 MW of PV.

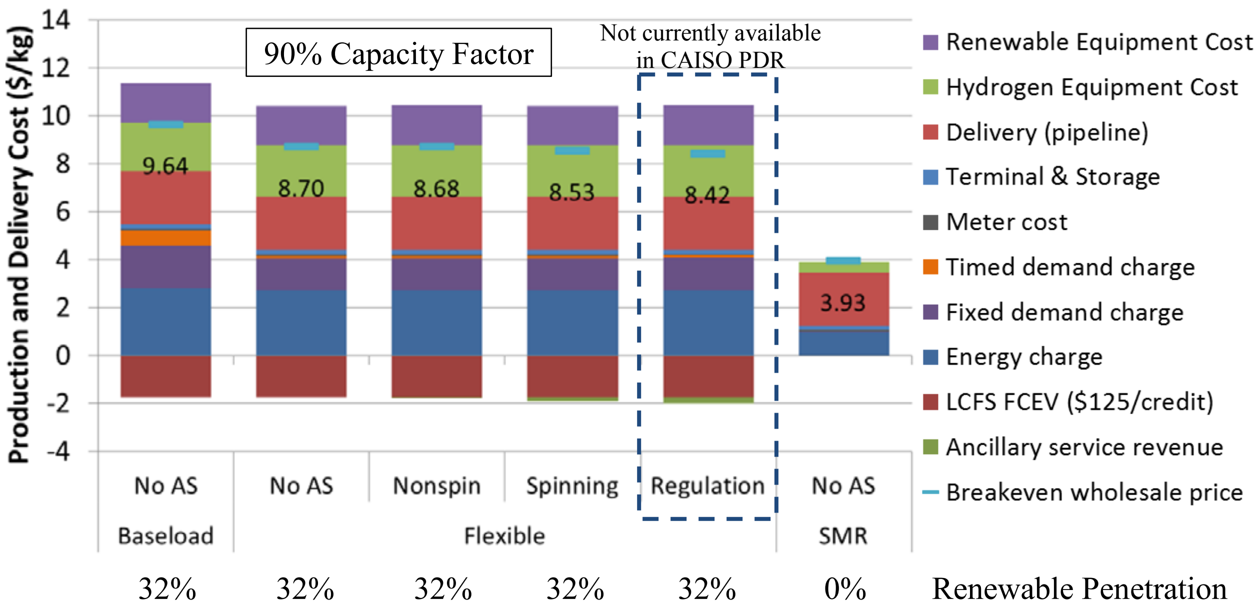

Figure 25. Wholesale breakeven price components: hydrogen for transportation, pipeline delivery, 1 MW PV

Compression, storage, and delivery via pipeline was determined to be cheaper than truck delivery, although geographic resolution is regional and based on the largest cities in California (see footnote 21) and as a result does not capture many of the intricacies of establishing a hydrogen delivery network. However, for early installations, there is an opportunity to use the existing hydrogen pipeline, which can lower the cost of delivery and also allow access to a hydrogen fueling station to receive the LCFS credit. Additionally, for demonstration projects it is possible to leverage the existing compression equipment serving the SMR plants and reduce the terminal and storage costs. The cost of CSD in the pipeline configuration is $2.4/kg. Removing delivery costs allows for hydrogen production from flexible electrolyzers at around $6.02–6.3/kg but is only appropriate for demonstrations. Like the previous scenario, the assumed wholesale price for delivered hydrogen is $6/kg, which means that SMR is economically feasible and electrolyzers that leverage existing pipeline and compression equipment (i.e., remove $2.4/kg) are right at the breakeven cost.

Flexible operation receives the same benefits as described in the previous scenario with the most significant reduction coming from demand charge mitigation. The revenues from ancillary services are similar to those from electrolyzer operation, and so the revenues for flexible operation with 1 MW of PV are the same, varying only by installed renewable capacity. At 90% capacity factor, nonspinning provides $0.01/kg; spinning reserve provides $0.17/kg and regulation up and down yields revenues of $0.28/kg. As mentioned previously, systems participating in the CAISO's markets using the proxy demand response product do not allow for provision of regulation. Regulation provision is included to show the potential value.

Of the scenarios included in this report, hydrogen for transportation with pipeline delivery is the most cost effective for electrolyzers. It also provides an opportunity to combine with existing pipeline and compression equipment to further reduce the costs.

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8.4 Scenario 3: Hydrogen for Refineries, Hydrogen Pipeline Delivery

The third scenario represents hydrogen produced for use in petroleum refining and delivered by pipeline to the point of use. Providing renewable hydrogen to refineries can enable access to LCFS credits for reducing the carbon intensity of gasoline. This configuration represents a particularly interesting case because of the large near-term hydrogen demand for refining in comparison to FCEV hydrogen demand.

Figure 26 shows the resulting breakeven price for wholesale hydrogen production. While the operation of the electrolyzers is identical to the previous two scenarios, the resulting value is lower on account of reduced revenue from the LCFS credit. As described in Section 7.1, the LCFS credit for refineries assumes that the resulting fuel in used in a gasoline vehicle as opposed to a fuel cell vehicle so the carbon intensity reduction is significantly less. Unlike the FCEV pathway for the LCFS, which provides a positive credit for all renewable penetrations, the refinery pathway must be greater than 38% renewable penetration to receive any credit. As shown in Figure 23, achieving 38% penetration requires either a net metering rate (which is not available from the IOUs for greater than a 1 MW renewable installation) or a large additional facility load that can uptake the additional renewables. For this scenario, installing 1 MW of PV or wind will reduce the energy costs but additional renewables increase the system costs and do not greatly increase the LCFS credit.

For this scenario we assume that the CSD costs are the same for providing hydrogen in a pipeline to a refinery or to a fueling station. There may be opportunities to further reduce the cost for pipeline delivery to a refinery (as compared to a fueling station) with an electrolysis plant that is on site or very close.

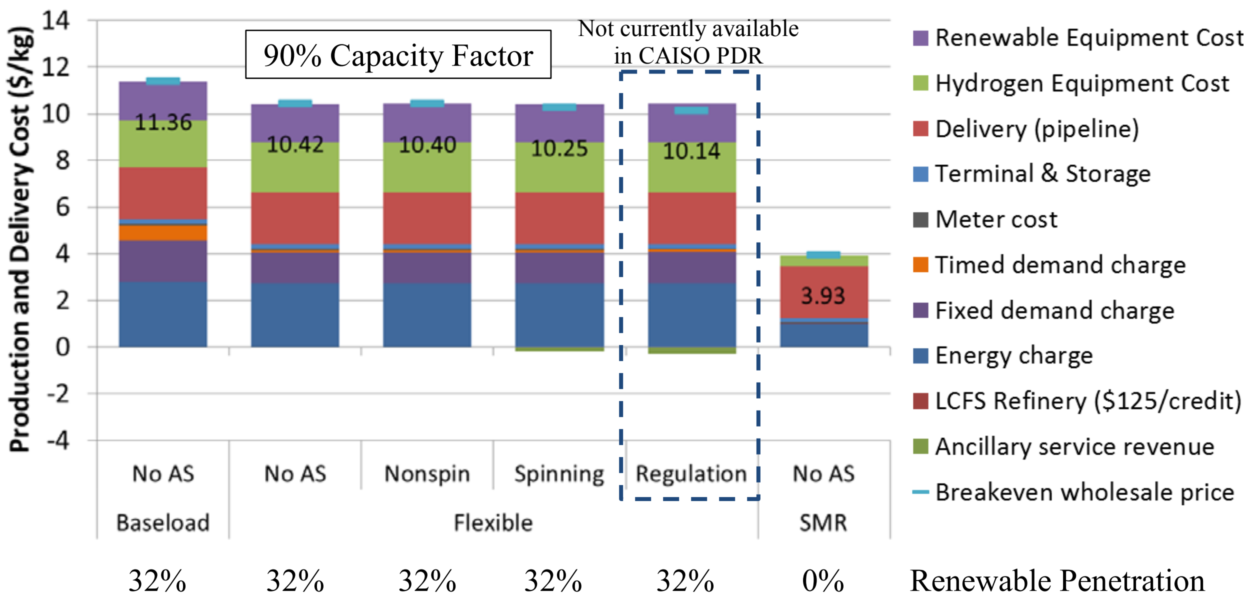

Figure 26. Cost components: hydrogen for refinery, pipeline delivery, 1 MW PV

On-site renewables reduce the production cost by reducing the energy and demand charges, increasing the LCFS value at the expense of additional renewable equipment costs. Installing more than 1 MW of renewables will allow for an even greater energy cost reduction and a greater LCFS credit; however, renewables over 1 MW of energy are not eligible for most of the

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net metering tariffs from the California IOUs. As a result, electrolyzers with more than 1 MW of renewables installed should co-locate with a larger electric load to ensure that the energy cost reductions and LCFS revenue can be realized. Figure 27 shows how additional renewables can impact the business case for refinery applications. There is a slight benefit for installing more than 1MW of renewables on account of energy reductions and receiving LCFS credit but the increase in value does not continue to 3 MW of renewables based on the $125 LCFS credit value.

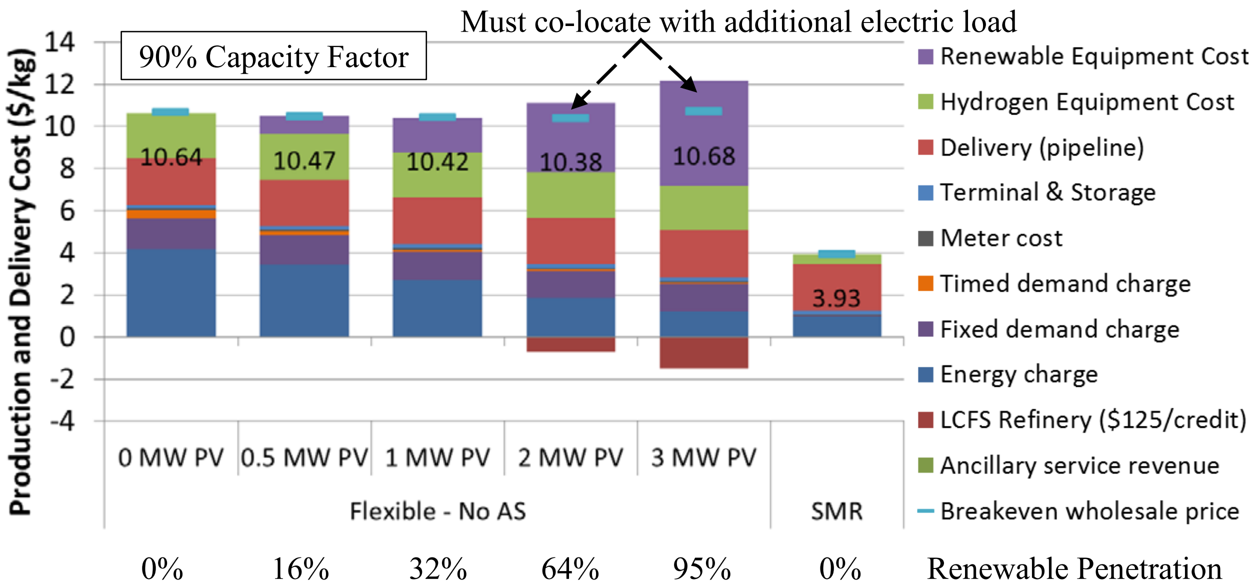

Figure 27. Wholesale breakeven price components: hydrogen for refinery, pipeline delivery (range of renewable installations)

There are several methods to access renewable electricity. The owner can purchase the panels and install them, get one of a variety of power purchase agreements (PPAs) that involve on-site renewable power generation or eligible off-site renewable generation. The benefit of on-site renewables is that, if they are behind the same utility meter, the renewables can contribute to the TOU energy and demand charge reductions shown above; however, if the renewables are not behind the same meter then they will not be able to reduce those costs.

8.5 Scenario 4: Hydrogen Pipeline Injection

The final scenario explored involves using renewables to produce hydrogen, which is directly injected into the natural gas pipeline. The renewable gas can be wheeled to a natural gas vehicle and receives LCFS credit for a renewable natural gas vehicle. For this we have assumed that the production facility has sufficient capacity to provide hydrogen at a 10% mixture for vehicles. See Section 7.1.1.2 for more details on the formulation of this pathway and the resulting LCFS value.

Figure 28 shows the breakeven wholesale price for hydrogen injection. The cost includes terminal and storage for interfacing with a pipeline but does not include additional premixing or monitoring equipment that may be required before injection into the pipeline. Additionally, SMR is not included for this scenario because, at this point, it doesn't make sense to use natural gas—a lower-value product—to produce hydrogen—a higher value product—that will be sold at the same price as the natural gas that was purchased to make it.

