Optimizing an Integrated Renewable-Electrolysis System

Josh Eichman, Mariya Koleva, Omar J. Guerra, and Brady McLaughlin

National Renewable Energy Laboratory

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List of Acronyms

AC	Alternating current
CAISO	California Independent System Operator
DC	Direct current
EY	Electrolyzer
FERC	Federal Energy Regulatory Commission
FOM	Fixed operation and maintenance
FCEV	Fuel cell electric vehicle
ITC	Investment tax credit
LCFS	Low Carbon Fuel Standard
MACRS	Modified Accelerated Cost Recovery System
NEM	Net energy metering
NGR	Non-generator resource
NREL	National Renewable Energy Laboratory
PDR	Proxy demand resource
PG&E	Pacific Gas and Electric
PV	Photovoltaic
REC	Renewable energy credit
RODeO	Revenue Operation and Device Optimization Model
SMR	Steam Methane Reforming
WACC	Weighted average cost of capital

Executive Summary

Hydrogen is a versatile energy carrier that is used in a wide variety of chemical and industrial processes. Producing hydrogen using electrolysis can enable integration of multiple sectors including electricity, heating, and industrial sectors; however, the cost of producing hydrogen from electrolysis remains a challenge for encouraging greater adoption. With growing amounts of renewable generation on the California grid, there is downward pressure on wholesale electricity prices, particularly during the afternoon when abundant electricity from photovoltaics (PV) is available. These lower, or even potentially negative, prices challenge the business cases for new and existing PV plants.[1] In addition, as the grid transitions to greater levels of wind and solar resources which are less flexible than the current generation resources, there is greater need for other sources of system flexibility.[2]

To help improve the economics for both solar PV and hydrogen production using electrolyzers, we explore the benefit of combining PV and electrolysis systems. The optimal breakeven hydrogen production cost[i] for six unique market participation configurations is calculated at six candidate locations owned by Pacific Gas and Electric (PG&E), where PV is already installed. The six market configurations are depicted in Figure ES-1 and include islanded, separated, retail, net energy metering (NEM), hybrid retail/wholesale, and wholesale.

This work was developed as part of the U.S. Department of Energy's H2@Scale consortium activities (https://www.energy.gov/eere/fuelcells/h2scale) under a cooperative research and development agreement (CRADA) with Pacific Gas and Electric Corporation and the Fuel Cell Technologies Office of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy.

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[i] Breakeven cost includes equipment capital costs, operation and maintenance costs, financing costs, and taxes as well as any additional revenue streams but does not include any profit. As such breakeven cost represents a lower bound on the cost to provide products and services.

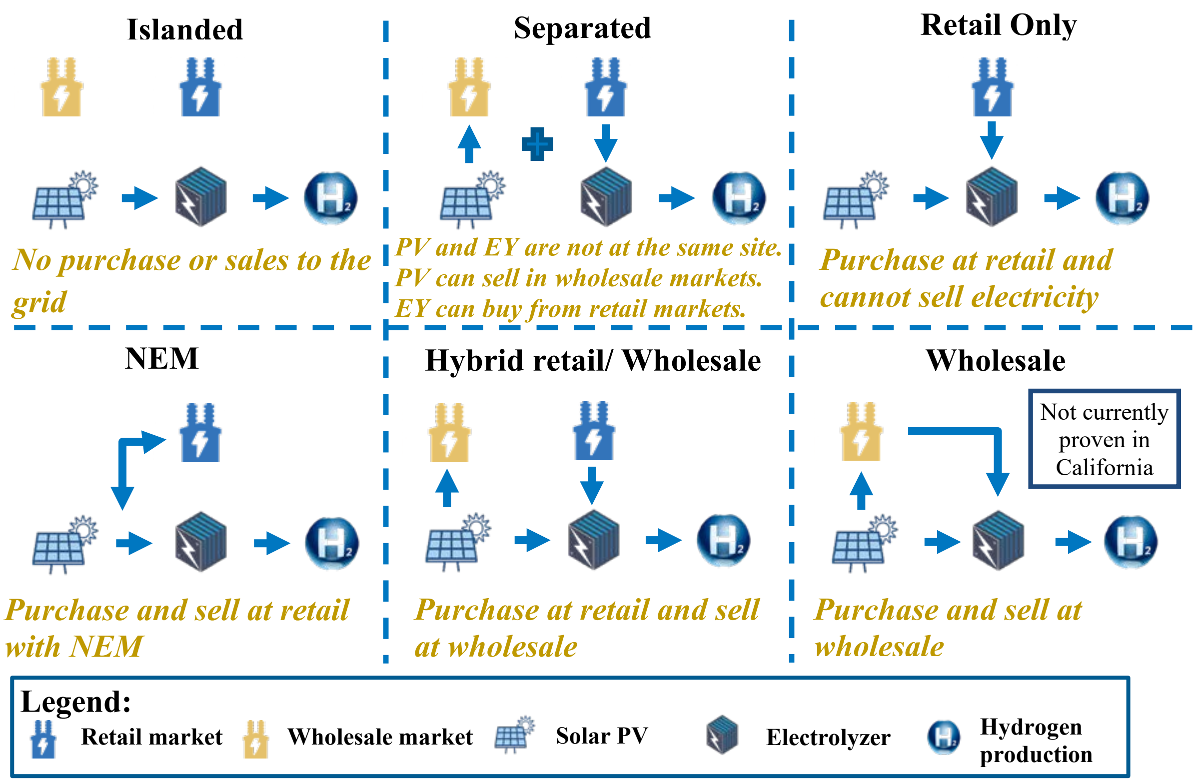

Figure ES-1. PV + Electrolysis market configurations

Using the Revenue Operation and Device Optimization Model (RODeO) model, the optimal breakeven hydrogen price over the lifetime of the equipment is calculated.[3–6] Costs include production, storage, and compression in preparation for gaseous delivery trucks. Revenue streams included in the optimization are the sale of hydrogen, Low Carbon Fuel Standard (LCFS) credits, renewable electricity sold to the grid, and Renewable Energy Credits (REC). The costs included are the electricity costs, capital and fixed operation and maintenance cost (FOM) for the electrolyzer, PV, and storage and compression systems as well as taxes and financing costs. In addition, cost reductions are achieved through retail and wholesale electricity use optimization, by which electricity is purchased at the lowest price and sold, if possible, at the highest price.

The resulting breakeven hydrogen production costs for each location and configuration are presented in Figure ES-2. These results use current costs for PV from the annual technology baseline[7] and electrolyzer system costs from the DOE H2A model.[8] For all locations, the breakeven hydrogen production cost results show that, in order of decreasing cost, the system configurations are islanded (highest), separated, NEM, retail, hybrid retail/wholesale, and wholesale (lowest).

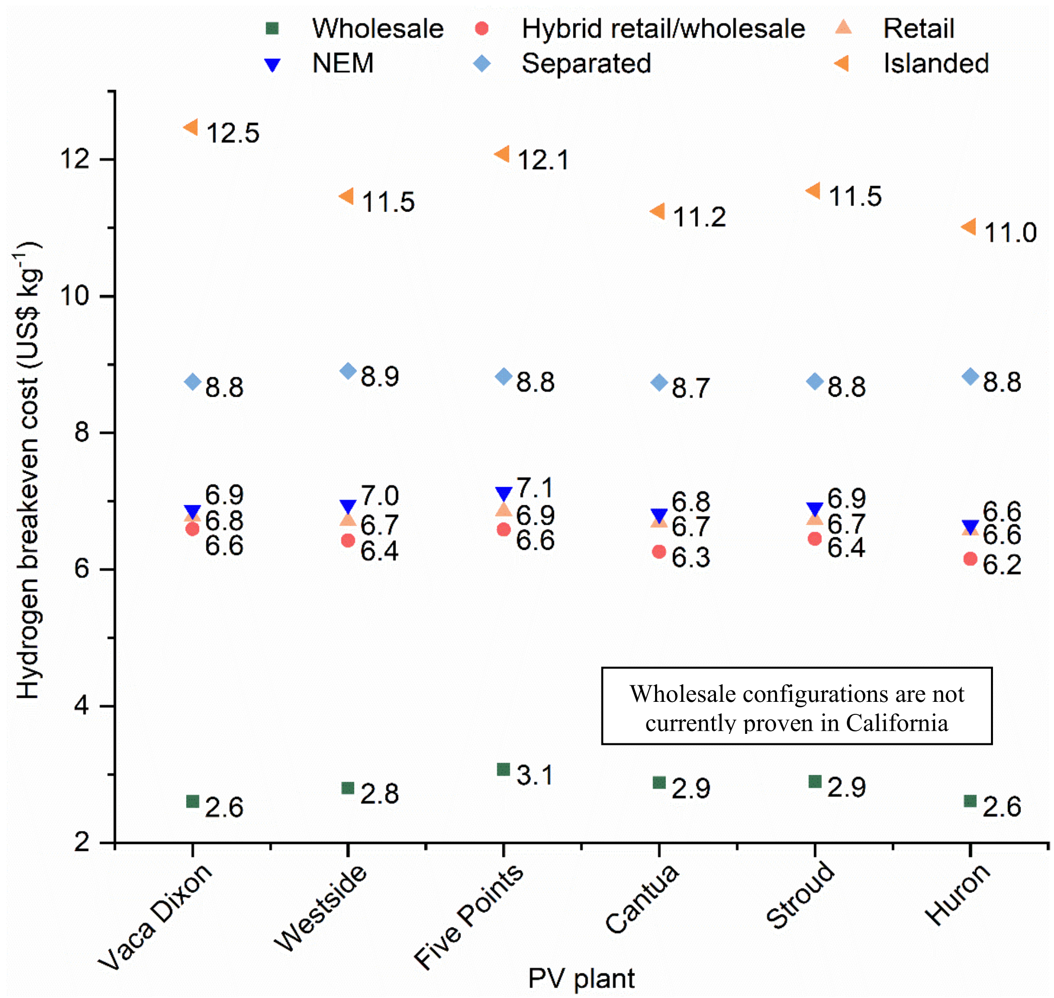

Figure ES-2. Current hydrogen breakeven production cost for PV + Electrolysis systems with six market configurations and six candidate locations

While most of the results are intuitive, it is worth describing a few specific results. First, there is clustering of the NEM, retail, and hybrid retail/wholesale configurations, because they all rely on retail purchase of electricity, while the islanded and wholesale configurations do not.

Second, the NEM scenario is more costly than the retail scenario. NEM requires that the renewable installed capacity is less than or equal to the on-site load. As a result, there are never any times that excess generation is available, because the renewable electrons are the lowest cost and the electrolyzer has enough capacity to use all of them. NEM rates are beneficial for loads that are not flexible where the system may have excess generation.

While there are no electricity costs for the islanded configuration, the reduced utilization of the electrolyzer, caused by limited hours of PV production, results in the highest breakeven cost. The separated configuration provides a comparison point for the cost of operating both systems independently with a cost of $8.8/kg. Excluding islanded systems, integration of PV and electrolysis reduces the costs from an average across all six sites. This reduction is from $8.8/kg to around $6.7/kg for the NEM, retail, and hybrid configurations and to around $2.8/kg for the wholesale configuration. Wholesale market access for flexible loads for all hours of the day in

California is not currently proven. While there are several programs in California that allow device access to wholesale markets (direct access, NGR, PDR), none are either open or give flexible loads sufficient exposure to wholesale markets. The most promising way to access wholesale prices is for electrolyzers to work with a load-serving entity, electricity service provider or similar entity to make bulk power purchases.

A breakdown of the cost components for a specific site, Vaca-Dixon, is presented in Figure ES-3. Using current estimates for cost and market conditions, these values represent the breakeven cost for hydrogen that must be received over the lifetime of the equipment. For each of the configurations, there is a balance between the capital and maintenance cost components, the operation costs (i.e., electricity costs) and the additional market revenues. Depending on the cost or value for each of those components the size and utilization, or equivalently capacity factor (CF), of the equipment changes to minimize the breakeven hydrogen production cost. These results show that greater integration with the grid improves the competitiveness of the combined system, largely by reducing the cost of electricity.