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The average retail price for natural gas is $5.34/MMBTU for SoCalGas GN-3 and $7.35/MMBTU for PG&E GNR2, making the average retail sale price for hydrogen injected into the gas pipeline $0.61-0.84/kg. Compared to the much higher valued transportation and industrial markets, the sale price of hydrogen injection is so low that even without the premixing, monitoring, and delivery costs necessary to inject gas, the sale price would need to be 10 times higher just to break even for this scenario.

The LCFS credit for HCNG pathway does not create a significant amount of value even with a very high renewable fraction. As shown in Section 7.1.1.2, the value for the HCNG LCFS credit can be doubled with a higher concentration of hydrogen (i.e., 50% instead of 10%); however, even doubling the credit does not significantly alter the economics for this scenario. As a result the cost/benefit for installing 1 MW of renewable generation (with a flexible operating electrolyzer) results in the same price as without the renewables.

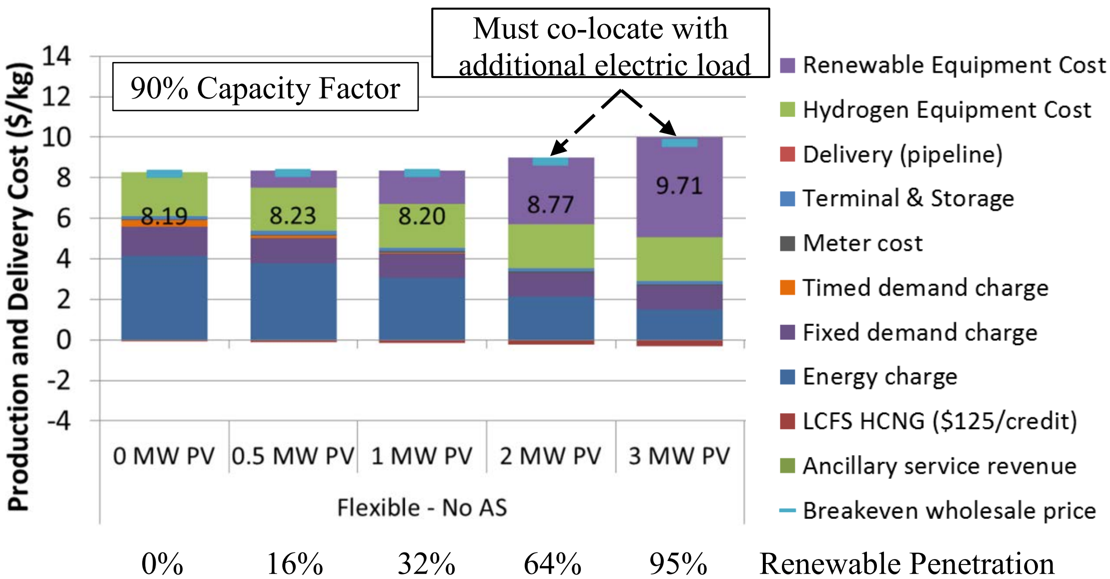

Figure 28. Cost components: hydrogen production for pipeline injection (with LCFS credit for HCNG vehicles)

8.6 Anticipated Utility Demand Response Program Value

When considering demand response revenue there are several programs with different techniques for assessing value as shown in Table 3, and different frequency, occurrence, and duration as shown in Table 4 for SCE. To calculate the potential value we can use the properties established in Section 3.1.2 along with capacity available to bid into each of the programs, which can be drawn from Section 3.2.

The available capacity changes based on operation strategy, installed renewables, and capacity factor. Based on the demand response event history data in Table 4, which was applied to electrolyzer operation for the PG&E E20 utility rate, the following table explores the maximum capacity available to participate in each program (Table 15). Depending on the available on-site storage and the hydrogen demand, this value can be reduced and should be considered when selecting the level of demand response participation.

Table 15. Available capacity for bidding into utility DR programs

Installed Renewables	Program	Operation Strategy	Annual Capacity Factor 40%	60%	80%	90%	95%
			Available Capacity for DR (MW)				
No PV	All	Baseload	400	600	800	900	950
	BIP[a]	Flexible	0	0	99	432	704
	CPP[b]	Flexible	0	0	99	432	704
	CBP[c]	Flexible	0	0	99	432	704
	DBP[d]	Flexible	0	0	99	432	704
0.5MW PV	BIP	Flexible	383	383	383	448	722
	CPP	Flexible	319	319	319	386	661
	CBP	Flexible	211	211	211	290	559
	DBP	Flexible	141	211	211	290	559
1MW PV	BIP	Flexible	766	766	766	766	785
	CPP	Flexible	641	641	641	641	660
	CBP	Flexible	438	438	438	438	457
	DBP	Flexible	207	303	438	438	457

[a] BIP = base interruptible program
[b] CPP = critical peak pricing
[c] CBPP = capacity bidding program
[d] DBP = demand bidding program

Using the value for demand response programs shown in Table 3 and the available capacity shown in Table 14, the resulting value for each program is calculated and shown in Figure 29. Baseload operation ensures that the capacity is available when events are called; however, a larger amount of revenue is lost because of higher energy and demand charges. The highest values occur with 1 MW of PV, which allows for the greatest afternoon capacity for program participation with flexible operation. For the values listed by PG&E, the BIP program is the most valuable followed by the CBP, DBP, and lastly the CPP program. The value for these programs varies between utilities and can change from year to year.

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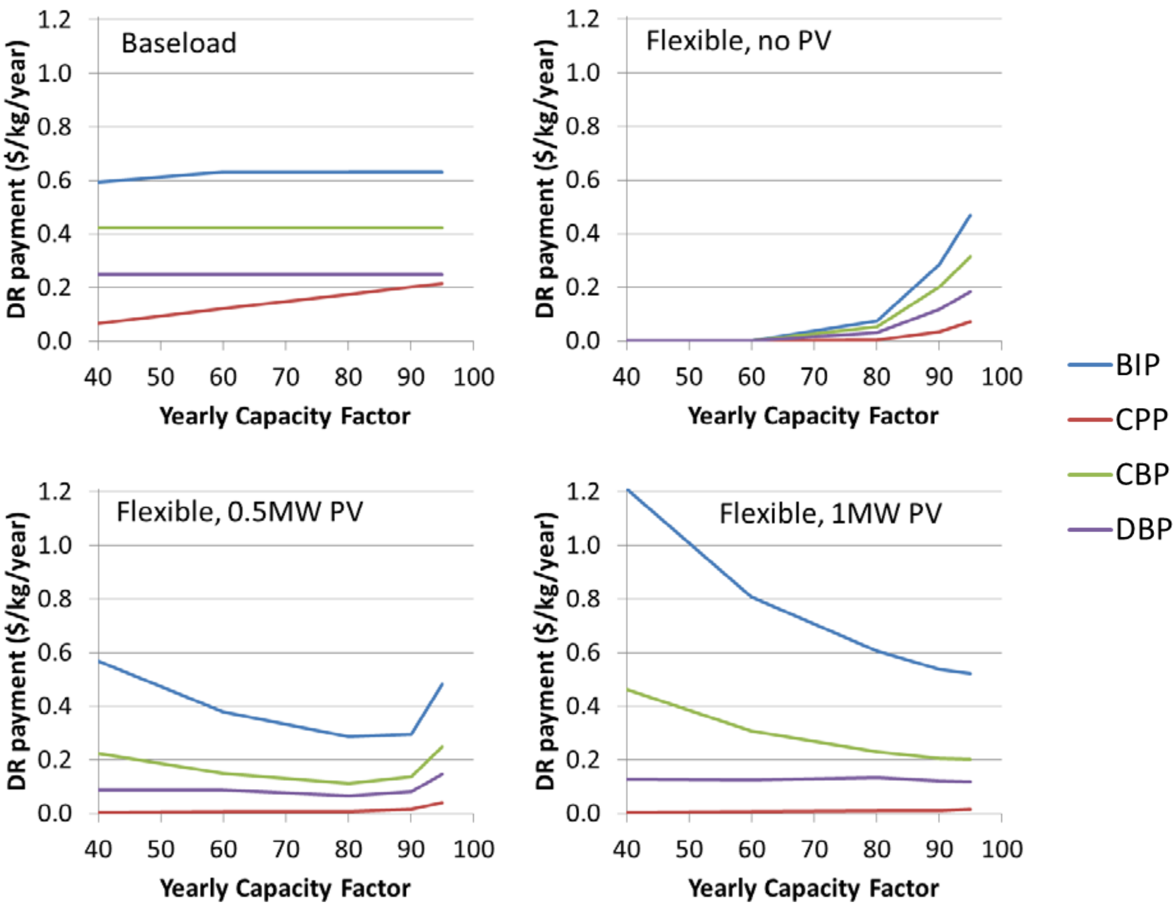

Figure 29. Demand response program value with PG&E E20 rates for varying capacity factor and installed renewable capacity

8.7 Additional Sensitivities

8.7.1 Hydrogen Production at Renewable Sites

This section evaluates two other prominent configurations in which renewables can be combined with electrolysis equipment, namely electrolysis using curtailed renewables, and islanded production of hydrogen.

With growing concern for excess renewable generation in California there may be an opportunity to utilize otherwise curtailed energy if the electrolyzer is located near the renewable site that must be curtailed. Previous modeling work done by NREL with California's Long Term Procurement Planning model predicted that in 2024 there could be 102 hours of renewable curtailment for 33% total renewable penetration and 845 hours for 40% penetration (Eichman, 2015). The production cost model used for that study performs an hour-by-hour analysis for the entire Western Interconnection that includes reserve provision and local, state, and regional constraints, and models every generator. The model geographic resolution is at the utility level in California and at the balancing area outside of California. The model includes a high level of operational detail and results in 1%-10% of hours curtailed. With finer geographic resolution, it is possible that the number of hours of curtailment could increase; however, this will not always occur at the location where the generator is installed. Because electricity demand and renewable

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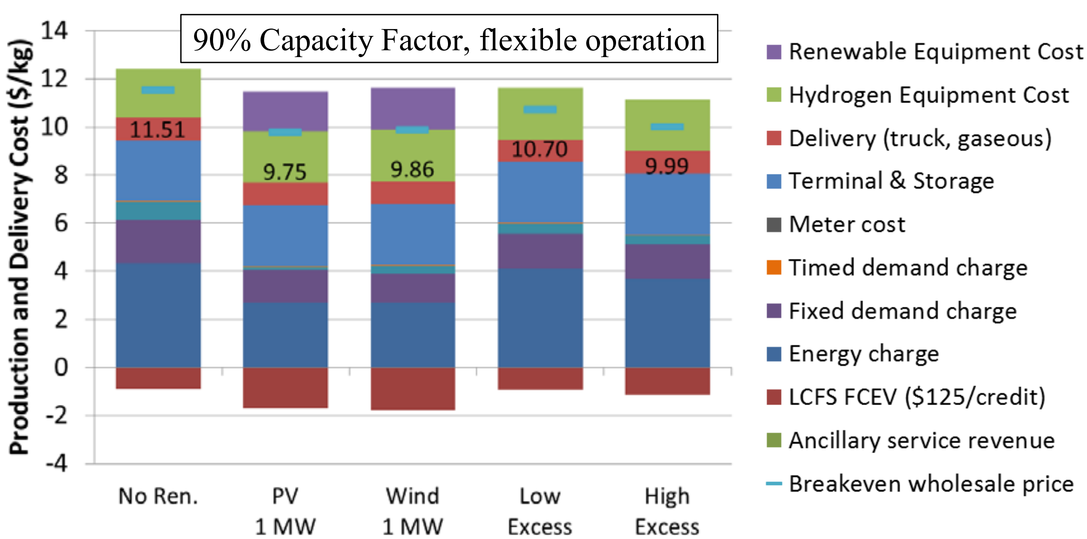
generation fluctuate seasonally, the model predicts that curtailment hours are concentrated in spring and summer, while fall and winter are less likely to experience excess generation. We perform a sensitivity analysis on the value of excess generation by assuming that utility-scale renewable sites could have between 102 and 845 hours of excess generation, and by collocating the electrolyzer with this facility it would have access to free electricity during those hours.

The second configuration considers a renewable installation that is islanded from the grid. The resulting hydrogen is 100% renewable, and since you are not interacting with the utility the cost of energy is exactly the cost of the renewable installation—with no additional electric utility rates.

Figure 30 shows the production and delivery cost for hydrogen with and without excess renewable generation. For comparison, the first two items are the same as in Figure 24 (hydrogen for transportation with truck delivery). The third item looks at the value of using wind, which has a slightly higher capacity factor than PV and a lower cost based on the assumptions in Table 5; however, the time that the wind is available does not help to reduce the demand charge as much as PV. The fourth and fifth bars consider low and high levels of excess generation.

Using otherwise curtailed energy can reduce the cost and increase the LCFS credit value; however, the reduction is limited due to the limited hours of excess generation. Installing on-site renewables or collocating with a larger renewable farm can provide greater value than relying on limited excess hours of generation alone. The best solution is a combination of both: install or collocate near renewables and use renewable generation more often than just during hours with excess.



0%	32%	34%	1.2%	9.6%	Renewable Penetration
0	0	0	102	845	Hours of free electricity

Figure 30. Cost impact for different renewable configurations: excess generation

The other configuration explored in this section is dedicated renewable production that is not grid connected (Figure 31). The first three bars are the same as in Figure 30 and represent

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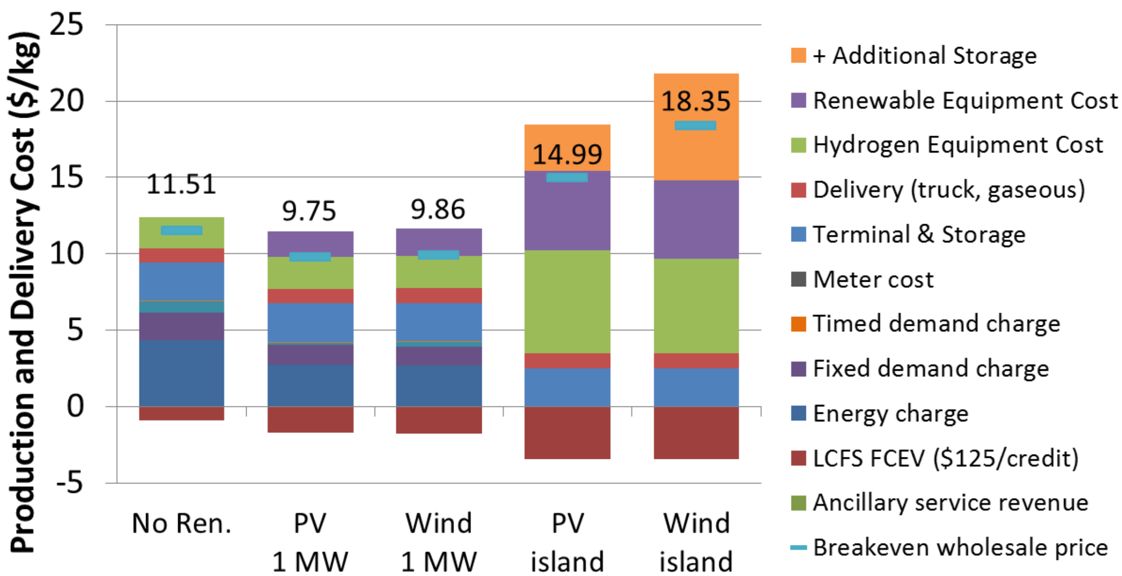
flexible operation of an electrolyzer to provide transportation fuel with and without renewables. The last two bars are for islanded configurations and vary by type of renewable.

The islanded configuration is substantially more expensive than when grid connected. One of the challenges with islanded operation is that renewable generation is seasonal, particularly for wind, which limits the amount of hydrogen that can be reliably provided to a customer. For this analysis we assume that the sale of hydrogen is constant for each hour and that on-site storage provides a buffer between time of production and use. For the grid-connected configurations, we assume 74 kg of storage. For the islanded configurations the storage level is much more important. The fourth and fifth bars require additional storage to smooth the hydrogen production from seasonal electricity production variations, as shown in the accompanying table in Figure 31. The need for additional storage is highly dependent on the renewable signal. Because we used the historical aggregated utility-scale renewable signal for California the generation at a single site is likely to be even more variable than shown here, resulting in the need for even larger storage than predicted to maintain hydrogen supply.

Additional hydrogen storage tanks add significant cost to the system. We consider this cost and add another item titled "+ Additional Storage." Storage is assumed to cost \$1,000/kg annualized over the system lifetime (20 years) with an interest rate of 7%.

More storage capacity for islanded sites increases the production output, which then decreases the cost per kilogram of hydrogen for each component. Even though an islanded system does not have any utility rates and has 100% renewable hydrogen, the electrolyzer is underutilized, which negatively affects the cost of production.



	32%	34%	100%	100%	Renewable Penetration
74	74	74	1,602	3,831	Storage capacity (kg H_2)
398	398	398	126	137	H_2 Production (kg/day)
90%	90%	90%	27%	30%	Capacity Factor

Figure 31. Cost impact for different renewable configurations: islanded renewables

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8.7.2 Impact of Varying Capacity Factor Operation

Operating electrolyzers in baseload mode means that the resulting electricity price is the average of all the time periods (e.g., off-peak, on-peak); however, flexible operation enables the operator to reduce electricity costs by avoiding high-price time periods for TOU or real-time pricing. The amount of the flexibility is determined by the required hydrogen output compared to the maximum power of the equipment. This is characterized by varying the yearly capacity factor of the electrolyzer. A high yearly capacity factor represents nearly constant use, while a low capacity factor means that the unit is oversized for the application. The value of oversizing the equipment comes from the ability to more effectively avoid high energy prices and high demand charges, and capture additional savings from other markets.

Oversizing with flexible operation is a balance between lowering the energy cost at the expense of the equipment capital cost. Figure 32 shows the resulting production and delivery cost for different capacity factors operation. Notice that the minimum cost occurs around 90% capacity factor (CF). While this produces more hydrogen than a lower CF, the energy costs are higher, particularly the timed demand charge, on account of the high peak demand charge, resulting in higher overall production costs. On the other side, as the CF is reduced, the cost of energy falls but so does the hydrogen sold. Hydrogen payments are the primary form of revenue used to pay for capital and energy costs, so the overall cost per unit of production rises.

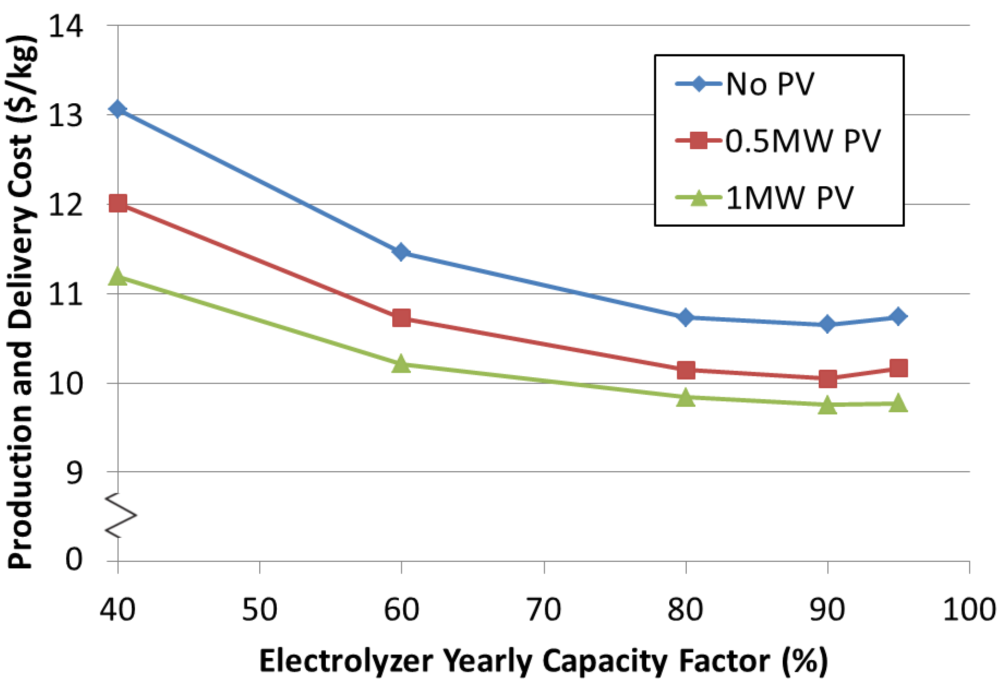

Figure 32. Wholesale breakeven price for varying yearly capacity factors: flexible hydrogen production for transportation with truck delivery

For this study we found that all of the examined rates demonstrate the same behavior; however, it is easy to envision another rate structure in which the optimal capacity factor could be different. For example, if the peak energy and demand charges are increased significantly, it will drive the optimal production cost to a lower capacity factor in an attempt to avoid those charges.

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8.7.3 Utility and Voltage Connection Comparison

The rates and delivery costs vary by the location considered and the electrical connection voltage. Up until this point we have included the average of all three IOUs and have selected secondary voltage connection, which is typically below 2 kV (see Table 1). By increasing the voltage of interconnection, the customer takes on more of the responsibility for installing equipment to accept the voltage. Typically, this situation results in a fall in energy cost, a fall in the demand charges, and an increase in the cost for electrical interconnection and metering. Figure 33 shows how the costs vary by IOU and connection.

In each case, SCE has the lowest-cost electricity, PG&E has the second lowest, and SDG&E has the highest-cost electricity. Higher voltage connection results in lower energy costs; however, we have not included the additional cost of the electrical equipment required to achieve higher voltage connection. With only a ~$1/kg reduction in cost it is unclear whether the electrical equipment cost will outweigh the benefit gained.

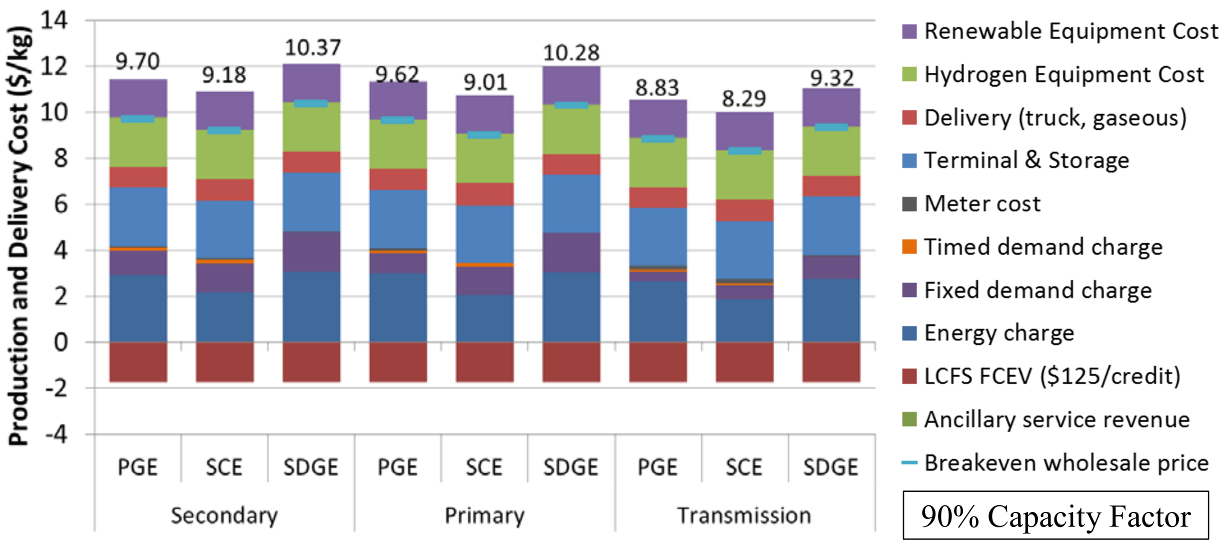

Figure 33. Cost components by connection: hydrogen for transportation, truck delivery, 1 MW PV

A similar comparison is provided for each of the rate schedules considered in this study. Figure 34 shows the rates separated by utility and operating strategy. As expected, all of the flexible electrolyzers have a lower total cost than the baseload systems. Notice how the demand charges are replaced with higher energy costs in the renewable rates.

With baseload operation, the renewable rates—excluding DGR—provide a reduction in the cost. However, with flexible operation, the non-renewable rates also provide a lower cost. The reduction in timed and fixed demand charges provided under the renewable rates is important with relatively flat operation profiles, but if the system can already reduce its demand charge with flexible operation then it is better if the system receives a lower energy cost. This trend is similar for all of the installed renewable capacities as well as for PV or wind.