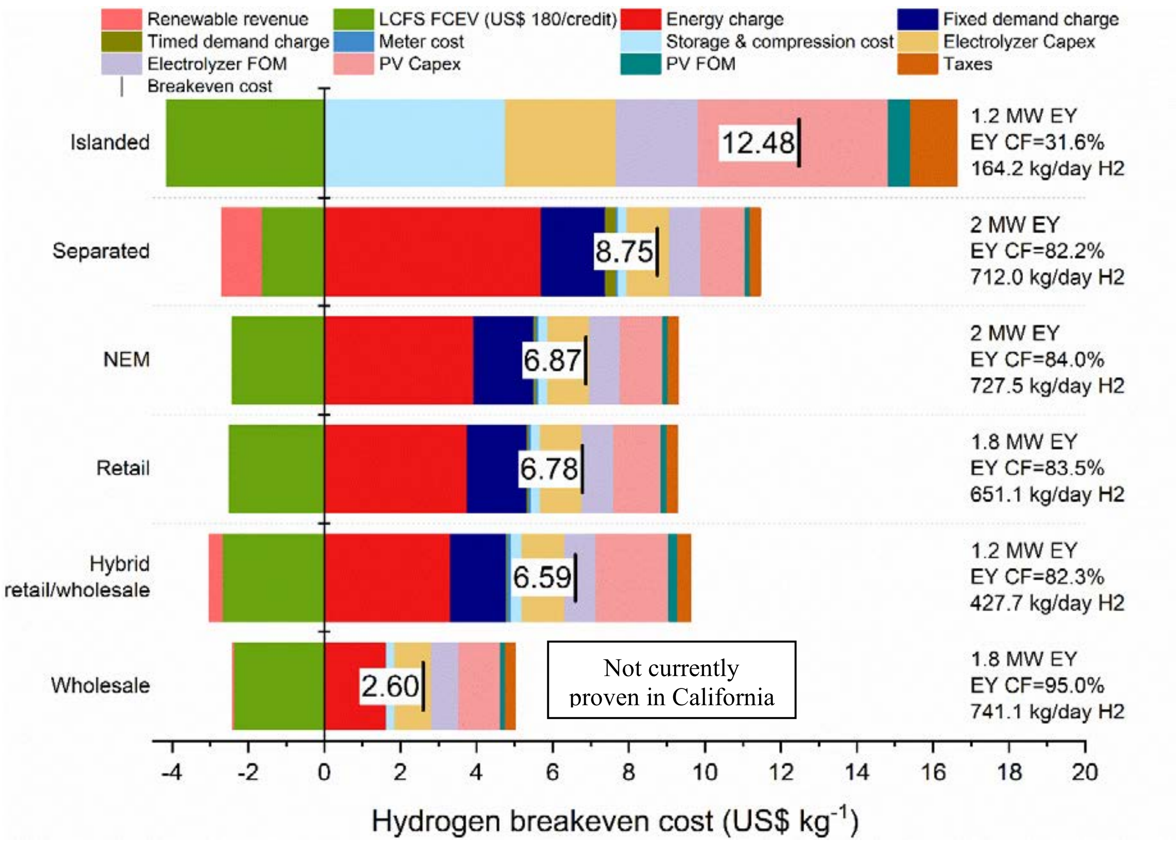

Figure ES-3. Comparison of current breakeven hydrogen production cost for Vaca-Dixon with 2MW of PV. EY = Electrolyzer, CF= Capacity Factor

The integration of solar PV and electrolysis is shown to provide a mutually beneficial relationship, both operational and economic. With the exception of the islanded system, when PV and electrolysis are integrated, the breakeven cost for producing hydrogen reduces between 20% (NEM) and 70% (wholesale). For PV, integration with electrolysis offers the potential to hedge against wholesale market price volatility, particularly in a future with additional PV putting downward pressure on wholesale prices in the afternoon. Additionally, integration with electrolysis may offer the potential to defer or avoid transmission investment to deliver power to the point-of-use and instead use it on-site.

The optimal system designs for NEM, retail only, hybrid retail/wholesale and wholesale have renewable penetrations from 47% to 59%. That means there is a renewable penetration in that range that represents the lowest cost system. This has interesting implications for existing programs and future legislation. Because there is an economic opportunity to pursue high renewable systems, that could mean that encouraging production facilities to produce some fraction of renewable hydrogen in California, on the order of 50%, would not negatively impact project economics and may actually lower the cost. This has consequences for legislation like SB1505 the LCFS program or future legislation.

This report also explores what is meant by cost-competitiveness for hydrogen. Beyond the base cost to produce hydrogen, there are other factors that can affect the competitiveness. Hydrogen supply shortages can change the accepted hydrogen purchase price. Additionally, customers may be willing to pay a premium for hydrogen that is renewable. To better understand renewable hydrogen premiums, we four different alternative techniques to produce renewable hydrogen were examined (i.e., purchasing unbundled RECs, bundled RECs, carbon capture and sequestration and biomass fed steam methane reformer (SMR)). The premium for renewable hydrogen ranges between $0.04/kg and $2.38/kg.

When compared with natural gas SMR without considering any renewable hydrogen premiums, this study finds that PV + Electrolysis systems with current costs are likely not competitive; however, with cost reductions for electrolysis equipment consistent with DOE projections, it was found that systems with wholesale market access would be competitive, largely on account of both low capital costs and low-cost electricity. The electrolysis units can provide greater flexibility than is required based on retail rate optimization, so there is an opportunity for a utility or CAISO to increase system flexibility with PV + Electrolysis systems in return for commensurate compensation. In this way, there are potentially several solutions that fall between the hybrid configuration and the wholesale configuration that could provide sufficient compensation for a PV + Electrolysis unit to compete with SMR while also providing greater flexibility to the grid.

Table of Contents

1 Introduction **1**
2 Strategy for Modeling PV + Electrolysis **2**
2.1 Market Configurations 2
2.2 Optimization Model 4
3 Candidate Locations for PV + Electrolysis **6**
4 Input Data and Assumptions **7**
4.1 PV Technical Properties 7
4.2 Electrolyzer and Compressor Technical Properties 10
4.3 Electricity Costs 12
4.3.1 Retail 12
4.3.2 NEM 12
4.3.3 Wholesale 13
4.4 Cost Parameters 15
4.5 Financing Properties 16
4.5.1 Depreciation 16
4.6 Credits and Incentives 16
4.6.1 Low Carbon Fuel Standard 17
4.6.2 Renewable Energy Credits 18
4.6.3 Investment Tax Credit (ITC) 19
4.6.4 State Tax Credits 20
5 PV + EY Results **22**
5.1 Discussion 23
5.2 Electrolyzer Operation Profiles 28
5.3 Renewable Hydrogen and Curtailment 29
5.4 Additional Sensitivity Analyses 32
5.5 Value Streams Considered and Not Considered 33
5.6 Considerations for Site Selection 35
5.7 Putting the Results in Context 39
6 Conclusions **43**
7 Future Work **47**
References **48**
Appendix A. Breakeven Hydrogen Production Cost Bar Charts for Other Locations **51**

List of Figures

Figure ES-1. PV + Electrolysis market configurations ... vi
Figure ES-2. Current hydrogen breakeven production cost for PV + Electrolysis systems with six market configurations and six candidate locations ... vii
Figure ES-3. Comparison of current breakeven hydrogen production cost for Vaca-Dixon with 2MW of PV. EY = Electrolyzer, CF= Capacity Factor ... viii
Figure 1. PV + Electrolysis market configurations ... 2
Figure 2. RODeO model flowchart ... 5
Figure 3. Location of selected solar power stations in California ... 6
Figure 4. Average daily PV profile for each candidate site in 2016 ... 8
Figure 5. Annual capacity factors for candidate PV locations from 1998 – 2016. ... 9
Figure 6. Monthly solar power production from 1998 - 2016 for selected locations in California ... 10
Figure 7. Compressor flowrate and cost (original 2009$ and updated to 2018$) relationship curve ... 11
Figure 8. LMP for 2016 at the generation nodes closest to each candidate location. ... 14
Figure 9. Average 2016 Wholesale LMP price range and average for all 6 solar sites[18] ... 14
Figure 10. LCFS historical price and volume curves[21] ... 17
Figure 11. LCFS value for FCEV fueling from electrolysis pathway given three sets of assumptions ... 18
Figure 12. Level of ITC for PV ... 20
Figure 13. Comparison of current breakeven hydrogen production cost for Vaca-Dixon with 2 MW of PV ... 22
Figure 14. Comparison of current total breakeven hydrogen production costs across all locations ... 23
Figure 15. Hydrogen breakeven production cost breakdown for different storage durations with a 1 MW EY and 2 MW PV at Vaca-Dixon ... 24
Figure 16. Comparison of average electricity price received at Vaca-Dixon for each scenario ... 27
Figure 17. Comparison of electricity costs to total system costs at Vaca-Dixon for each scenario ... 28
Figure 18. Average daily electrolyzer operation profiles at Vaca-Dixon for utility rate period A (Summer) ... 29
Figure 19. Average daily electrolyzer operation profiles at Vaca-Dixon for utility rate period B (Winter) ... 29
Figure 20. Hydrogen renewable content considering either the PV production or the PV production and California 2016 grid mixture for each configuration ... 30
Figure 21. Comparison of curtailment and fraction of PV curtailed for each configuration ... 31
Figure 22. Example demonstrating how oversizing PV can impact electrolyzer plant operation ... 31
Figure 23. Tornado chart examining sensitivities to hydrogen production price for the Vaca-Dixon hybrid system configuration ... 32
Figure 24. 2016 Day-ahead average electricity prices for California generation nodes[18] ... 35
Figure 25. Map of current and planned hydrogen stations in California[35] ... 36
Figure 26. California Direct Normal Solar Resource ... 37
Figure 27. California electric transmission network (left) and natural gas network (right)[36] ... 38
Figure 28. Comparison of PV + Electrolysis and current SMR breakeven hydrogen production cost results inflated to 2017 and with additional costs to prepare the hydrogen for truck delivery ... 40
Figure 29. Comparison of breakeven hydrogen production cost for Stroud with 20 MW of PV ... 51
Figure 30. Comparison of breakeven hydrogen production cost for Huron with 20 MW of PV ... 52
Figure 31. Comparison of breakeven hydrogen production cost for Five Points with 15 MW of PV ... 53
Figure 32. Comparison of breakeven hydrogen production cost for Cantua with 20 MW of PV ... 54
Figure 33. Comparison of breakeven hydrogen production cost for Westside with 15 MW of PV ... 55

List of Tables

Table 1. Technical Specifications for the Selected Solar Systems[14] ... 6
Table 2. Location Data for Selected Solar Sites[14] ... 7
Table 3. Technical Specifications for PV and Electrolyzer Systems ... 11
Table 4. Summary of Retail and Wholesale Rate Properties ... 12
Table 5. Summary of Generation Nodes Selected for Each Site ... 13
Table 6. Transmission and Distribution Components from E-20 Rate ... 15
Table 7. Cost Parameters for Each Technology ... 15
Table 8. Assumptions for Financial Properties ... 16
Table 9. Summary of Assumptions for Credit and Incentives ... 17
Table 10. Potential State Tax Credits, Exemptions, and Exclusions for PV + Electrolysis Systems ... 21
Table 11. Hydrogen Cost for Production and Preparation for Delivery Inflated to 2017$[8] ... 39
Table 12. Potential Premium Values for Converting Hydrogen from Natural Gas SMR to a Renewable or Carbon Free Product ... 41

1 Introduction

Hydrogen is a versatile energy carrier that is used in a wide variety of chemical and industrial processes. Producing hydrogen using electrolysis can enable integration of multiple sectors including electricity, heating, and industrial.[9] While there are potentially growing markets for hydrogen in California including for fuel cell electric vehicles and materials handling equipment, the cost for producing hydrogen from electrolysis is typically higher than the main incumbent technology, Steam Methane Reforming (SMR) of natural gas, which has resulted in limited adoption of electrolysis.[8,10]

With growing amounts of renewable generation on the California grid, which is near-zero marginal cost, there is downward pressure on wholesale electricity prices, particularly during the afternoon from photovoltaics (PV). These lower, or even negative prices, challenge the business cases for new and existing PV plants. In addition, as the grid transitions to greater levels of wind and solar resources which are less flexible than the current generation resources, there is greater need for other sources of system flexibility.[2] Hydrogen production has been shown to be one of the options for providing additional flexibility to the grid.[11]

Integrating hydrogen production equipment with renewables offers an opportunity to increase the cost effectiveness of both technologies. For renewables, this results from market diversification for the sale of electricity by having the ability to sell to the electrolyzer. This also relieves some of the downward market price pressure caused by installing lots of PV with coincident electricity production profiles. Similarly, integration with renewables has the potential to reduce electricity costs for hydrogen production and leverage multi-market arbitrage opportunities. Multi-market arbitrage is valuable because, by engaging multiple potential markets, electrolyzers can sell hydrogen to the highest valued market at any given time to maximize revenue and minimize the sale price.