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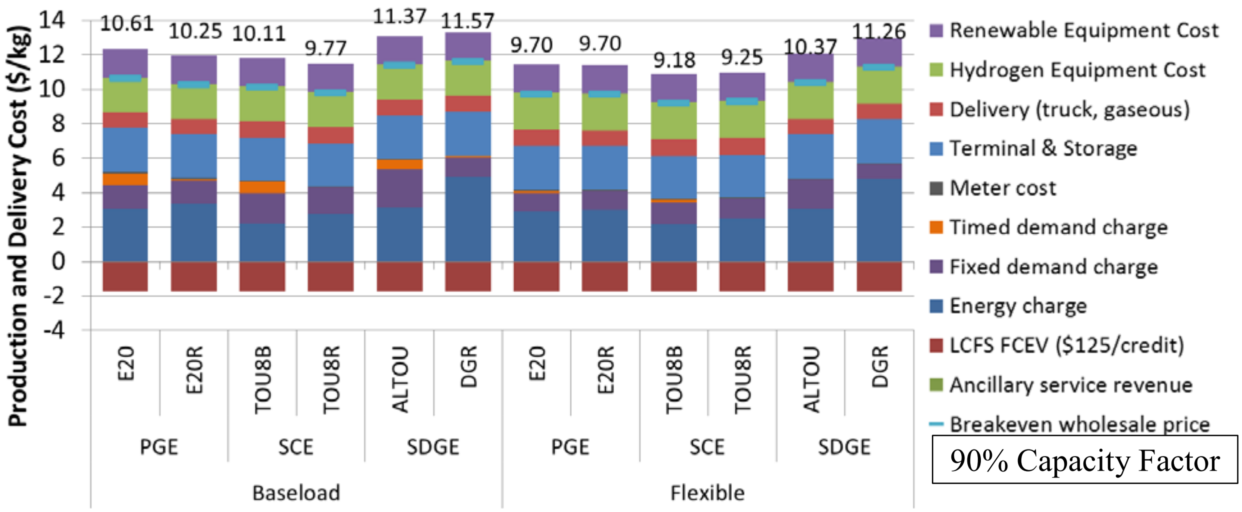

Figure 34. Cost components: hydrogen for transportation, truck delivery, 1MW PV

8.7.4 Impact of Storage Capacity

Flexible operation of electrolyzers requires that some storage is available to buffer the production with the demand of hydrogen. Sizing the storage tank is a balance between ensuring reliable supply at the lowest cost and additional system costs for more storage tanks and balance of plant equipment. For this study we assume that the supply for hydrogen is constant each hour for the entire year. The authors recognize that there is weekly and seasonal variability in fuel demand, which can have an impact on the optimal sizing. This variability has been explored briefly in previous work (Eichman, 2016), and should be considered for future work.

From an equipment operation perspective, increasing from 0 kg to 3,094 kg of storage (i.e., 0 to 168 hours at rated electrolyzer capacity) has a modest impact on the operation of an electrolyzer and has a much more profound impact on the cost. Since baseload operation produces the exact amount required each hour, no change will occur for oversizing the storage under baseload operation. For flexible operation, greater storage capacity provides value by increasing the level of variable operation, which further reduces the energy costs. At some point there will be no added value for additional storage and the cost of storage will begin to dominate. Figure 35 shows the impact of various amounts of storage capacity on the production cost, including variable storage costs.[22] Reducing the storage below a few hours dramatically reduces the ability to shift hydrogen production and force the flexible operation value to approach the baseload operation value (i.e., 0 hours of storage).

Since a larger storage system will increase the overall cost, the optimal choice is a balance between added value and storage costs. From Figure 35 it becomes apparent that the added benefit from additional storage dramatically falls after 8 hours, after which the additional storage costs begin to dominate. Based on the assumed additional storage costs (see footnote 22), the

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[22] We assume a storage cost of $1,000/kg. Identical to the other capital calculations, the net present cost is annualized over a 20 lifetime at 7% interest rate.

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minimum cost occurs around 3-4 hours. The same trend occurs for systems with less PV (500 kW) and without any renewables. Four hours was selected as the storage requirement for the majority of the results in this report to minimize the energy costs while also managing the storage costs.

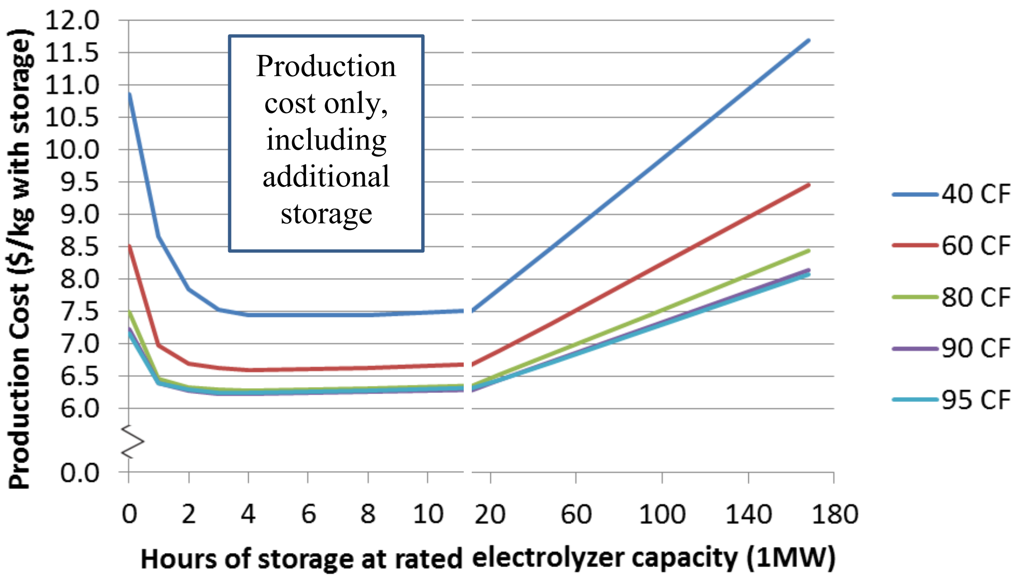

Figure 35. Impact of storage capacity on production cost that includes 1 MW PV (with storage)

While a few hours were determined to be optimal, there are opportunities to benefit from a greater amount of storage. Those opportunities include (1) facilities with other electricity loads, depending on the amount and shape of additional load, (2) new utility tariffs, or (3) new ISO markets that value long duration storage. Any of these changes can impact the economics for greater amounts of on-site storage.

8.7.5 Average Retail Electricity Prices

By introducing flexible operation and renewable generation to the system, the cost to produce hydrogen is reduced. The reduction comes largely from reductions in the average energy costs and from fixed and timed demand charges. The resulting combined average electricity prices for all three IOUs are shown in Figure 36. These include only the retail utility rate items (energy, demand charge, and meter) and the cost for a renewable generator, if applicable.[23] Baseload operation receives between $111 and $141/MWh including all electricity cost components. The most significant change is the reduction in cost from operating the electrolyzer flexibly. The addition of renewables and ancillary services provide an additional reduction. SDG&E has the highest combined average energy rates, followed by PG&E and the lowest rates are for SCE.

[23] This calculation does not include any impacts from the LCFS, electrolyzer cost, or CSD costs. This is an important distinction since the SCE electricity costs increase with 1 MW of renewables while the overall system cost decreases on account of the LCFS credit.

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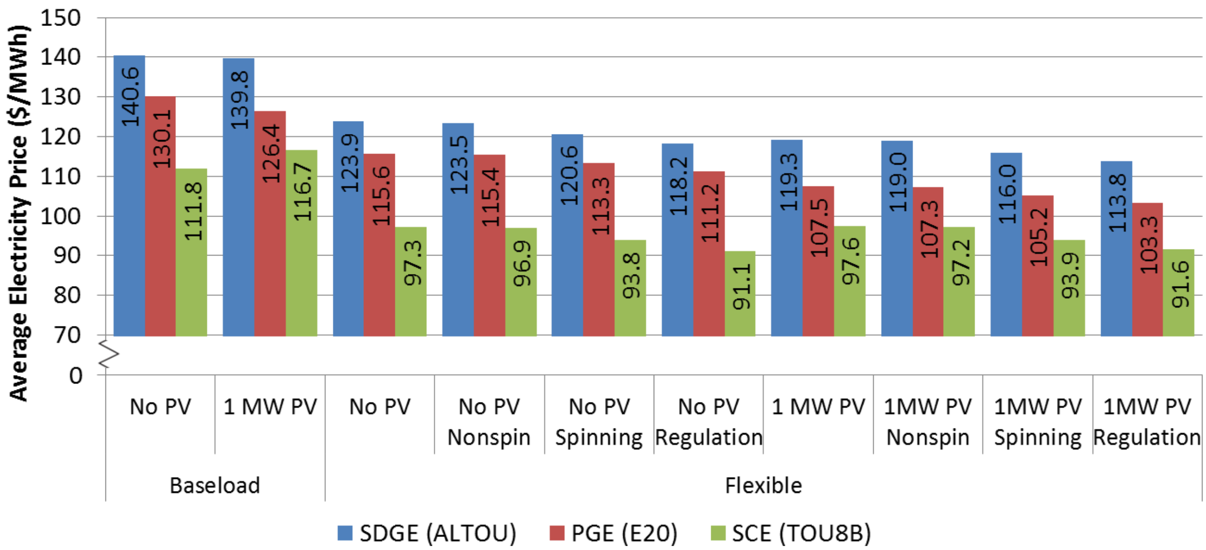

Figure 36. Average electricity price with and without renewables and ancillary services

Another alternative to purchasing and installing renewables is to enter a PPA with a renewable provider. The PPA can entail a third party installing renewables on-site and providing the purchaser with the power, or it can require that the third party install the renewables off-site and wheel the power to the electrolyzer. For comparison to PPA values, the breakeven cost of electricity from purchasing the renewable generator and installing on-site for this study is $32/MWh (3.2¢/kWh) for PV and wind, based on the cost assumptions in Table 5. While the PPA can result in similar energy prices with or without requiring an on-site footprint, wheeling renewable electricity will not help a facility reduce its peak energy and demand charges, which is an important part of the cost reductions from flexible operation.[24]

8.7.6 Ancillary Service Revenue

The ancillary service revenue provides an incremental incentive to the electrolyzer owner to help support grid needs. Participation in ancillary service markets through the CAISO's PDR requires that communication requirements be met. In addition to the revenue-grade meter for the utility, a revenue-grade meter for CAISO transactions is required (which itself requires telemetry for ancillary service markets). For comparison, the revenue-grade meter in the utility rates is between $5,600 and $12,000 per year, not including telemetry.

Revenues increase with the service provided. Regulation up and down, although not eligible in the PDR, would provide the most value, followed by spinning and then nonspinning reserves. Also, revenues increase with increasing capacity factor. This is because ancillary services are provided by shedding load so that the more a system operates the more capacity is available for providing ancillary services. The absolute revenue is lower for lower capacity factors; however, the $/kg is higher because less hydrogen is produced. That means that lower capacity factor devices are better able to take advantage of ancillary services for the lower amount of hydrogen that they produce.

[24] The demand charge reduction is shown in Figure 26 to be on the order of $0.70/kg.

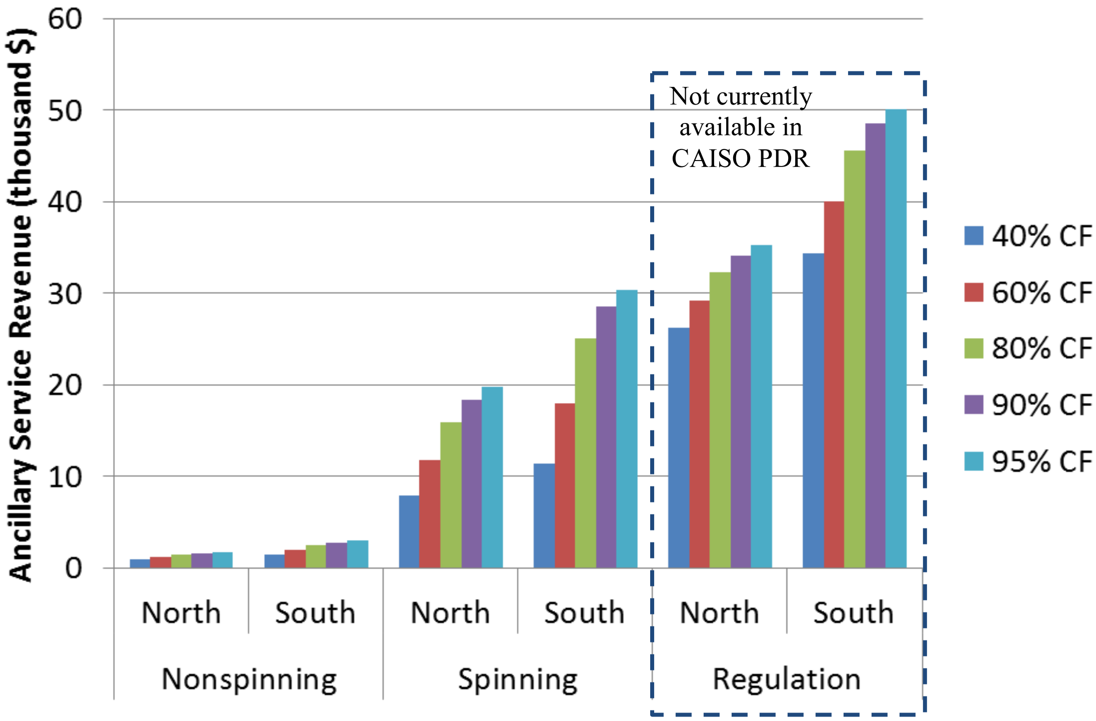

Figure 37. Revenue from ancillary services by region and service based on 2015 prices

8.7.7 Carbon Mitigation Cost

Each of the scenarios explored has a unique impact on the carbon emissions. The carbon mitigation cost is constructed by comparing the capital cost to the carbon reduction. The cost components include all capital and fixed operation and maintenance costs for the electrolyzer and the renewable generator. In this way, the mitigation cost represents the carbon reduction benefit from an incentive that goes directly toward the capital cost as opposed to one that focuses on the variable costs (e.g., fuel, electricity).