The first objective of this study is to holistically model the various value streams created by an integrated PV + Electrolysis system that produces hydrogen for use in the transportation sector. The second objective is to use that model to design an optimized integrated PV + Electrolysis system with an overall goal of characterizing the potential value for PV + Electrolysis systems for different equipment configurations, locations, and sizing.

2 Strategy for Modeling PV + Electrolysis

Modeling combined PV and electrolyzer systems requires an understanding of each technology and how they integrate into available markets. First, the most promising market configurations for PV + Electrolysis are introduced. This is followed by a description of the modeling framework used to analyze these market configurations.

2.1 Market Configurations

While there are many possible market configurations for renewables and electrolysis, the six market configurations considered are depicted in Figure 1. The merits of each configuration are described below.

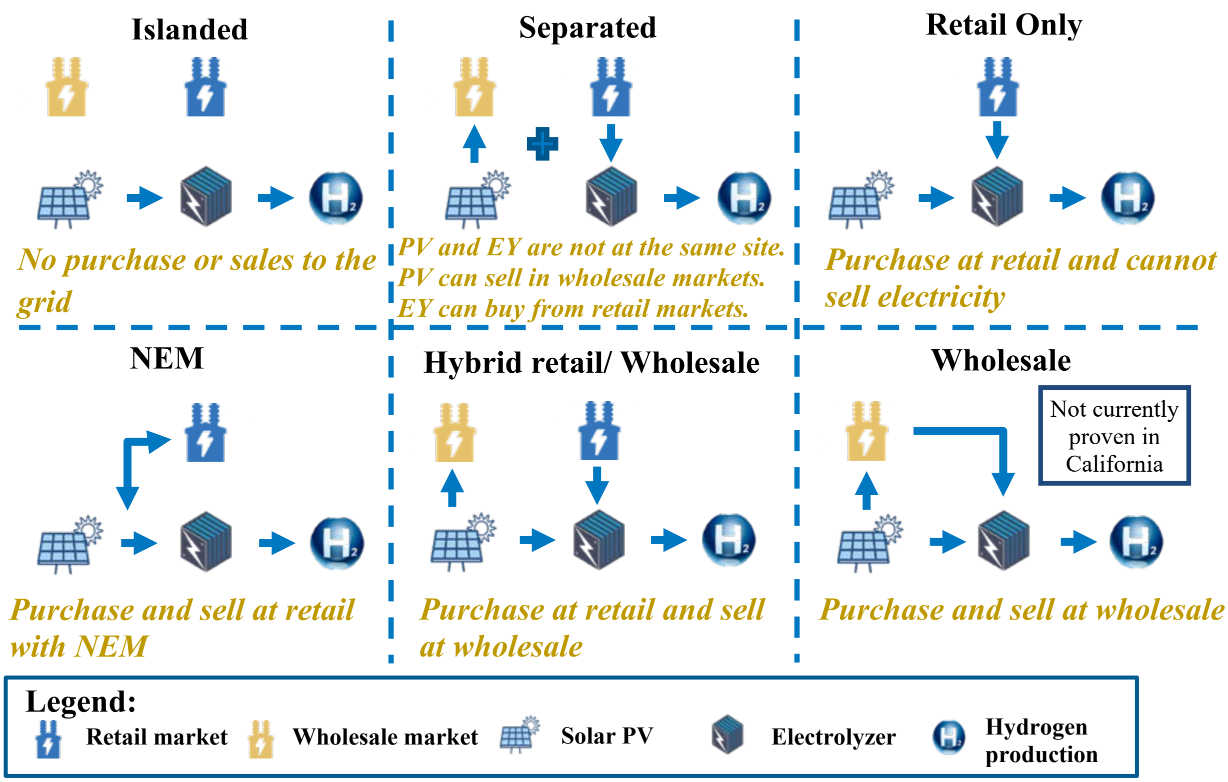

Figure 1. PV + Electrolysis market configurations

Islanded PV + EY

The first configuration is completely separated from the electric grid. All of the electricity required to produce hydrogen comes from on-site PV production. This means that the site does not pay for any electricity; however, can only produce hydrogen when electricity from PV is available. The electricity from the PV is produced only during daylight hours and all of it is used from the electrolyzer. The PV can also curtail but it cannot receive revenues from selling electricity to the grid. This configuration is particularly useful in isolated areas.

Pros: No electricity costs, 100% renewable

Cons: PV capacity factor limits hydrogen production

Separated PV + EY

This configuration represents a system where PV is installed at one location and the electrolyzer is installed at a separate location. PV sells to wholesale markets and the electrolyzer takes retail electricity service. To determine hydrogen production profitability, costs, and revenues from both, the PV and electrolyzer sites are combined.

Pros: Able to purchase electricity for the electrolyzer at any time of the day

Cons: Separated sites don't allow for synergy between installed equipment

Retail PV + EY

The PV and electrolyzer are at the same site. Electricity to produce hydrogen can come from the PV or from the grid. The electrolyzer is on a retail rate and the PV can send renewable power to the electrolyzer but cannot send electricity to the wholesale market.

Pros: Allows for integration between PV and electrolyzer.

Cons: The site is not able to sell during high electricity price hours

Retail PV + EY with Net Energy Metering (NEM)

Adding to the retail only configuration, this configuration adds the net metering rate allowing for the site to offset electricity costs or even get paid for selling electricity.

Pros: Enables higher value for excess PV generation than selling into wholesale markets.

Cons: Must meet eligibility requirements for PV[ii]

Hybrid Retail/Wholesale PV + EY

Building on the retail only configuration, this configuration includes the ability to sell PV electricity into wholesale markets during times of high electricity prices. This is particularly amenable for large PV systems that may not be eligible for retail rates.[iii]

Pros: Allows for integration between PV and electrolyzer, and also an opportunity to benefit from high price events in wholesale markets.

Cons: Requires resources to manage wholesale market operations.

Wholesale PV + EY

For this configuration, the combined PV and electrolysis system purchase[iv] and sell electricity at wholesale rates in every hour of the year. This is considered a limiting scenario since there are

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[ii] Facility electricity demand must be on the same order as the installed PV capacity.[12]

[iii] According to the NEM tariff sheet, renewable electrical generation facilities larger than 1 MW are subject to costs for any interconnection, and network and/or distribution upgrades according to Rule 21.[13]

[iv] For purchasing electricity an added cost for transmission and distribution is included in addition to the wholesale prices, while the sale of electricity only includes the wholesale prices.

only a few avenues by which demand response devices might be able to achieve this result. To access wholesale rates for demand response in California there is 1) CAISO programs[v] and 2) alternative methods of purchasing electricity directly from producers or acting as a load serving entity (LSE), electricity service provider (ESP), or similar entity.

1. The CAISO offers programs for market participation of demand response including the Non-Generating Resource (NGR) and Proxy Demand Resource (PDR) programs. NGR is focused on storage applications and therefore must also have the ability to generate electricity. PDR provides a bridge for demand response on retail rates to also get access to wholesale rates. But as described in footnote v, the net benefit test criteria is interpreted by the CAISO to only allow demand response to access wholesale rates for demand reduction beyond their typical operating profile (also known as baseline). While enabling participation, this effectively limits the value of demand response to participate in wholesale markets.
2. One of the most promising, yet unproven, techniques for accessing wholesale electricity for electrolyzers is to attain direct access to wholesale markets by engaging an LSE, ESP, or other similar entity. The electrolyzer facility can enter an agreement to purchase electricity at wholesale, or near wholesale rates, subject to any terms by the LSE, ESP, or similar entity.

While market rules continue to evolve to include the ability for distributed energy resources to participate in wholesale markets, presently, there are limited opportunities for participation and there may be constraints that come with that participation. Thus, for an electrolyzer to purchase electricity at wholesale prices in California in every hour of the year, as depicted in this study, it is not currently a proven option. As such, this is illustrative of a limiting but important potential market configuration.

Pros: Very low purchase price for electricity compared to retail rates even including the additional costs for transmission and distribution.

Cons: There are potential pathways, but none are currently proven for electrolysis in California markets.

2.2 Optimization Model

The Revenue Operation and Device Optimization Model (RODeO) is used to calculate the minimum breakeven cost for producing and compressing hydrogen given the market configurations explored in section 2.1. RODeO is written in the General Algebraic Modeling System (GAMS) and solves the mixed integer linear programming problem to determine the optimal operation for a given set of devices to minimize cost or maximize revenue. The RODeO

[v] In 2001, the Federal Energy Regulatory Commission (FERC) issued Order 745 which set out requirements that demand response resources operating in ISO/RTO areas be compensated at the market price (i.e., Locational Market Price) for services provided in energy markets, subject to a net benefits test. Order 745 was contested, but on January 25, 2016 the supreme court upheld the FERC's jurisdiction over regulating demand response as it relates to wholesale markets. The net benefits test was developed because of concerns that providing wholesale prices to demand response devices during all hours might not result in benefit to the customers. each ISO/RTO must interpret Order 745 to implement rules that comply.

model has been used to explore the cost competitiveness of a variety of technologies and configurations including PV+storage,[3] off-shore wind plus storage, wholesale market integration of electrolysis,[4] near-term business case assessment of power-to-gas in California,[5] California energy storage assessment,[6] electric vehicle smart charging, and long duration energy storage operation. Figure 2 illustrates the inputs and outputs of the RODeO model. Most notably, this model allows for both retail and wholesale market integration of storage and/or demand response devices in addition to including any number of renewable resources, additional facility load, and output products (e.g., hydrogen, methane, ammonia, methanol, etc.). One key assumption of this model is that the device being considered is not large enough to impact market signals. Given the size of the California electricity market (over 50,000MW) in comparison to the size of the devices modeled (20MW or less), this is a reasonable assumption.

For this project, the representation of project financing was improved. In addition to including credits and incentives, and equipment cost, a more detailed financing representation is introduced to include explicit representation of taxes, depreciation, and equity/debt ratio. Lastly, when calculating breakeven hydrogen price, the breakeven price itself affects operation decisions thereby creating a non-linearity. An iterative solution approach was introduced to ensure that the breakeven hydrogen price is properly optimized while allowing for a linear formulation.

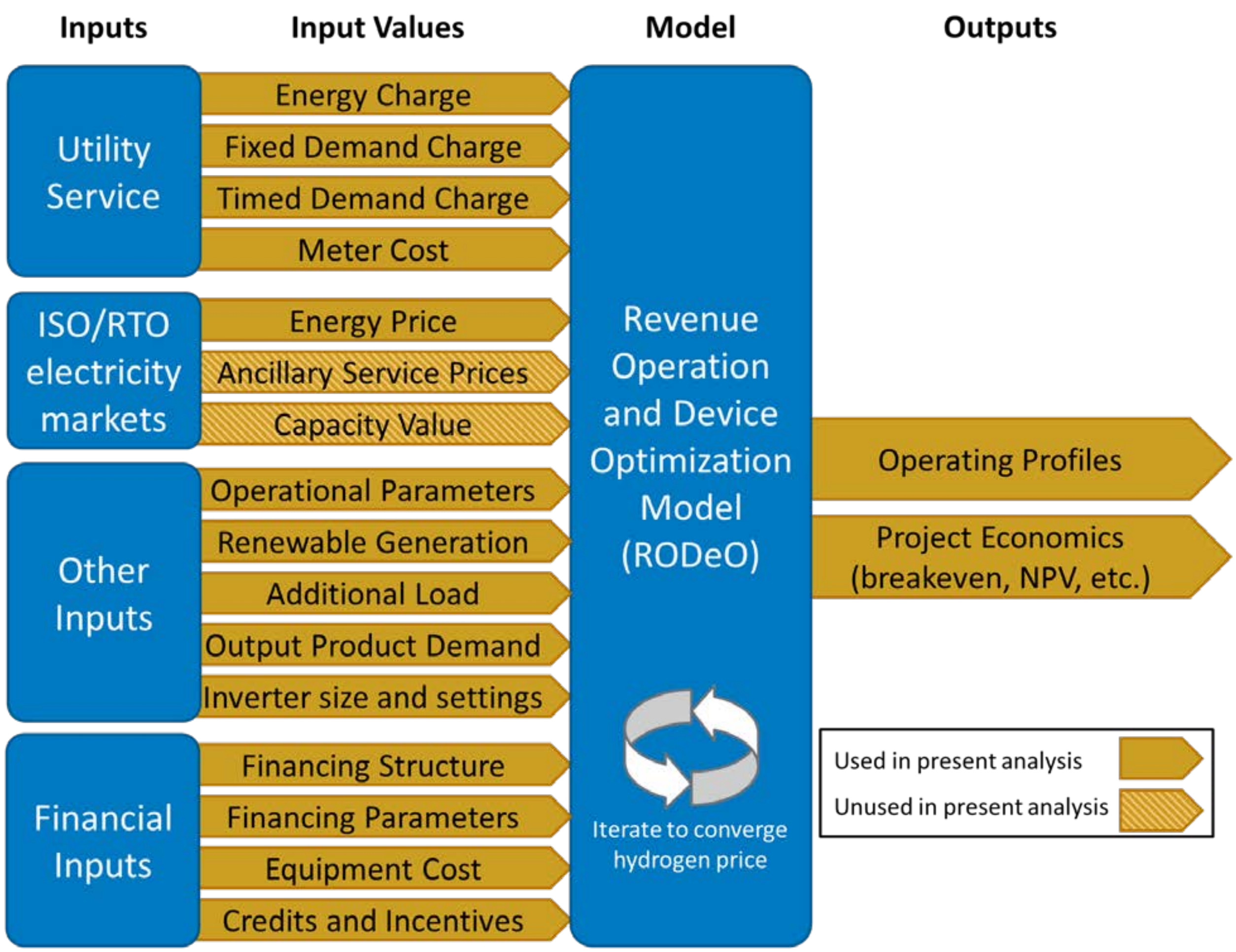

Figure 2. RODeO model flowchart

3 Candidate Locations for PV + Electrolysis

Six candidate locations are selected for examination. All sites are in Northern California. The information is drawn from schedule 3 of form EIA-860 and shown in Table 1. All of the sites utilize fixed tilt, crystalline silicon PV and have AC power capacities ranging from 2MW to 20MW.