There are other ways to purchase renewable electricity that do not involve direct purchase of the generation asset. We have discussed other options earlier in this section; however, for this calculation, it is assumed that the entire cost of the renewable generator is included.

The initial mitigation cost point without renewables is set by the electrolyzer equipment cost and the carbon reduction pathway. Producing hydrogen for FCEVs reduces the carbon at the lowest cost, followed by the refinery pathway and then the HCNG pathway (Figure 38). All three costs fall as more renewables are installed, which means that based on the renewable cost assumptions, there is a carbon mitigation benefit for installing on-site renewables.

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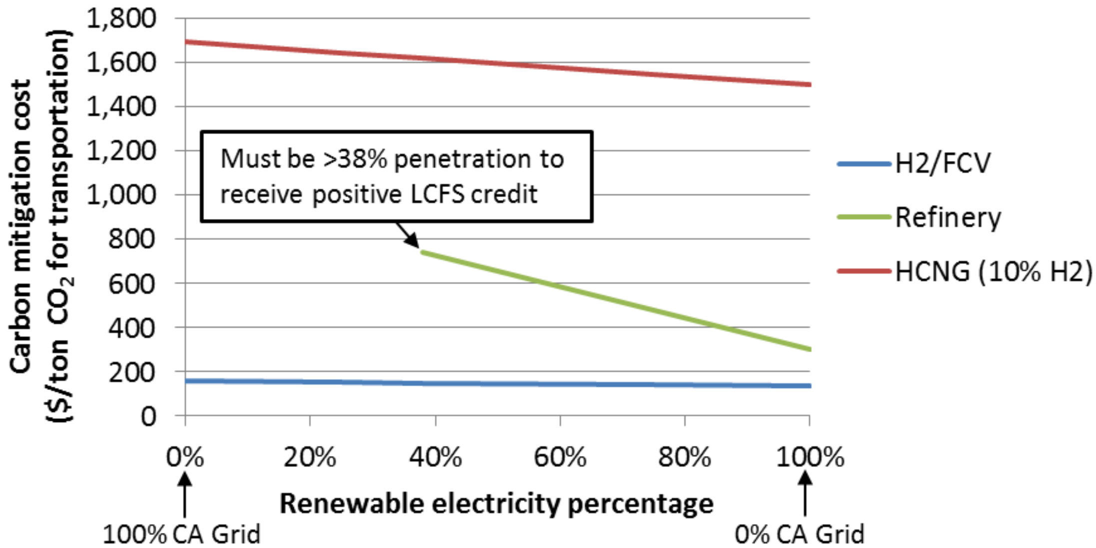

Figure 38. Near-term carbon mitigation cost for each scenario

The previous figure represents the near-term carbon mitigation cost with around 25% renewable penetration; however, California has a renewable target of 50% by 2030. Figure 39 shows the impact on the H_2/FCV pathway for three cases (1) the current grid and renewable cost, (2) the future grid with approximately 50% renewables and current renewable cost, and (3) the future grid and a 25% reduction in the capital cost of the renewables.

A reduction in the grid carbon intensity will improve the cost of all strategies, but, since the LCFS calculations use an average grid carbon intensity, to reach 100% renewable the same amount of renewables must be installed as in the previous figure unless the renewable cost goes down.[25]

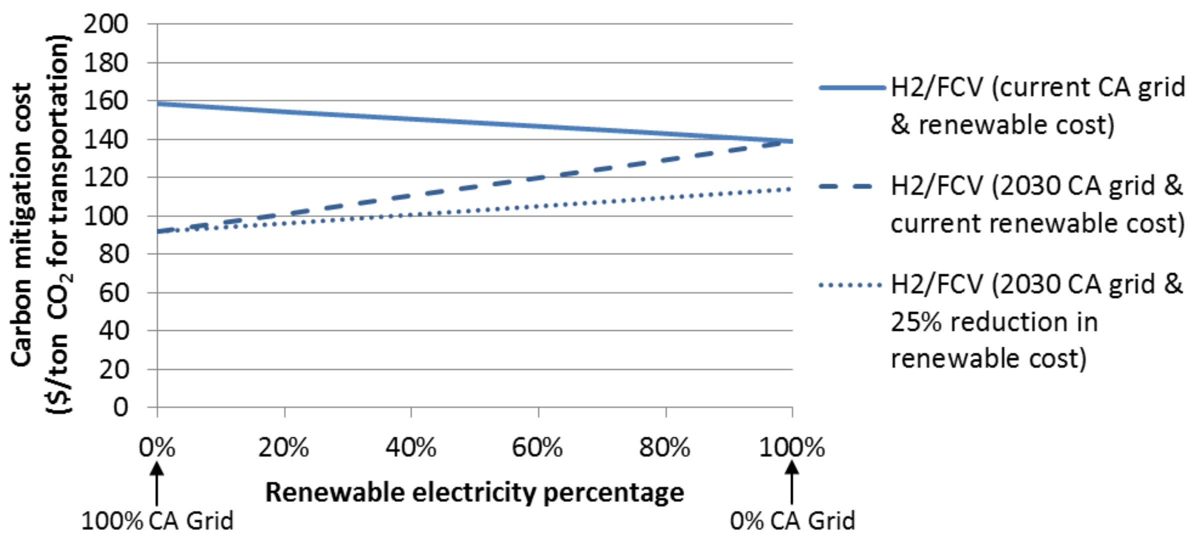

Figure 39. Carbon mitigation cost for FCEV fuel considering the current and future grid

[25] Using an hour-by-hour calculation to consider the renewable content could help to alleviate this issue by encouraging the electrolyzer to turn on only during times when renewable electricity is available. Similarly, the use of marginal emissions rates could also help improve the carbon reduction for flexible electrolysis units.

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The current grid mix encourages the installation of on-site renewables, as is evidenced by the reducing mitigation cost as the renewable percentage increases. Both future grid mix cases result in a lower initial mitigation cost but increases as on-site renewables are installed. This signals that the cost assumptions for renewable generators are not low enough to further reduce the mitigation cost.

8.7.8 Locational Value for Energy Markets

One of the objectives of this report is to find ideal locations for placing electrolyzers. In previous sections, we explored values regionally; because utility rates extend across the entire service territory of a utility there is no impact by changing location within a utility's territory. Similarly, ancillary service prices are not nodal but separated by transmission paths into NP15 (PG&E), and ZP26 and SP15 (SCE and SDG&E). However, the energy market prices are nodal. We collected day-ahead and real-time energy prices for load, aggregate, and zone nodes in California. This resulted in 2,549 nodes that have a complete set of hourly energy market prices. Participation in energy markets is allowed through the PDR product, but the use of the 10-in-10 baseline essentially limits participation of resources to occasional bidding (not constant daily bidding). The potential savings from participation in energy markets is not quantitatively determined in this report but will be explored qualitatively by looking at the energy prices for each node in California. Figure 40 shows the average energy prices for nodes in California. The highest average wholesale energy prices are in the San Joaquin Valley and the lowest prices are in SDG&E territory, despite the higher retail electricity rates shown in Figure 33 and Figure 34. Since each dot represents the average for the year, these figures do not capture the variability or the highest prices but they do provide an approximation of the value that can be received in that location and, more importantly, the regions that of particular value.

Using the PDR product, a demand response device must purchase electricity from the local utility at the retail rate and can bid into energy or ancillary service markets. If the energy price equals or exceeds the bid, the device is called and must reduce its consumption in accordance with the bid. Thus demand response devices typically place bids higher than the opportunity cost of the curtailed consumption. For the case of flexible devices and, in particular, electrolyzers, this presents a challenge. Due to the buffer storage, the system may experience little to no opportunity cost for shifting production from one hour to the next as long as there is sufficient hydrogen to meet customer demands and no inadvertent increase in the demand charge. First, this means that higher electricity prices result in higher revenue for demand response participation in energy markets. Second, there could be multiple times per day and multiple days per week that an electrolyzer might want to bid into the electricity markets apart from high price hours; however, the baseline method for demand response devices makes continuous bidding challenging.

Two methods to alleviate this issue are (1) combine utility and ISO needs into one or more markets to prevent contradictory signals from one or the other and avert double payment for the same load reduction from the utility and ISO, and (2) if the DR owner provides the ISO with the revenue model they are using for device operation, the ISO could review the model and verify that the decision to bid into the energy market is based on a co-optimization of facility, utility, and ISO conditions. While the revenue models are proprietary, the ISO needs some way to verify that the purpose of the load reduction was to support the ISO needs and not to provide a double payment along with a utility payment for the same need.

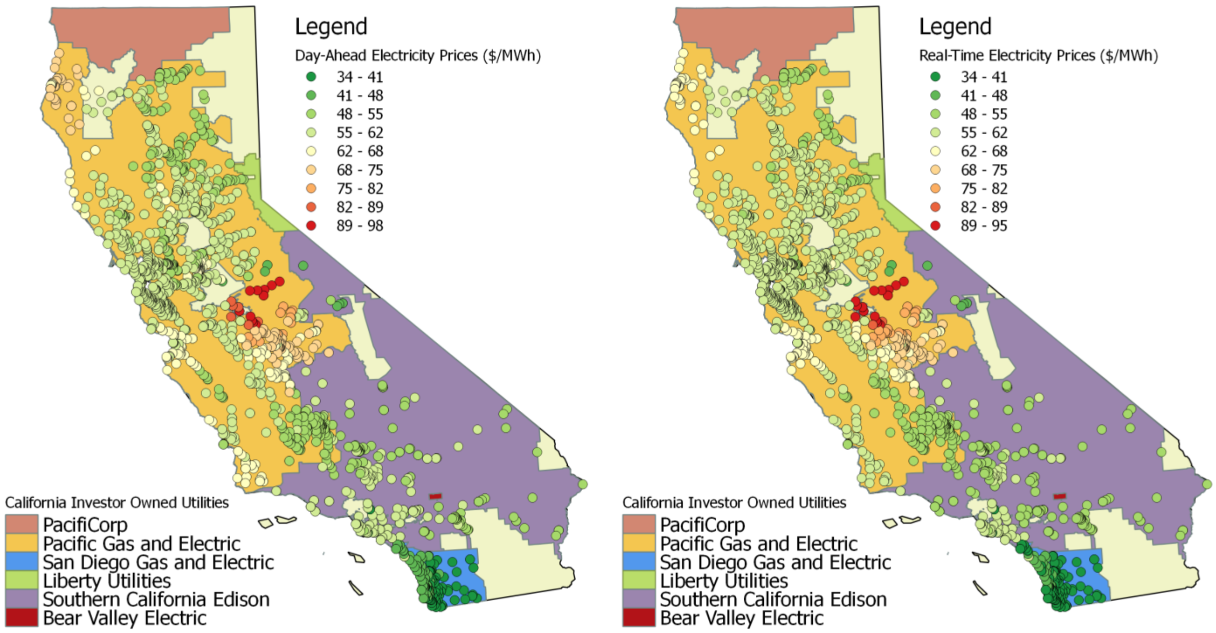

Figure 40. Yearly average nodal energy prices in California for 2015 (left: day-ahead, right: real-time 5min. average)

Because of the range in Figure 40 it is difficult to determine opportunities for siting of equipment in or around areas where hydrogen is consumed. By expanding specific cities we have a better picture of the value of siting hydrogen production facilities. Figure 41 and Figure 42 show an expanded view of the day-ahead energy prices overlaid with hydrogen stations for the Bay Area and Los Angeles Area, respectively. As a reminder, higher prices in an area lead to higher revenue under the PDR. The San Francisco peninsula and the South Bay Area are likely amenable to day-ahead energy market participation from demand response systems due to the high average price. For the Los Angeles Area, territory near Los Angeles County and Orange County (SCE) are favorable regions with high prices, while SDG&E territory has much lower wholesale prices, which will reduce the opportunity for revenue from energy market participation. Participation in real-time energy markets for 2015 resulted in the same trend.