Table 1. Technical Specifications for the Selected Solar Systems[14]

Name	DC Net Capacity (MW)	DC/AC Ratio	AC Net Capacity (MW)	Fixed Tilt Angle
Vaca-Dixon	2.6	1.30	2	30
Stroud	24.6	1.23	20	25
Five Points	17.6	1.17	15	25
Westside	18.5	1.23	15	25
Cantua	26.3	1.32	20	25
Huron	26.8	1.34	20	25

These sites were selected to understand the potential opportunity for adding electrolysis capacity to existing renewable generation sites. Currently all sites sell their electricity to wholesale markets, meaning that they all have the necessary equipment to participate in wholesale markets. The sites are shown graphically in Figure 3. The five largest sites are clustered in the Central Valley region of California.

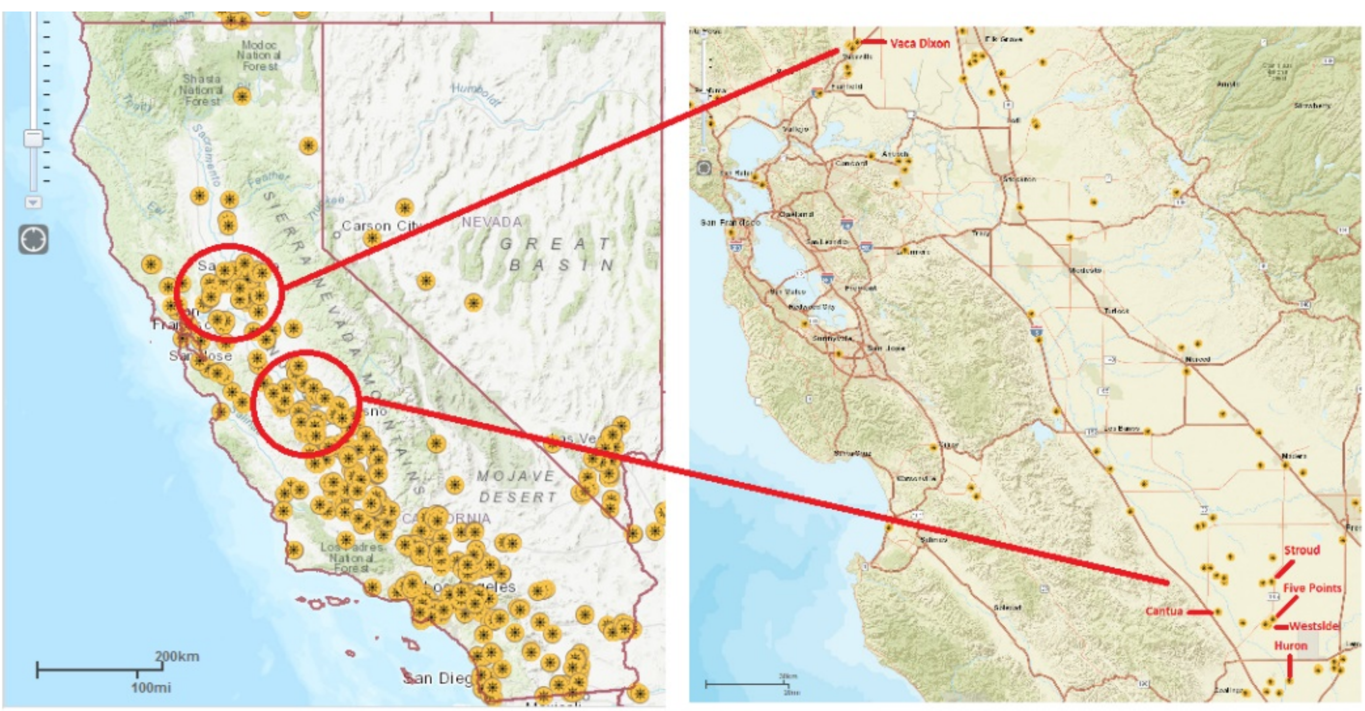

Figure 3. Location of selected solar power stations in California

4 Input Data and Assumptions

A variety of technical and economic data is required to perform the desired analysis. The sections below are separated into major categories including PV, Electrolyzer, electricity, cost parameters, financing, and credits and incentives.

4.1 PV Technical Properties

As discussed in section 3, six candidate sites are selected with power ranging from 2-20MW. Solar power production is determined at each site using the System Advisor Model (SAM).[15] SAM is a model developed by NREL that facilitates decision making by helping users make performance predictions and cost estimates for a variety of renewable power projects. SAM can automatically draw data from a variety of databases[vi] and takes other cost information, system design, financial information, electricity demand, and tax and incentive information. SAM can output a wide variety of results with regard to system planning and design, but for this project, we only use it to determine the power production at each of the six candidate sites. Coordinates for the locations used in SAM to calculate the solar power profiles are shown in Table 2.

Table 2. Location Data for Selected Solar Sites[14]

Solar Sites	AC Net Capacity (MW)	Coordinates
Vaca-Dixon, CA	2	38.4° N, 121.9° W
Stroud, CA	20	36.5° N, 120.1° W
Five Points, CA	15	36.7° N, 119.8° W
Westside, CA	15	36.4° N, 120.1° W
Cantua, CA	20	36.5° N, 120.4° W
Huron, CA	20	36.2° N, 120.2° W

The target year considered is 2016. It is important to use data that is chronologically the same to capture the appropriate relationship between, for example, PV power production and wholesale market prices. However, there is uncertainty associated with each input signal. As a result, power production data for each site was pulled for 18 years to understand the uncertainty in production. The average daily power profiles for each site are shown in Figure 4.

[vi] NREL Wind Integration Datasets, NREL Solar Prospector, NREL Biofuels Geothermal Resource, DSIRE (for U.S. incentives), and OpenEI Utility Rate Databases.

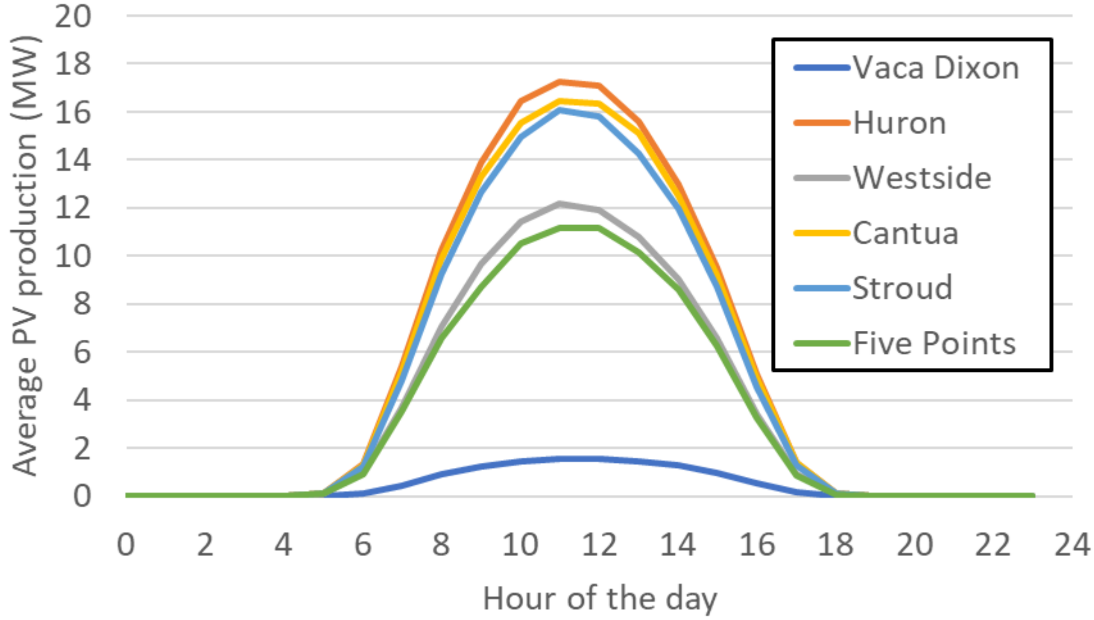

Figure 4. Average daily PV profile for each candidate site in 2016

While the shapes of the daily profiles are consistent from year to year, the total production experiences some variation over time. Expressed as an annual capacity factor, Figure 5 shows how the annual production varies. The maximum range of the capacity factor is around 4% showing that there is significant variability year to year. The relative rank of a given site does not change much over the course of 18 years (e.g., Westside always has the highest capacity factor, while Huron always has the lowest).

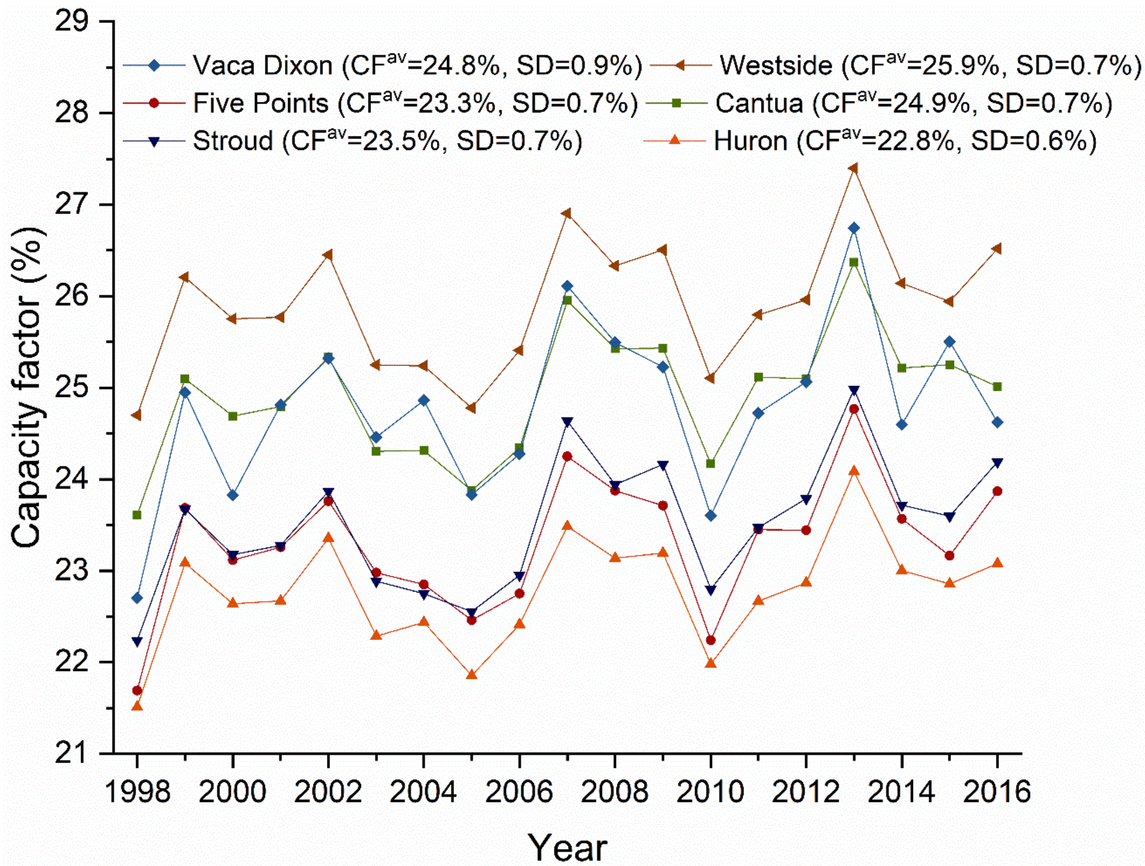

Figure 5. Annual capacity factors for candidate PV locations from 1998–2016.