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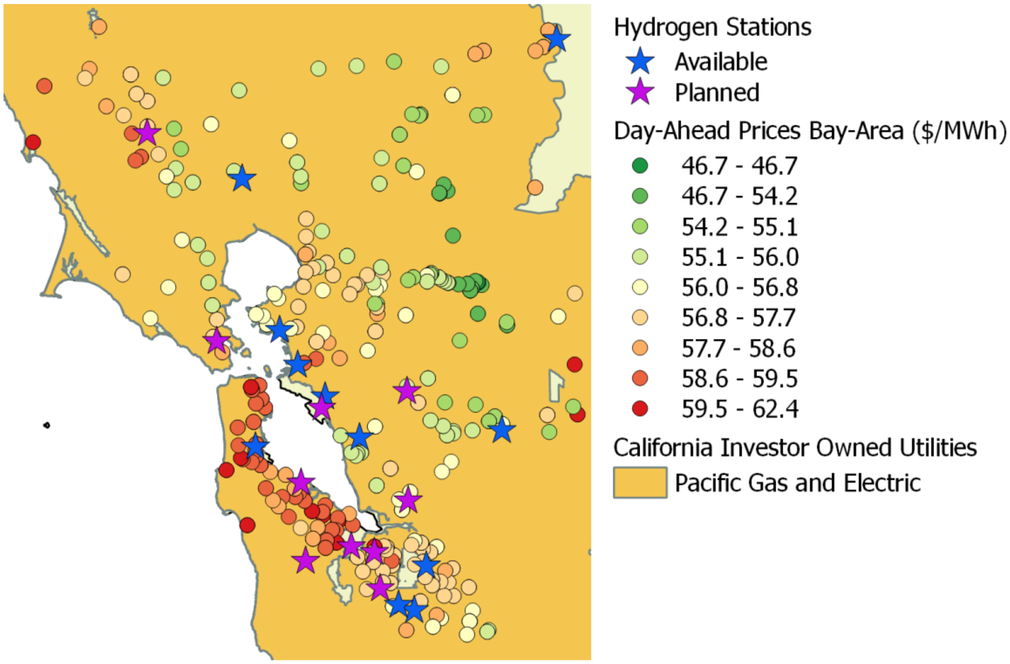

Figure 41. Yearly average day-ahead energy prices in the Bay Area for 2015

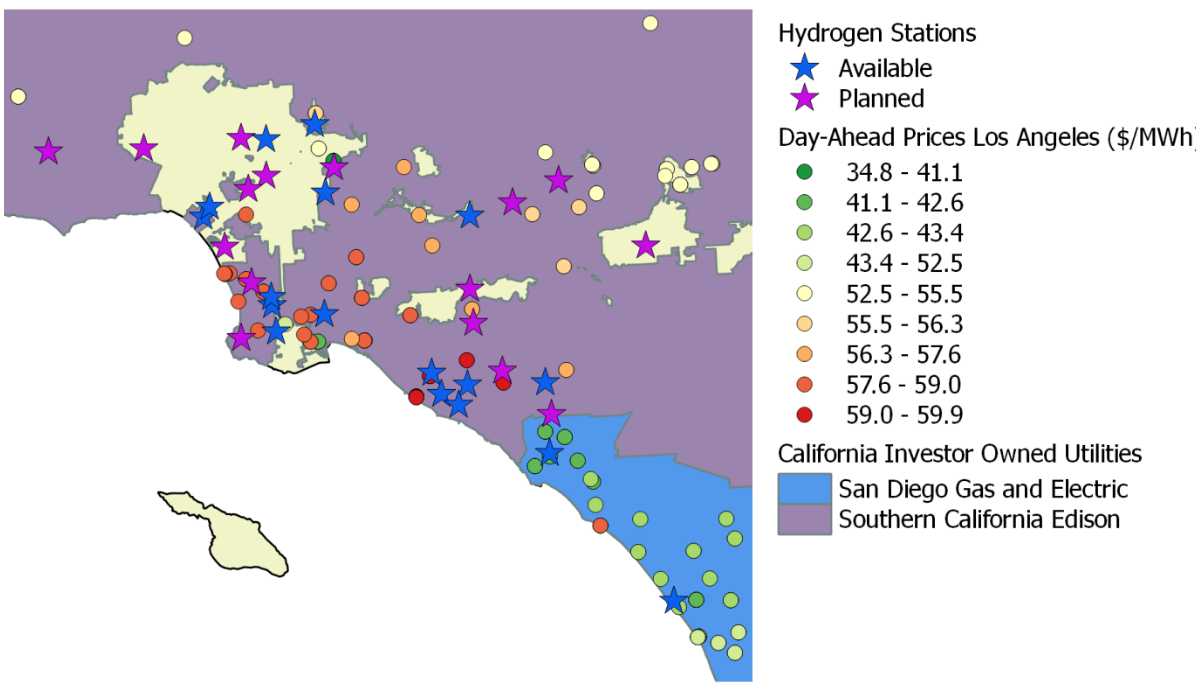

Figure 42. Yearly average day-ahead energy prices in the Los Angeles Area for 2015

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9 Additional Considerations for Electrolyzer Competitiveness

9.1 Current Considerations

The purpose of this study is to identify near-term opportunities for a variety of hydrogen systems. As such, the utility rates, prices, and costs are all assumed to be current. That means that the cost reductions shown here are achievable today. However, the rules and tariffs for market participation that govern demand response devices have many nuances, making them very specific to the configuration and application in which they are being used.

This report explores several specific TOU rates, but rate structures that are designed to better support grid needs by taking better advantage of highly flexible loads represent one near-term option that was not quantified in the previous sections. Real-time pricing rates already exist that have specific energy prices for each hour for retail power. Also, there are rate structures specifically for electric vehicles to encourage a certain charging behavior. The rate structures examined for this report require flexibility to provide the lowest electricity cost operation; however, the price profiles are fixed for multiple hours a day and even the real-time rates do not update based on grid needs. To truly provide the most flexibility, electrolyzers should be bid into day-ahead and real-time energy markets. Due to the baseline rules, it is challenging for a demand response device to simultaneously minimize retail energy and demand charges and maximize benefit from CAISO energy markets. More streamlined participation for demand response devices along with rates structures that are better harmonized with utility and ISO grid needs are two ways that the electrolyzer could better support the grid and receive compensation.

While the rate structures are static day-to-day, there are a number of current demand response programs that allow for compensation for changing behavior during grid events. In this way the demand response is providing a valuable service of resource adequacy; however, electrolyzers and many other devices are capable of providing even greater flexibility than a limited number of events per year, while also providing capacity reduction during event days. New or expanded demand response programs represent another avenue to capitalize on greater flexibility for certain resources.

In calculating the potential revenues from ancillary service markets we consider the ancillary service price for capacity but do not assume that the electrolyzer is ever called by the ISO to provide energy by reducing consumption. Reserves are often called on account of generator outages or other events, which are not easy to predict. If the electrolyzer is providing reserves and the reserves are called to provide energy, then the electrolyzer will receive payment based on the energy price during that time. This can do two things: (1) provide additional revenue not currently accounted for in these results, since it is difficult to predict the number of outages expected; the average yearly energy prices shown in Figure 40 range from $34–98/MWh, and (2) provide reserves and be called to provide energy, which has an associated opportunity cost. When an electrolyzer is called to provide energy, it will have to reduce the hydrogen production, and in order to keep a constant supply it must make that up that reduction at another time. Since reserve events only last a few hours it is not likely an issue for meeting the hydrogen demand, on account of the buffer tank, but it could cause the system to incur additional demand charges. This should be considered when developing a controller for the electrolyzer.

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There are challenges with regular or continuous energy market participation with demand response devices. The PDR allows for market entry but requires that a baseline be established based on several days of historical operating data. If the demand response device sets a very high bid price then it will only be called to reduce energy in limited times and can easily establish its baseline; however, for a flexible device that can provide greater value to the grid by dispatching every day, it would be mutually beneficial to give these devices a method to more actively participate. Additionally, there are challenges with harmonizing participation in electricity markets, minimizing utility rates, and participating in demand response programs. Because utility rates are the same from day to day but the CAISO requirements change each hour, there is a possibility that the signals will be contradictory, meaning that what provides the lowest utility rate is not necessarily the most beneficial behavior for the ISO. The equipment operator must balance all of these elements to determine the best operating strategy. The challenges of demand response ISO market participation and balancing multiple value streams is a topic that needs further exploration. The CAISO has taken several steps to better understand these issues through their ESDER Stakeholder Initiative.

Understanding the marketability and potential for renewable hydrogen is important to developing demand. Senate Bill 1505 in California requires that 33.3% of hydrogen produced for or dispensed by state-funded fueling stations must be made from eligible renewable resources. At present, the majority of the required renewable hydrogen is produced from SMR and coupled with the purchase of biogas credits. The price for biogas credits varies and not much data is available, but based on the DOE's Green Power Markets webpage[26] the residential price premium for retail renewable energy credits is between $1.5/MWh and $15/MWh for nationwide producers that provide biogas. Those prices translate to $2,400–$24,000 per year (for a 1 MW plant with a 90% yearly capacity factor) to achieve 33.3% renewable hydrogen. The cost to produce renewable hydrogen with an electrolyzer is greater than the cost to install an SMR unit and pay the additional fee for renewable biogas credits. While this is the case today, the energy system is changing rapidly so this may not be the case in the future. Some of the prominent factors that can impact the balance between electrolyzer and SMR are (1) the price of natural gas, (2) utility rate structures, (3) electric energy market prices (with greater low-cost renewables), (4) ancillary service market prices (with greater flexibility needed to balance renewable variation), and (5) changes in policy including but not limited to LCFS, RFS, electricity market participation, renewable portfolio standard, and renewable gas standard.

Since biogas credits are relatively inexpensive, we also considered the value of purchasing biogas credits and using them with the electrolyzer to generate LCFS credits. The LCFS credit value for an electrolyzer producing 100% renewable hydrogen for FCEVs is $3.48/kg with an LCFS value of $125/credit. To provide 100% from on-site renewables it would take between 3 and 3.5 MW of wind or solar and cost roughly $5/kg, which brings with it lower energy costs for the electrolyzer. In contrast, it would cost $0.08–$0.8/kg to achieve 100% renewable hydrogen content by purchasing and wheeling biogas at $1.5–$15/MWh. Allowing this pathway would encourage greater biogas use but might produce a situation where all biogas credits are upgrading their value by converting to LCFS credits and not necessarily encourage an increase in new renewables.

[26] DOE's Green Power Market Site (http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=1).

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Renewable variability is not considered in this analysis. We take the historical generation signal and optimize with full knowledge of the renewable profile. For the purpose of integrating renewable power with electrolyzers, one concern could be that a rapid drop in on-site renewable power production will cause a large demand charge. However, previous studies show that the response time of electrolyzer stacks is on the order of seconds (Eichman, 2014). Currently, utility rates calculate the demand charge based on the maximum during any 15-minute metered interval. As a result, we believe that electrolyzer response time is sufficiently fast to accommodate rapid loss of wind or solar power and avoid large demand charges.

9.2 Future Considerations

In all the scenarios explored for this report, the cost per unit of hydrogen produced from SMR is lower than electrolysis derived hydrogen; however, SMR has limited ability to reduce its greenhouse gas emissions. California is actively reducing greenhouse gas emissions with legislation (e.g., Assembly Bill 32). Primary targets have been the electricity and transportation sectors. Greenhouse gas and criteria pollutant emissions from natural gas are more difficult to reduce, particularly in non-electricity sectors including industrial, commercial, and residential. Biogas is a valuable option and should be pursued to support those sectors. In 2014, biogas represented 2.5% of the generation mixture for California (see footnote 20) but there are limits to the amount of biogas that can be produced. Renewable hydrogen from electrolysis can help support carbon reductions in those sectors. Additionally, the flexible operation of electrolysis plants can support the evolution of the energy system as it continues to add more renewables, distributed generation, energy storage, and electric vehicles.