CF^{av} = average capacity factor. SD = Standard deviation.

There are also variations in the monthly PV production which will affect the economics of PV + electrolysis systems. Figure 6 shows how the production varies for each month, for each site and year. These variations can be used to understand the level of uncertainty in the PV and correspondingly, the uncertainty in the calculated hydrogen prices.

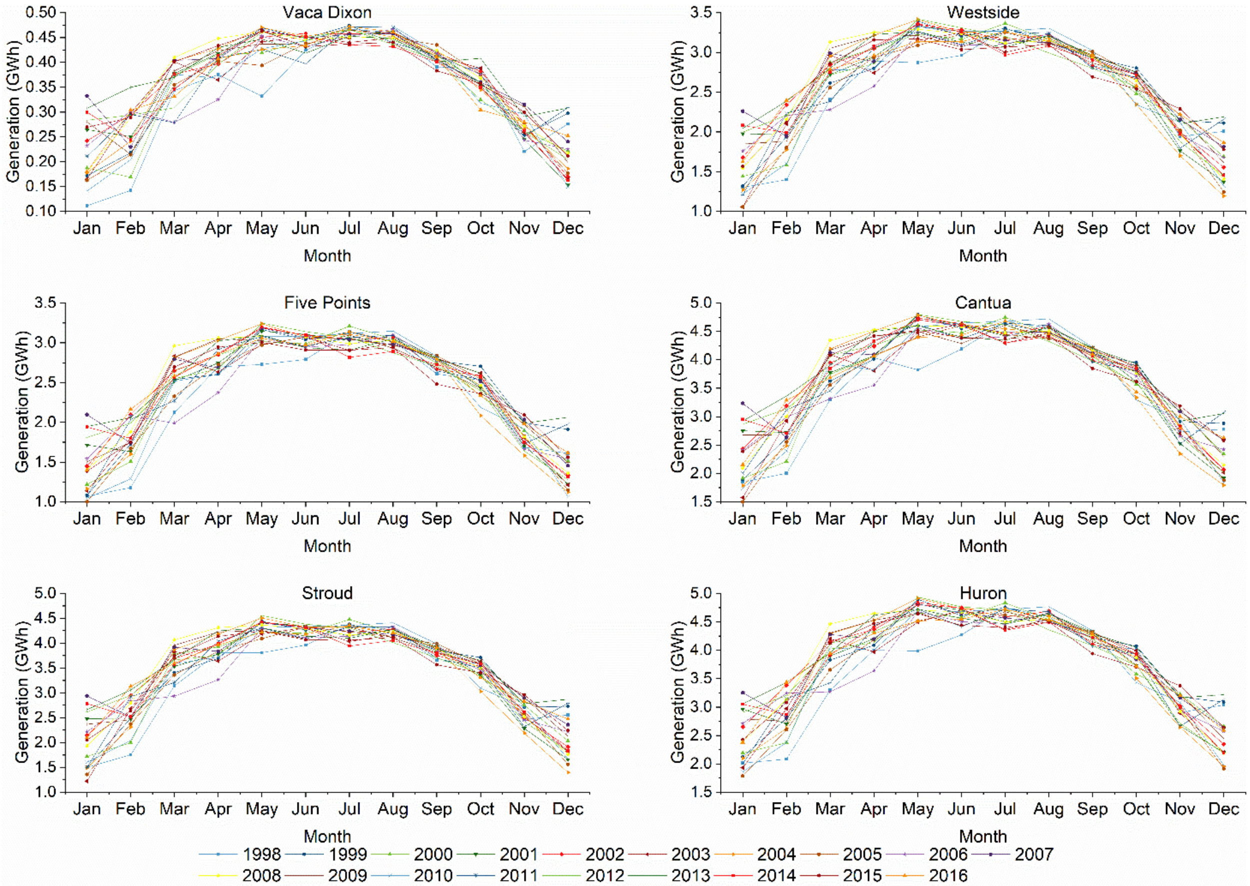

Figure 6. Monthly solar power production from 1998 - 2016 for selected locations in California

4.2 Electrolyzer and Compressor Technical Properties

The main technical properties include electrolyzer power capacity, electrolyzer operating properties, hydrogen storage capacity, and compressor properties. The electrolyzer capacity factor is optimized within RODeO to determine the ideal amount of hydrogen that should be produced to minimize hydrogen production cost. Hydrogen is assumed to be removed from the storage system at a constant rate each hour. For similar systems we have explored the potential of different strategies for removing hydrogen from the storage (e.g., daily constraint) and found that given the storage capacity on-site, it did not have a significant effect on the results.

Table 3. Technical Specifications for PV and Electrolyzer Systems

Property	Values
Electrolyzer capacity	0.02–200 MW[vii]
Electrolyzer efficiency	54.3 kWh/kg (61.4% on a lower heating value (LHV) basis)
Hydrogen storage size	8 hours of storage at rated electrolyzer power for all configurations except islanded (29.5 kg of storage LHV for 0.02MW and 29,500 kg of storage LHV for 200 MW) † ‡ 168 hours of storage for the islanded configuration
Compressor capacity	0.37–370 kg/hour (sized to max flowrate of electrolyzer) (20–950 bar)[16]
Compressor efficiency	1.1 kWh/kg

† The storage duration at maximum utilization capacity, i.e. if an electrolyzer is sized at 10 MW and the storage is sized at 8 h of rated electrolyzer capacity, the maximum storage capacity will be 80 MWh.

‡ 8 hours of storage was selected for all scenarios except islanded because it is sufficient to meet the needs for the system we have defined and increasing the size to 24 hours of storage unnecessarily increases the total cost.

The relationship between compressor's flowrate and cost illustrated in Figure 7 refers to high pressure two-stage compressors with output pressures varying from 20 to 950 bar.[16]

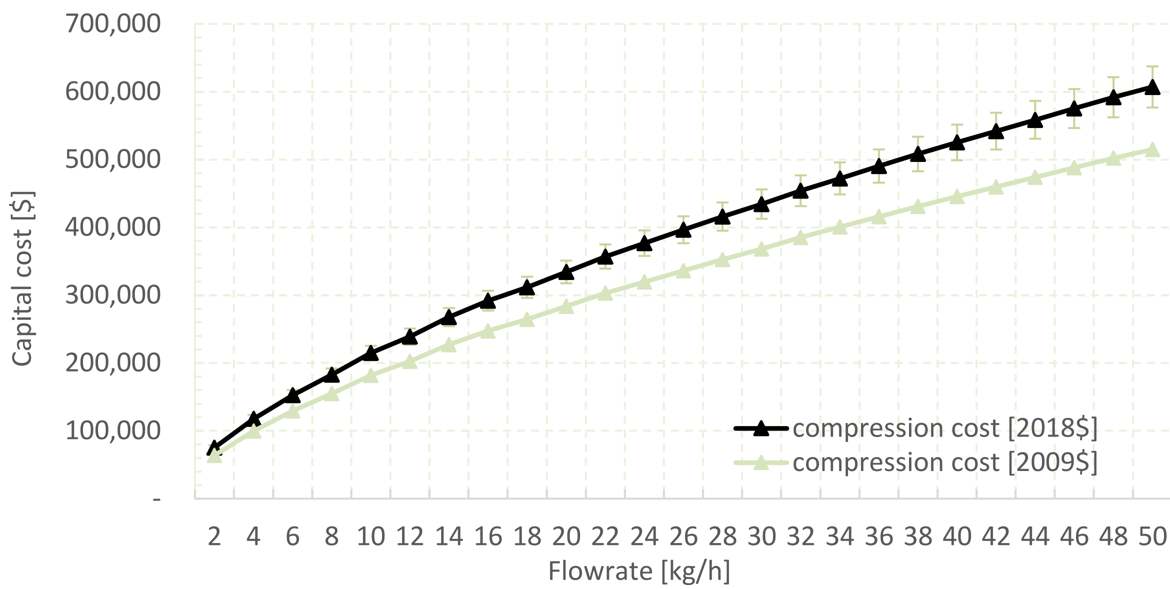

Figure 7. Compressor flowrate and cost (original 2009$ and updated to 2018$) relationship curve

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[vii] Electrolyzer sizes are modeled as discrete ratios of electrolyzer size with respect to PV size. The sizes considered include, 1%, 5%, 10%, 20%, 30%, 50%, 60%, 90%, 100%, 120%, 200%, 500% and 1000%. For example, 1% of 2MW PV at Vaca-Dixon is 0.02MW electrolyzer and 1000% of 20MW PV at Five Points is a 200MW electrolyzer.

4.3 Electricity Costs

In order to understand the differences between market configurations, retail and wholesale rate data is acquired for 2016. Table 4 contains a summary of the data used to model the rates. The NEM rate is complementary to the retail electricity rate (e.g., a customer will take service under the E-20 rate and then add the NEM on top of E-20).

Table 4. Summary of Retail and Wholesale Rate Properties

Property	Values
Retail	PG&E E-20: Service to customers with maximum demands of 1000 Kilowatts or more[13]
Net Energy Metering	Uses PG&E new California NEM tariff[12] Uses PG&E Net Surplus Compensation Rate (NSCR) for 2016[17] Uses non-bypassable charge of $19.19/MWh
Wholesale	2016 Nodal Locational Marginal Prices (LMP) considered for each site[18] Includes T&D costs for wholesale electricity purchase based on PG&E E-20: $47.22/MWh peak summer $17.94/MWh part-peak summer $3.55/MWh part-peak winter

4.3.1 Retail

Given the size of the PV considered at each site, the most reasonable utility rate to consider is PG&E's E-20 rate. This rate is a Time-of-Use rate with an energy charge, fixed demand charge, timed demand charge, and meter cost. All these elements are included to represent the complete rate. More details about the rate can be found on PG&E's website[13] or in the Utility Rate Database.

4.3.2 NEM

Net Energy Metering rates allow a unique opportunity to reduce electricity costs by offsetting electricity costs during times of consumption with excess generation at other times. California has a history of net metering legislation. This study focuses on the current California NEM, sometimes called NEM 2.0. Currently sites can apply for this NEM tariff if they meet the eligibility requirements. Eligibility for NEM 2.0 several requirements and exceptions must be determined on a site-by-site basis so we will only explore the overarching eligibility requirements. As will be shown, one of the most important requirements is that the load is the same size as the PV system. More information can be found in the NEM 2.0 tariff sheet.[12]

To be eligible for the NEM 2.0 rate, a customer must take service under a Time-of-use rate (e.g., E-20) and have an eligible renewable facility. Participation entitles customers to compensation for excess generation. Unlike previous versions of net metering tariffs, NEM 2.0 requires that excess electricity produced offsets electricity consumption in the same time-of-use bin. In addition, some excess production is subject to non-bypassable charge. Additionally, all renewable electrical generation facilities larger than 1 MW are subject to costs for any interconnection, and network and/or distribution upgrades according to Rule 21.[13]

The basic idea is that a customer can offset their electricity costs incurred during a given time-of-use bin with excess electricity produced in that bin and if the total monthly production exceeds the consumption, then the customer will receive compensation according to the Net Surplus Compensation Rate.

NEM 2.0 is fully implemented in RODeO and allows for the optimization of device operation with access to NEM 2.0 rates to minimize costs.

4.3.3 Wholesale

Wholesale electricity prices are collected for the six candidate sites. Prices from the generation node closest to each site are selected (Table 5). Prices data is gathered from ABB Velocity Suite. [18] As reminder, the ability for an electrolyzer to access wholesale rates for every hour of the year is still unproven and a potential strategy is outlined in this report in section 2.1.

Table 5. Summary of Generation Nodes Selected for Each Site

Plant Name	Generation Nodes
Vaca-Dixon	VACADIX_1_GN001
Stroud	STROUD_6_N003
Five Points	WSTFRSO_1_N017
Westside	SCHLNDLR_7_N002
Cantua	GIFFGEN_7_N002
Huron	WHDGAT2_7_B2

The prices and summary statistics for each site are presented in Figure 8. Notice that the seasonal price shapes are similar among all sites and that there are negative prices at every node. A summary of the maximum, minimum, and average for all sites is presented in Figure 9.

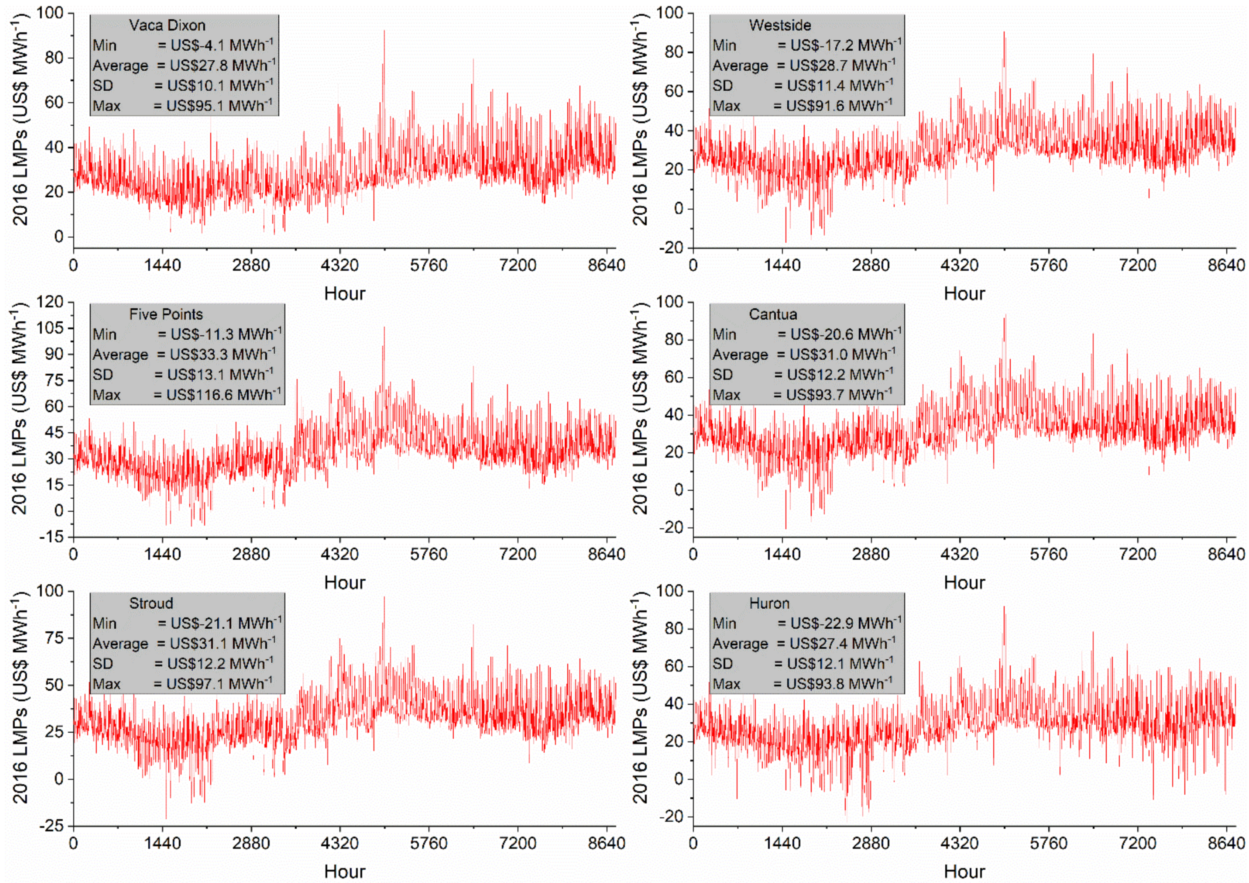


Figure 8. LMP for 2016 at the generation nodes closest to each candidate location.

LMP = Local Marginal Price, SD = standard deviation.

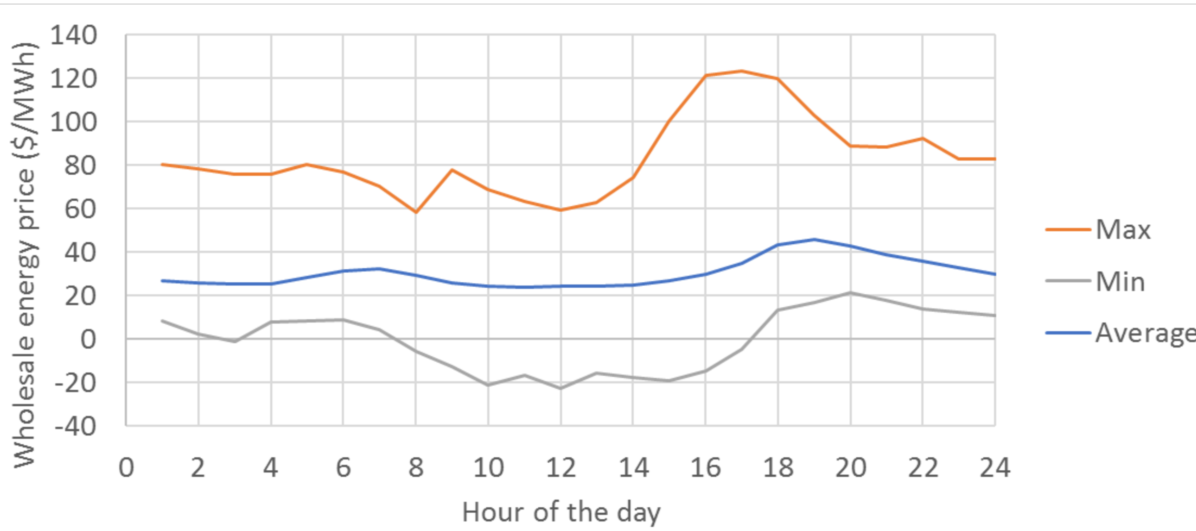


Figure 9. Average 2016 Wholesale LMP price range and average for all 6 solar sites[18]

For wholesale configurations, the system can sell electricity at the wholesale price, but a cost must be included when purchasing electricity to account for transmission and distribution costs associated with delivering the electricity to the site. We use the transmission and distribution components of the retail rate to account for this (Table 6). The total cost is the combination of the transmission charge and the distribution charge corresponding to the appropriate time-of-use bin.

Table 6. Transmission and Distribution Components from E-20 Rate

Property	Value [$/MWh]
Transmission charges	3.36
Distribution charges	
peak summer (midday to 6 pm)	43.86
part-peak summer (8:30 am to 12 noon, 6 pm to 12 midnight)	14.58
off-peak summer (12 midnight to 8:30 am)	0
part-peak winter (8:30 am to 12 midnight)	0.19
off-peak winter (12 midnight to 8:30 am)	0

4.4 Cost Parameters

Cost values are collected for each of the components modeled in the system. These values represent the current status for each component.

Table 7. Cost Parameters for Each Technology

Component	Values
Photovoltaic panels[7]	Capital: $1,746/kW (2017) Fixed O&M: $15.6/kW-year (2017) Lifetime: 20 years
Electrolyzer[8]	Capital: $1,691/kW (2017[viii]) Fixed O&M: $75.2/kW-year (2017) Replacement Cost: $18.6/kW-year (2017) Lifetime: 20 years
Storage[16]	Capital: $822/kg for medium pressure storage Lifetime: 20 years
Compressor[16]	Capital: The cost is based on the compressor flowrate as shown in Figure 7. Lifetime: 20 years

[viii] Inflated from 2007$ to 2017$

4.5 Financing Properties

A detailed representation of financing allows for better understanding of project economics and the impact of each property on the competitiveness of PV + Electrolysis systems. In addition, the impact on the project economics from a variety of different credits and incentives can be explored. Key financial properties considered are the federal and state tax rates, investment tax credit, asset depreciation, cost of capital, and debt/equity properties (Table 8).

Table 8. Assumptions for Financial Properties

Property	Values
Federal tax rate	21.0% (2019)
State tax rate	8.84% (California 2019)
Depreciation	5-year MACRS depreciation and first year bonus depreciation of 50%
Weighted Average Cost of Capital (WACC)	7%[ix]
Other properties	Rate of return: 4.89%[19] Return on equity: 10.25%[19] Debt interest rate: 4.81%[20] Debt period: 20 years Debt fraction: 58% (calculated from above properties) Equity fraction: 42% (calculated from above properties) U.S. Inflation: 1.9%

4.5.1 Depreciation

The optimization includes both Modified Accelerated Cost Recovery System (MACRS) depreciation and bonus depreciation. For MACRS depreciation, a 5-year depreciation schedule is used, consistent with PV panels. Bonus depreciation is taken in the first year and is assumed to be 50% of the capital investment.

Bonus depreciation is affected by the inclusion of the Investment Tax Credit (ITC). The basis for depreciation is affected based on the following equation: 1 – 0.5*ITC. This effectively reduces the bonus depreciation if the ITC is taken.

4.6 Credits and Incentives

Utilizing available credits and incentives offers an opportunity to increase revenues, reduce equipment costs, or reduce tax burden. A variety of credits and incentives are explored for PV + Electrolysis systems including the Low Carbon Fuel Standard (LCFS), Renewable Energy

[ix] WACC = Debt fraction * (1 – Debt interest rate) * Rate of return + Equity fraction * Rate of equity

Credits (RECs), ITC, and state tax credits. A summary of the assumptions for these credits and incentives is presented in Table 9.

Table 9. Summary of Assumptions for Credit and Incentives

Credits and Incentives	Values
Low Carbon Fuel Standard (LCFS)	Assuming $180/credit
Renewable Energy Credits (RECs)	$12/MWh for renewable energy sold in wholesale markets
Investment tax credit (ITC)	Assuming 0% (default)
State tax credit reductions	Several tax reductions are considered (see below)

4.6.1 Low Carbon Fuel Standard

California offers the LCFS which provides an incentive for reducing transportation emissions below the benchmark for either gasoline or diesel fuel. Figure 10 shows the average, and range of LCFS credit prices along with trade volumes over the course of the program.

The LCFS program provides an incentive for carbon reductions volumetrically (i.e., based on the amount of emissions reduced per ton) and for capacity of fueling stations (i.e., based on the capacity to serve vehicles). The capacity credit helps incentivize early market fueling station development and is paid to the fueling station. Given that this report examines hydrogen fuel production and not delivery and dispensing, only the volumetric credit is considered.

The preferred LCFS carbon reduction pathway discussed in this report is to offset light-duty vehicle emissions by replacing gasoline with hydrogen in a hydrogen fuel cell vehicle (FCEV). The FCEV pathway has been shown to be one of the more valuable pathways for hydrogen.[5]