Given the role that renewable hydrogen can play in reducing greenhouse gas emissions, it is important that the power-to-gas and power-to-hydrogen pathways be considered by utilities, ISOs, and regulatory agencies as an option for achieving environmental goals in a variety of sectors while supporting grid operations. This section explores the sensitivity to several cost components and where additional opportunities may exist to impact the cost competitiveness for electrolysis and SMR.

Section 8 described the ability to operate flexibly and the impact of adding renewables and different kinds of delivery methods. All of these have an impact on the cost of hydrogen. In addition, there are other assumptions in this report that impact the cost of producing hydrogen that have yet to be explored. Figure 43 shows the impact of changing several key parameters. The first is the interest rate that was selected. Receiving a lower cost of capital for investment in electrolyzers and renewables—moving from a 7% interest rate to a 5% rate—yields a $0.57 reduction in production cost, representing a 5.8% reduction. The second parameter explores the value of expanding the federal RFS to include electrolyzed hydrogen, which results in a reduction of $0.57/kg or 5.8% from the default value. The third parameter represents the impact of achieving the predictions for electrolyzer cost reductions established in the H2A model[27] for future central hydrogen production (12.3% reduction). The last parameter is the impact of

[27] The total of $3,308 represents $1,414/kW installed and an additional $95/kW-year for FOM and stack replacement. In addition, $1,460 represents $572/kW capital cost for electrolyzer with $44.4/kW FOM per year over a 20-year lifetime.

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increasing the LCFS credit value to $200, the ceiling for the LCFS credit clearance mechanism (10.6% reduction).

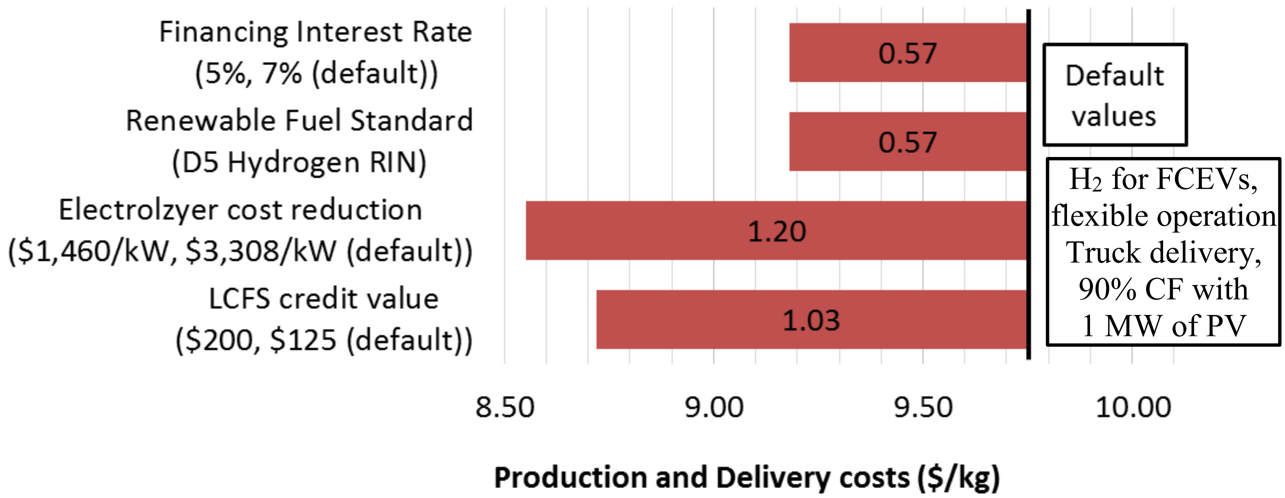

Figure 43. Sensitivity of electrolytic hydrogen cost to several assumptions

A similar exercise is performed for SMR. Reductions in the financing cost follow the same technique (2% interest rate reduction). The impact is a 1.4% reduction in the total production and delivery cost. The capital cost reduction is for the current versus future costs established in the central SMR H2A model[28]. A 25% capital and fixed operation and maintenance cost reduction represents only a 1% reduction in total production cost. Lastly, a sensitivity on the gas price was performed. If the retail price of gas doubles from the 2015 values, the impact is an increase in production and delivery cost over 20% for SMR.

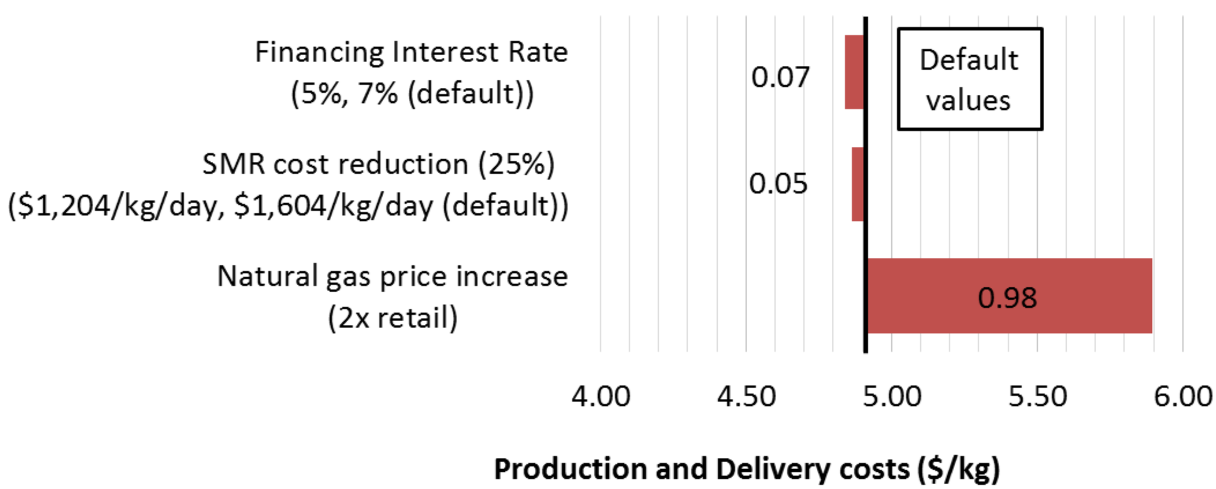

Figure 44. Sensitivity of SMR cost to several assumptions

[28] The default $1,604/kg/day represents $569/kg/day capital, a 1.92 installation cost multiplier, and 4.5% FOM over the assumed 20-year lifetime of the equipment. The amount $1,204 represents $427/kg/day with the same installation and FOM properties as the default.

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9.3 Recommendations for State and Federal Agencies

Specific recommendations to support greater implementation of grid integrated electrolysis equipment have been developed for state and federal agencies. Each item is listed below followed by the relevant organizations.

- Continue activities to lower barriers to demand response participation in electricity markets, and address methods for verifying response (10-in-10 baseline method) and enabling daily use for highly flexible resources. (CPUC, CAISO)

- Explore creation of a dedicated electricity rate for electrolyzers. Plug-in electric vehicles rates can be used as a starting point for designing utility rates that incentivize highly dynamic operation of electrolyzers. (CPUC, utilities)

- Continue to evolve carbon credit markets. The LCFS credit, in general, and pathways including the 100% renewable and the refinery pathway in particular are good examples of developments that expand the opportunities for electrolysis while maintaining fairness for carbon intensity reductions. (ARB)

- Encourage technology advancement and demonstrations, when appropriate, to prove the value for variable operation of electrolysis to support the grid. This report details several near-term techniques for reducing the cost of hydrogen production from electrolysis; however, very few installations are applying any of these advanced strategies to reduce the operation costs of their equipment. Furthermore, equipment has been designed and research has been performed under the assumption that electrolysis should operate nearly constantly to amortize the capital costs as quickly as possible. With the availability of low-cost electricity for consumption during certain periods, the perception of constant operation of electrolysis equipment should be challenged. (CEC, DOE)

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10 Conclusions

The goal for this study is to identify near-term business cases for hydrogen production using electrolysis (power-to-gas and power-to-hydrogen) at specific locations in California. Hydrogen production allows for integration of multiple energy sectors, which can enable greater benefits for each sector. To explore the potential value, we highlighted four scenarios and a collection of sensitivities. The overall cost for each scenario is compared in Figure 45 along with the sale price of hydrogen (red dotted line). In addition to the LCFS credit, there may be additional value from the consumers or the regulators for producing a renewable fuel. This value is unclear and will impact the hydrogen sale price. An illustrative example is shown in Figure 45 with the black dotted line. These results are for flexible operation of a 1 MW electrolyzer operating with a 90% yearly capacity factor and co-located with 1 MW of PV. That combination of properties represents the most profitable of all the configurations explored.

The first and second scenarios consider electrolytic hydrogen produced for use as a fuel for FCEVs, and they differ by their delivery methods—compressed gas in a truck and a hydrogen pipeline, respectively. The value for FCEV fuel and LCFS credits are the highest; however, there is limited demand for these markets presently. The third scenario provides hydrogen for refineries. The electrolyzer is assumed to be near the refinery and using a pipeline to provide hydrogen. Based on the size of current SMR units there is a significant hydrogen demand for refineries, although not necessarily a large growth potential. In practice, there are existing SMR plants at refineries so an electrolyzer could leverage the existing compression and storage equipment, which may be particularly relevant for a demonstration. To get a positive value for LCFS credits, hydrogen for refineries requires greater than 38% renewable penetration, which may present a challenge when installing on-site renewables for both footprint and the time of generation. The last scenario involves using an electrolyzer to produce hydrogen, which is injected into the natural gas pipeline. The pathway is completed by selling the renewable content in the gas to CNG vehicle customers. This enables access to the LCFS credit. Injection into the pipeline represents a very large demand; however, this would require new rules for direct injection of hydrogen or additional equipment cost to methanize the hydrogen before injecting.

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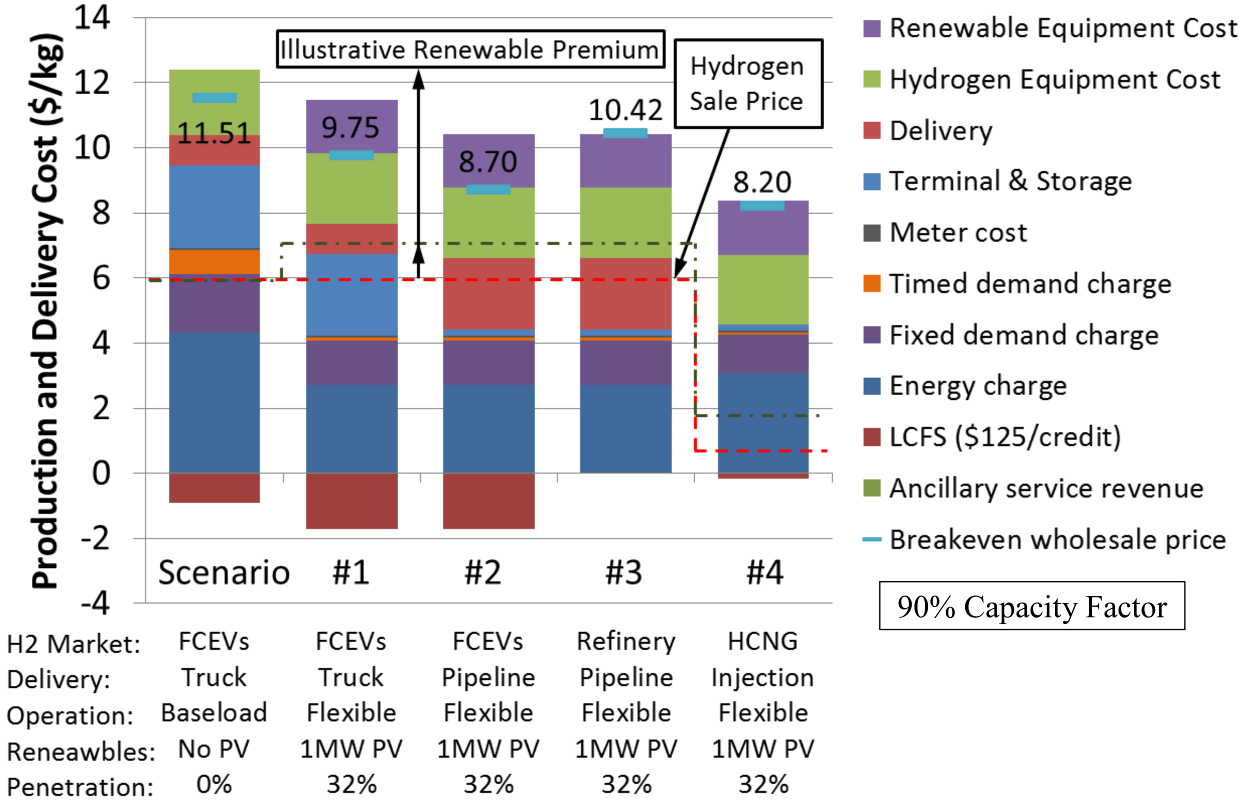

Figure 45. Cost components for flexible hydrogen production scenarios with 1 MW PV

The first two scenarios present the most compelling cases for renewable electrolysis and each has positive and negative attributes. The sale price for FCEVs and refineries was set at the same level based on the delivery methods. Refineries typically have lower cost hydrogen but do not have to provide the same pressure and distance of delivery as for FCEV markets. To make the items comparable we use the same delivery cost estimates for each method (i.e., truck or pipeline).