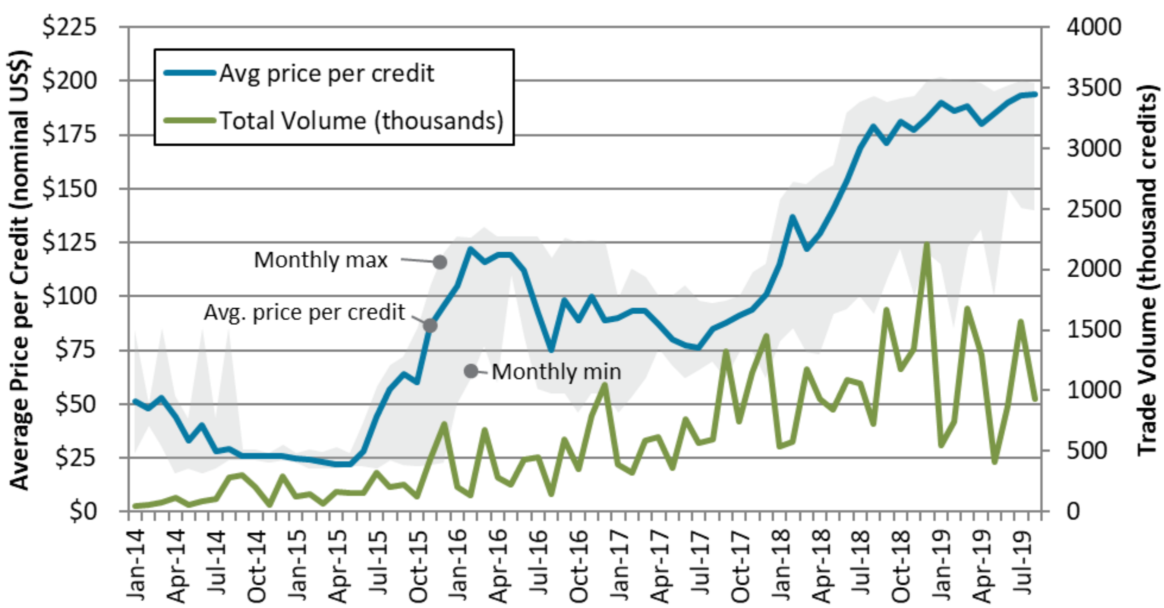
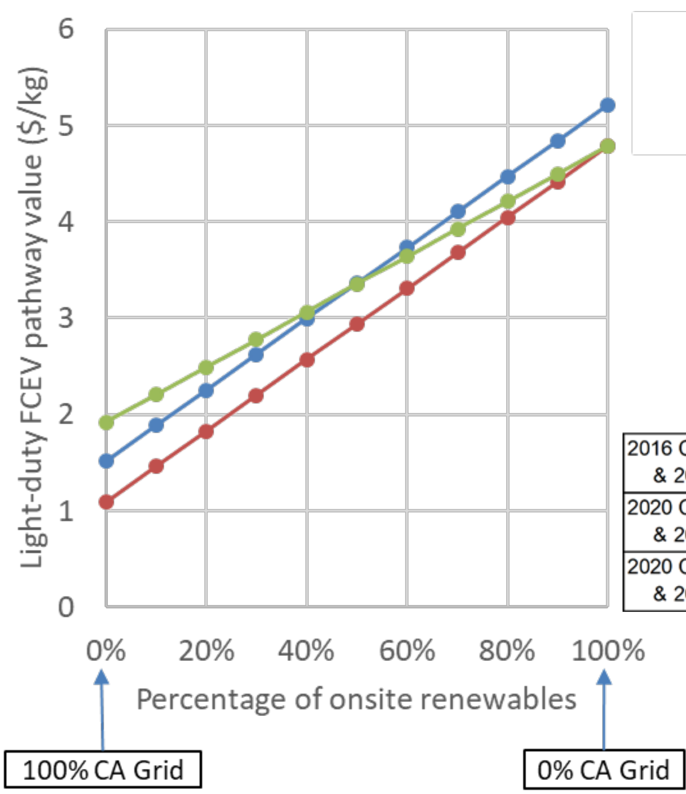


Figure 10. LCFS historical price and volume curves[21]

Drawing electricity from the California grid to produce hydrogen in an electrolyzer will reduce the carbon intensity of gasoline light-duty vehicles. Adding electricity from the PV will further reduce the carbon emissions and increase the credit payment (Figure 11).[22,23] However, there are several properties to consider when determining the appropriate LCFS value. Key parameters are listed for three example calculations of a FCEV pathway in Figure 11. The blue line represents the values assumed for this report. The red line shows similar a grid mixture but shows the impact of vehicle fuel economy compliance in 2020, when the vehicle fleet has become more efficient, reducing the benefit of converting to FCEVs by $0.42/kg. Lastly, the green line represents 2020 vehicle compliance and the grid mixture in the 2017 grid. The grid carbon intensity changes from 96.5 gCO2e/MJ in an earlier year to 88.6 gCO2e/MJ in 2017. While 2020 vehicle compliance still reduces the LCFS value for FCEV pathways, the lower grid carbon intensity increases the benefit of using California grid. Understanding how these values change with different assumptions allows for characterization of sensitivity to those assumptions and more complete applicability of this analysis across potential sites and years.



	Electrolyzer efficiency [kWh/kg]	Energy density of hydrogen [MJ/kg]	Energy Economy Ratio (EER)	Grid carbon intensity [gCO2e/MJ]	Baseline carbon intensity [gCO2e/MJ]	LCFS credit price [$/credit]
2016 Compliance & 2010 Grid	54.3	120	2.5	105	96.5	180
2020 Compliance & 2010 Grid	54.3	120	2.5	105	88.6	180
2020 Compliance & 2017 Grid	54.3	120	2.5	81.5	88.6	180

Figure 11. LCFS value for FCEV fueling from electrolysis pathway given three sets of assumptions

4.6.2 Renewable Energy Credits

In order to support renewable portfolio standard compliance, a system of tradeable Renewable Energy Credits (RECs) has been implemented in California. If renewable generators meet the requirements, they can produce RECs, which can be traded to facilitate RPS compliance and provide an additional revenue stream to the producer.

In-state PV power production has access to California's bundled REC category (i.e., category 1).[24] Access to REC prices for California are not publicly available, so we rely on an estimate of $12/MWh for RECSs in category 1.

4.6.3 Investment Tax Credit (ITC)

The Investment tax credit is a vehicle to reduce tax burden based on the capital investment in certain technologies. The ITC can be claimed for up to 5 years after installation, and if you do not have enough tax burden in the first year, it can be applied over the 5-year period.[25,26] Presently, solar PV is eligible for the ITC and there are examples of other technologies receiving the ITC including solar water heating, fuel cells, geothermal, combined heat and power, and batteries.

To be eligible, storage must be charged greater than 75% of the time, annually, from a connected renewable resource. For storage that charges between 75% and 100% from renewables, the storage will receive that same fraction of the credit. This includes either a new battery installed with a new system, or a new battery added onto a pre-existing system.[27]

It is currently up for debate if non-battery storage is eligible for ITC, and companies have signed a letter to Congress asking them to clarify, acknowledging this would be helpful for the industry.[28] There have been multiple private cases where it has been approved[29] but there was ambiguous language that makes it seem like it should apply to any general storage device that is used solely for storage (i.e., you cannot use it to heat a recreational pool, and then claim that the pool is a storage device for heat energy[30]) The ITC is applied to the entire system, including interconnection wires and the software to control charging and discharging. There have also been bills trying to clarify how widely the ITC applies, one in 2016,[31] and one in 2017,[32] but they have not come to a vote. Federal Energy Regulatory Commission (FERC) has recognized the unique nature of energy storage and its many uses in the grid.[33]

The ITC for PV reduces over time from 30% to 10% as depicted in Figure 12. The systems must be operational in the year in which they receive the credit.

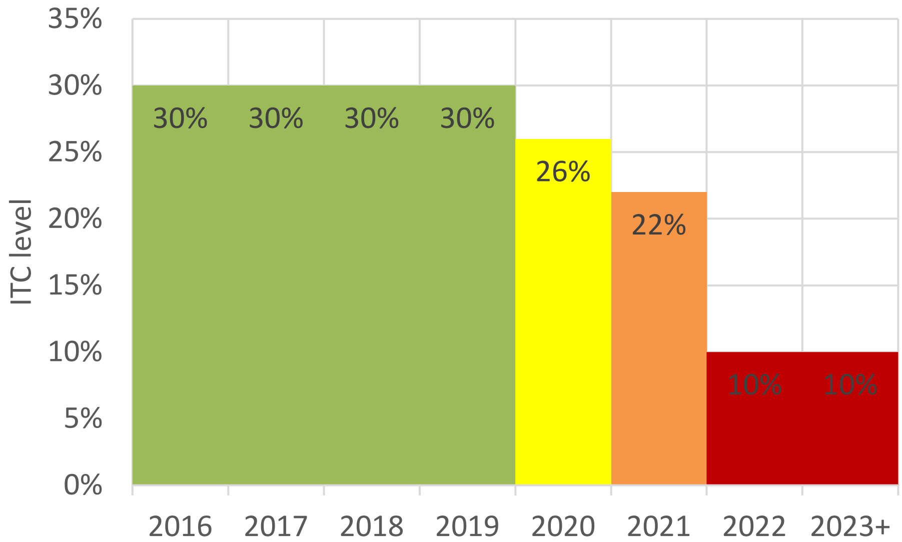


Figure 12. Level of ITC for PV

4.6.4 State Tax Credits

Working with California Governor's Office of Business and Economic Development (GO-Biz) we have identified several state tax credits for which a PV + Electrolysis system would be potentially eligible. Table 10 contains a list of these credits along with a short description. It is important to note that this list is by no means complete but represents a list of the items that, the authors thought, are particularly relevant for the system considered.

Several incentives require specific criteria to be met. For example, the California research credit requires participation in research activities, and the competes tax credit is for businesses that want to come to California or stay and grow.

The manufacturing, and research and development (R&D) equipment exemption, and the sales and use tax exclusion programs have fewer requirements and there is a good chance that PV + Electrolysis systems are eligible since the systems are in the alternative energy and storage space. The manufacturing and R&D provide a 3.9375% state tax reduction for qualifying property and the sales and use tax exclusion program would waive state sales and use taxes on eligible property.

For this report, the default state tax value does not include any of the following reductions. The impact of introducing state tax reductions is introduced in the sensitivity section (section 5.4).

Table 10. Potential State Tax Credits, Exemptions, and Exclusions for PV + Electrolysis Systems

Incentive	Description
California Research Credit	• Available to taxpayers engaged in qualified research activities in California • 15% of the excess of the qualified research expenses, over the base amount, plus 24% of the basic research payments
Manufacturing and R&D Equipment Exemption	• Be engaged in a qualified business (i.e., engaged in the generation and production, or storage and distribution of electric power) • The partial exemption rate is currently 3.9375 percent. The partial exemption provides that sales of the qualifying property sold to a qualified person be taxed at a rate of 3.3125 percent (7.25 percent current statewide tax rate – 3.9375 percent partial exemption) plus any applicable district taxes.
Sales and Use Tax Exclusion (STE) Program	• Eligible manufacturers planning to construct a new manufacturing facility or expand or upgrade a currently existing manufacturing facility may apply to the California Alternative Energy and Advanced Transportation Financing Authority ("CAEATFA") Sales and Use Tax Exclusion ("STE") Program (the "Program"), and if approved, the purchases of Qualified Property for the project are not subject to state and local sales and use tax • Qualifying if property is used to manufacture Alternative Source products or Advanced Transportation Technologies. • Maximum $20 million of STE per project in a calendar year • Until 31st Dec 2020
California Competes Tax Credit	• Available to businesses that want to come to California or stay and grow in California • Negotiated incentive: The applicant shall set forth its requested California competes tax credit amount in the application form. The minimum amount of such request shall be twenty thousand dollars ($20,000) and the maximum amount shall be subject to the limitations set forth in Revenue and Taxation Code sections 17059.2 and 23689.

5 PV + EY Results

Using the methodology laid out in section 2 and the locations and inputs values laid out in sections 3 and 4, we will answer several important questions about hydrogen system configuration, sizing, operation, and preferred locations.

Each of the six configurations is optimized and the breakeven production cost (including production and pressurization in preparation for gaseous delivery trucks) is determined. The results for Vaca-Dixon are presented in Figure 13. Each row contains a description of the configuration, a breakdown of each cost component, and sizing and operation information to the right. Values to the left of zero represent revenues, and values to the right represent costs. The total value is denoted by the black line. The cost component breakdown is similar for each site (see Appendix A). The total values are summarized in Figure 14.