In the fourth scenario, while it does not have storage and delivery costs (although some blending and/or methanation equipment will likely be required), the sale price for hydrogen as a heating fuel is nearly an order of magnitude lower than for FCEVs or refineries. This makes the business case for scenario four very poor; however, while we did not explore variations of scenario four there are some interesting opportunities to send the injected gas to a combustion generator instead of using it for CNG vehicles, providing long-duration, renewable electricity storage that should be considered for future work.

In terms of locational value, siting in SCE with low utility rates and high ancillary service value is the most beneficial. The second best area to site a renewable electrolysis system is in PG&E territory, which has the second lowest utility rates and access to potentially higher average ISO energy market prices. This may become more relevant as the ISO participation and baseline methodology for demand response evolves to allow for more frequent participation in energy markets. Lastly, SDG&E has the highest utility rates and the lowest average nodal energy market prices, so based on this analysis SDG&E territory is presently the least valuable location for an electrolysis system.

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Trade-offs were explored for varying yearly capacity factors. A lower-capacity factor results in lower-cost electricity, but since less hydrogen is sold, capital costs must be spread over less revenue. Given current utility rates, the optimal capacity factor was determined to be around 90% with and without renewables.

Establishing a near-term business case based on the availability of excess renewable generation does not seem likely due to uncertainty regarding the number of hours and total available energy and instead should be considered complementary to the other techniques detailed in this report.

Water consumption for electrolysis is strongly dependent on the mixture of resources. It was found that the largest component of water consumption was from electricity generation. The water consumption for electrolysis using 100% renewable sources is 9.2 gal/kg. Using the 2014 California grid, the water consumption is around 67 gal/kg for electrolysis and 4.9 gal/kg for SMR.

A variety of components contribute to the cost reductions detailed in this report. These components include options that are near-term, currently available, and longer-term. The near-term items include flexible operation, the addition of on-site renewables, demand response programs (not included in Figure 45), and reserve payments (not included in Figure 45). The longer-term items include lower cost of capital, electrolyzer cost reduction, availability of RFS credit pathways, and a change in the LCFS value. Figure 46 depicts the magnitude of each component.

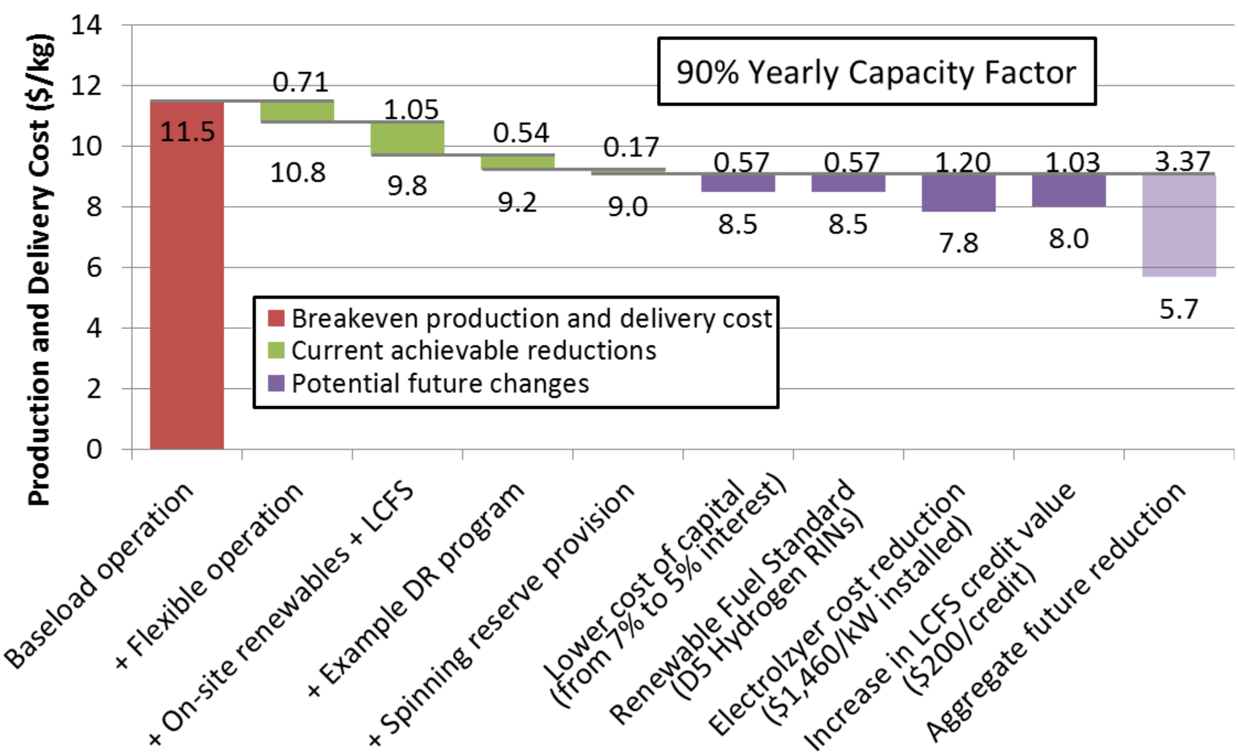

Figure 46. Summary cost impact of electrolytic hydrogen production for use in FCEVs with truck delivery (average across all IOUs)

The following summaries are provided for each of the items in Figure 46:

- Flexible operation involves changing the power consumption to avoid high energy and demand charges. This reduces the production and delivery cost by 6%–7% from the baseload cost. This value is based on current California IOU TOU rates and will change based on any changes to the TOU rates or participation in real-time pricing or other utility rates.

- The addition of on-site renewables can further reduce the energy and demand charges, particularly for PV, as well as increase the renewable content of the hydrogen thereby increasing the number of LCFS credits obtained. Even after purchasing renewable capacity the total cost of producing and delivering hydrogen is reduced by 7% and 10%, respectively, using California utility rates and an LCFS credit value of $125. The reduction to TOU energy and demand charges would not be available if renewable electrons are wheeled to the site and the renewable capacity is not on the same utility meter as the electrolyzer. With flexible operation, having renewables behind the same meter provides the greatest benefit.

- A flexible load can participate in a variety of programs with California's utilities. Most programs are for resource adequacy and require a load reduction for specific events called by the utility or grid system operator. These events can occur as little as once per year or as often as several dozen times per year and are triggered by a variety of conditions, including system operator load forecast, temperature, generation resource inadequacies, and ISO or utility T&D reliability need. Several programs for PG&E are examined (i.e., BIP, CBP, CPP and DBP), and the demand response program value is up to $0.54/kg (5% reduction) for the BIP program with a 1-MW electrolyzer operating flexibly at 90% yearly capacity factor and 1 MW on-site PV.

- The last of the currently achievable items is value in reserve markets. The CAISO allows demand response to participate in energy or ancillary service markets (e.g., PDR and RDRR). The CAISO is currently facilitating a stakeholder process (ESDER phase 2) with the goal of lowering the barriers for grid-connected storage and distributed energy resources to participate in ISO markets. Presently the equipment and baseline method for participation limits the benefit that demand response receives from market participation. As a result, we focus only on ancillary services and find that provision of spinning reserve capacity can provide 1%–2% reduction in cost. In addition, this assessment does not include energy payments that would be received when the reserve is called by the ISO, which could increase the overall reduction.

The longer-term, currently unavailable options are described below. Each item can be pursued independently, and the final bar in Figure 46 shows the aggregate impact that would result if all items are realized.

- Lower cost of capital can reduce the cost for electrolysis equipment. To show the relative impacts for receiving lower cost of capital the interest rate on debt was reduced from 7% to 5%, resulting in nearly a 5% reduction on overall hydrogen cost.

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- At present, hydrogen using a renewable electrolysis pathway is not eligible for RFS credits. If a pathway for renewable hydrogen produced from electrolysis was added to the RFS, electrolyzers could receive \$0.44/kg for D6 RINs or \$0.57/kg for D5 RINs. That reduction represents 4%–5% from baseload cost.

- Lowering the cost for the electrolyzer, balance of plant, installation, and maintenance can all help to improve the competitiveness for electrolyzer systems. A capital cost reduction of nearly 56% down to \$1,460/kW (includes installation and fixed operation and maintenance[27]) results in a cost reduction of \$1.2/kg (10.44%).

- The LCFS credit incentivizes the adoption of low carbon transportation fuels. LCFS credits at \$125/credit provide up to \$3.48/kg depending on the fuel pathway and renewable penetration selected. Increasing the credit value from \$125 to \$200/credit yields an increase in revenue higher than \$1/kg (9%).

Compared to the conventional baseload operation strategy, the near-term achievable cost reductions amount to 21%. When combined with future potential reductions the total is 51%. In comparison to SMR, similar reductions in the costs of capital and equipment would result in a 2.3% reduction in production and delivery cost. However, a doubling of the price of natural gas from the 2015 values would increase the cost of SMR more than 20%.

The proposed flexible operation and more active participation in electricity markets for electrolyzers have the potential to provide a reduction in the cost of hydrogen from electrolysis. The cost reduction can be experienced with no impact on the hydrogen supply to customers. Additionally, there are a variety of future opportunities to further reduce the cost for these systems. Some of the future opportunities, including new utility rates and energy market participation, were not quantified while RFS eligibility, LCFS credit value, cost of capital, and system cost reductions were considered.

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11 Future Work

For this study there are many other configurations and pathway permutations that were not considered. We selected the most likely near-term pathways and have shown that, by changing from baseload operation to a more flexible operation to take advantage of utility rates, and by providing even the most basic level of integration with utility demand response programs or CAISO markets, there is a significant amount of cost reduction that can be realized. Given the understanding developed through this work there are other pathways that are of interest. Additionally, this study focused on stand-alone central or partially distributed hydrogen production; however, there are challenges with reaching 100% renewable energy under these assumptions that require either net metering or co-location at a larger facility. It would be beneficial to explore the value that an electrolyzer could provide for demand side management at larger facilities that could enable integration with more renewables.

One of the assumptions for this study is that cycling an electrolyzer has a negligible impact on the equipment lifetime. The accuracy of this assumption is important for understanding the additional cost implications for cycling an electrolyzer. Future work should be done to quantify the impact of variable operation on electrolyzer lifetime.

HDSAM is used for delivery cost predictions and isolates the cost for individual cities; however, there will be trade-offs for the hydrogen distribution network within a city between truck delivery or pipeline, for example. A detailed locational analysis of hydrogen delivery options should be pursued to isolate the additional value from delivery methods. As an example, the Scenario Evaluation, Regionalization & Analysis (SERA) tool could be combined with the current analysis to look at locational delivery value opportunities.

The electrolyzer system efficiency changes at each load point. At present, a single efficiency is used to represent the electrolyzer. NREL has done testing on electrolyzers and has stack and system efficiency curves that can be put into the model to more closely represent electrolyzer behavior. This could also be used to help determine what kind of changes to the system efficiency (e.g., balance-of-plant components) would be helpful from an economic competitiveness point-of-view that would not be obvious otherwise.

Utility connections where the customer connects at higher voltage receive a lower energy cost; however, this means that the customer potentially has to purchase more expensive equipment to connect at that voltage level. This report has shown that a lower energy cost is received but has not looked at opportunities for stack configuration or the cost of providing additional electrical equipment to connect at higher voltage levels.

Several specific TOU utility rates were selected for this analysis. These utility rates are for typical commercial or industrial customers with greater than 1 MW of load. As discussed, there are new utility rates for plug-in electric vehicles to incentivize a certain behavior, and there are also real-time pricing rates that require a greater level of equipment control than TOU rates. Since electrolyzers are a highly flexible load and because of the importance of the energy cost in the hydrogen price for electrolysis, future work should include an analysis of the value of existing rates and propose potential new utility rates that can better utilize the fast response of electrolyzers. There are other ownership models that should be explored (e.g., utilities owned assets) that would greatly impact the operation and economic feasibility of the equipment.

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