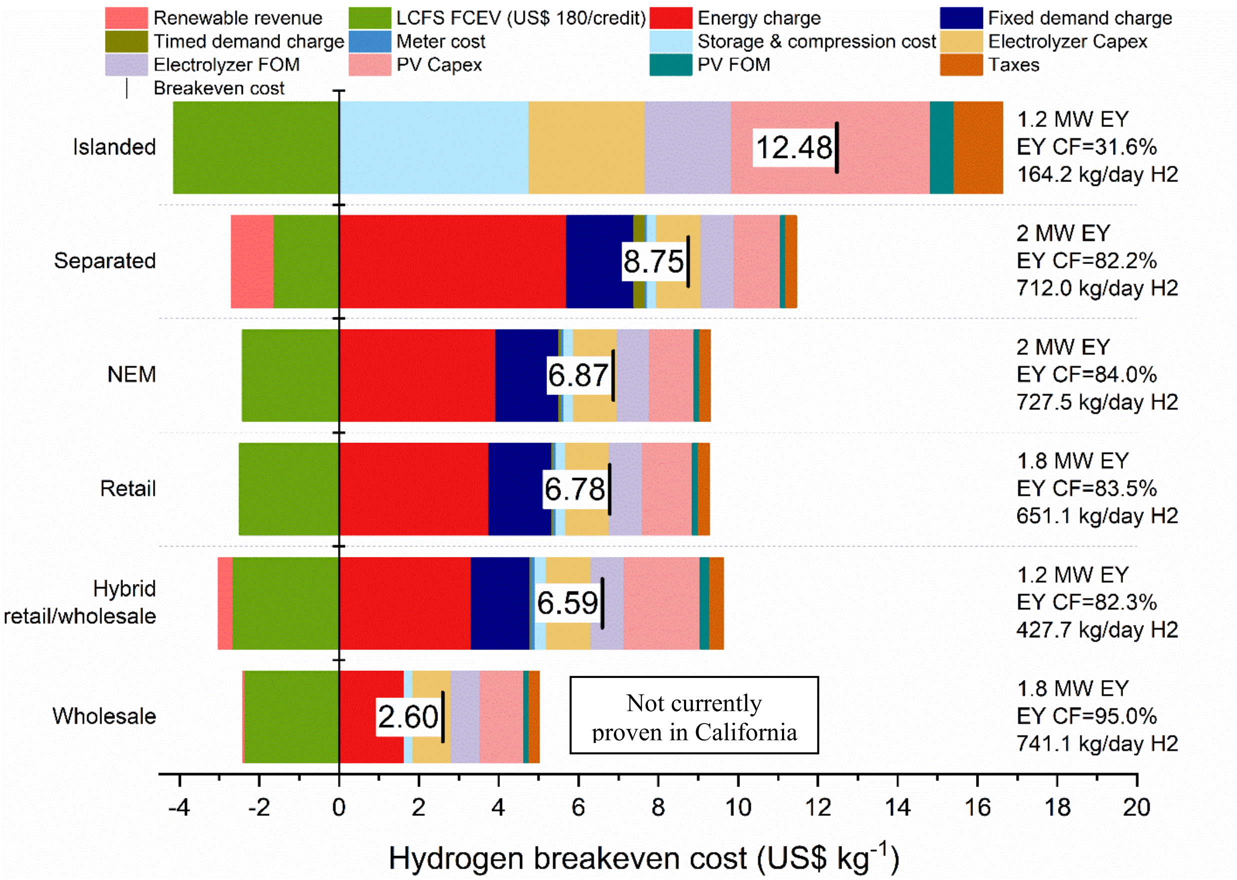


Figure 13. Comparison of current breakeven hydrogen production cost for Vaca-Dixon with 2 MW of PV

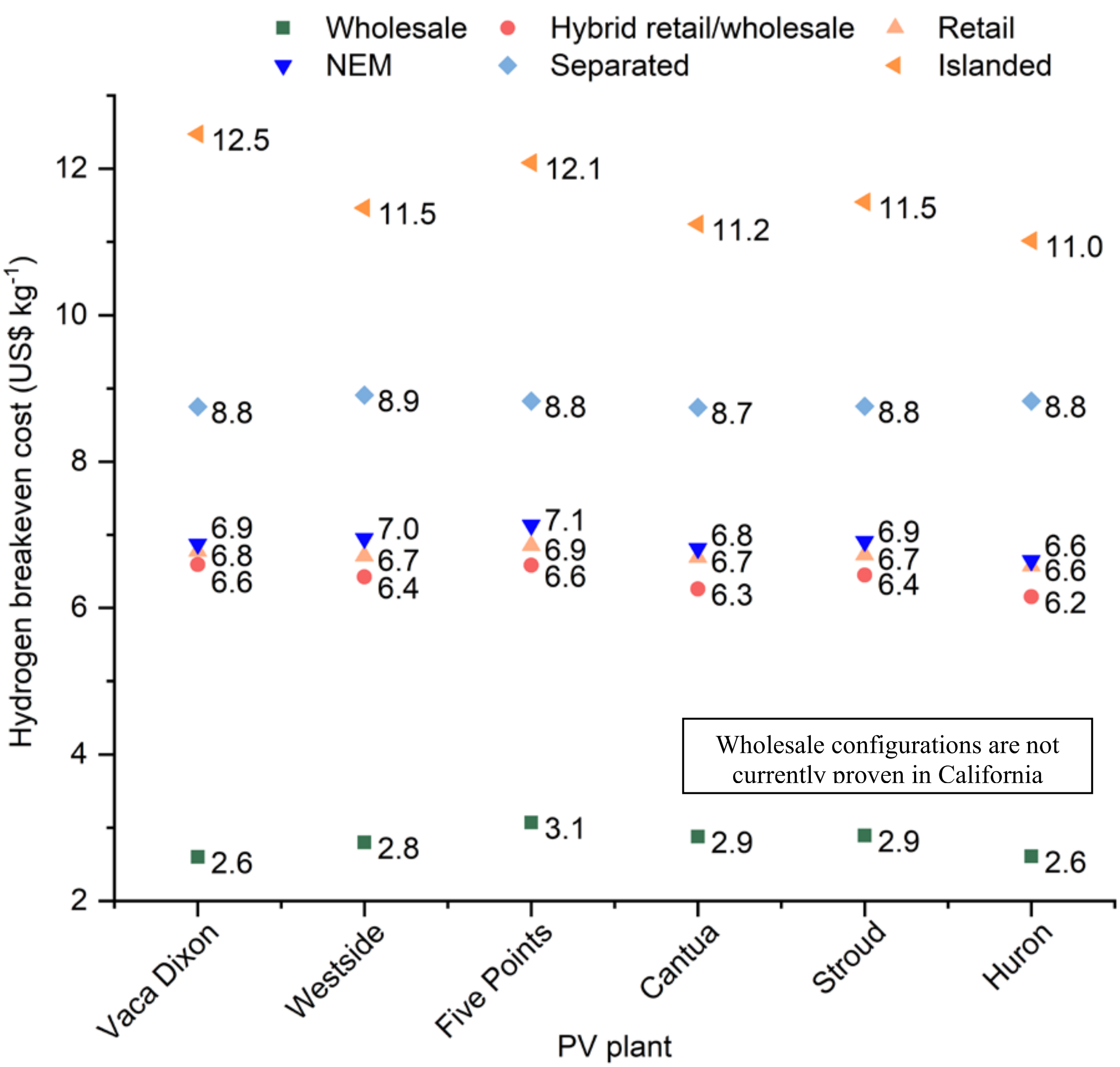


Figure 14. Comparison of current total breakeven hydrogen production costs across all locations

5.1 Discussion

The rank of each configuration is the same for all locations: 1. Wholesale (lowest cost), 2) Hybrid retail/wholesale, 3) Retail only, 4) NEM, 5) separated, and 6) islanded (highest cost). The following subsections describe the results in more detail.

Islanded: No purchase or sales to the grid

While the islanded system does not pay for electricity the capacity factor is limited by the solar creating a situation where the capital investment for the electrolyzer and storage is underutilized resulting in higher costs. Since the hydrogen is 100% renewable, the LCFS is the highest of all configurations.

Results show that the ideal electrolyzer to PV ratio is 60% (i.e. 2 MW PV system and 1.2 MW electrolyzer) and the storage duration should be around 1 week or 168 hours at rated power. On the surface it would seem like if you have a 1:1 ratio you could use all the renewable electricity;

however, the optimization shows that while increasing the electrolyzer size increases hydrogen production and thereby reduces the PV capital cost components, the electrolyzer cost increases and reduced utilization of the electrolyzer far outweighs the other changes. Since the capacity factor for Vaca-Dixon PV is 24.3%, using a 2 MW electrolyzer results in a 24.3% capacity factor for the electrolyzer while using a 1.2 MW electrolyzer results in a 31.6% capacity factor for the electrolyzer. Interestingly for the storage duration, a week of storage adds to the cost, but it reduces curtailment by allowing for some seasonal shift of hydrogen produced in the high PV summer season to the other seasons. The cost breakdown for different durations is shown in Figure 15. As the storage duration increases, the cost of the storage in comparison to the overall system cost increases but the benefits of reduced curtailment and increased hydrogen production cause each of the other cost components to reduce. Around 168 hours, increasing storage does not produce enough benefit to outweigh the added storage cost and the total breakeven cost goes back up.

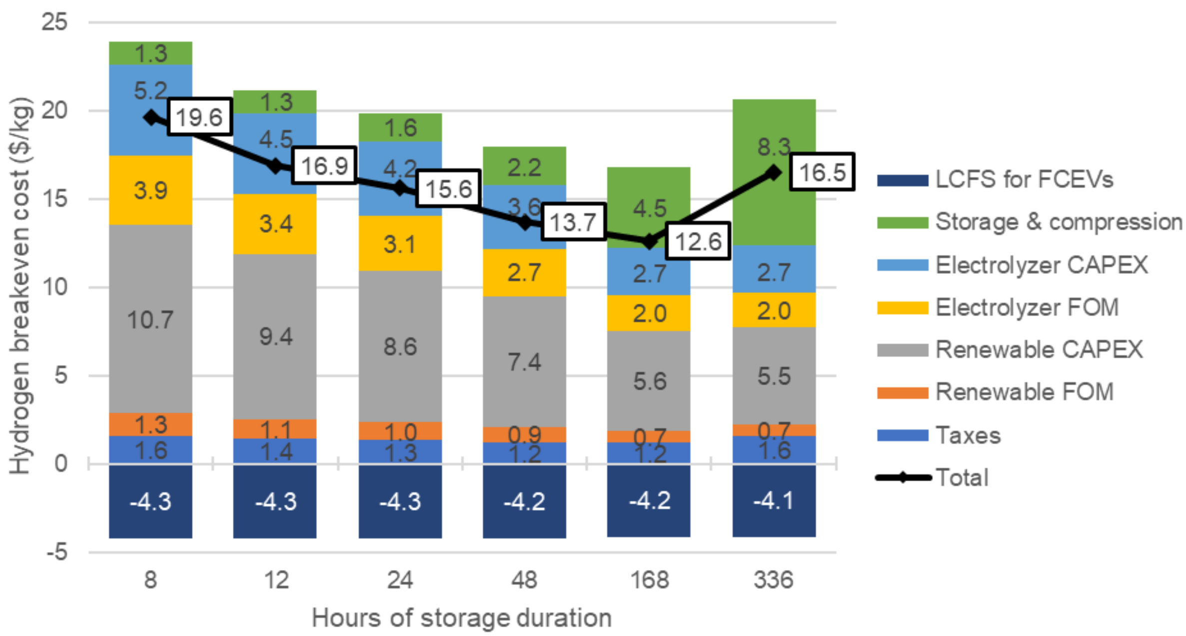


Figure 15. Hydrogen breakeven production cost breakdown for different storage durations with a 1 MW EY and 2 MW PV at Vaca-Dixon

There may be several exceptions where islanded systems could make sense. For instance, if the capacity factor can be increased with a combination of wind and solar, that might make the system more competitive. Also, in the event that the grid interconnection costs are very high there is an opportunity to reduce overall hydrogen production cost by installing an islanded system.

Separated: PV and EY are not at the same site

The Separated PV + EY configuration is used as a reference to understand the costs for implementing each technology separately. PV can only sell to the wholesale market and the electrolyzer can only purchase at retail rates. While this represents a significant reduction in hydrogen breakeven production cost compared to the islanded system, it is at least $2/kg more expensive than the integrated, grid connected systems.

Moving from islanded systems, the electricity cost becomes a significant portion of the costs (i.e., 68% of the cost components); however, because of the much higher utilization at 82.2%, the capital cost contribution to the system costs falls dramatically representing just over 30% compared to 93% for the islanded scenario.

Renewable electricity sales represent a modest revenue when compared with total system costs. This is because the PV must sell into wholesale markets. PV is often sold to customers using a power purchase agreement (PPA). Based on the price and conditions set in the PPA the equipment owner can help to offset low wholesale prices and also mitigate market volatility; however, these agreements are often proprietary, so instead we examine a conservative case where the PV is fully exposed to wholesale prices.

As demonstrated in Figure 11, using 100% California electricity grid still produces a positive LCFS value. While the LCFS value is smaller than other scenarios with higher renewable penetration, it still represents a significant revenue stream for hydrogen electrolysis systems.

NEM: Purchase at retail and sell according to NEM

To the authors' knowledge, this is the first time an optimization has been done to represent reduction potential with NEM 2.0. The NEM 1.0 lumped all excess generation that occurred during a month into the same bin, but the NEM 2.0 added the stipulation that excess generation only counted in the same time-of-use bin in which it was generated. This means that you cannot shift PV generation in the afternoon to the night. Ideally, NEM allows the participant to use excess renewables to reduce electricity costs at the same level as the retail rate, while the wholesale participant can only reduce electricity costs at the much lower wholesale market price. This structure is particularly valuable for inflexible loads that occur in the same time-of-use bin; however, for fully flexible loads that can already shift to the same time as the PV, it does not provide additional benefit.

For NEM 2.0, the PV installed capacity must be sized to the load and cannot be larger than the maximum load. Vaca-Dixon with 2 MW of PV must install a 2 MW electrolyzer. Because the renewable electrons are the lower cost and the electrolyzer has enough capacity to use all renewable electrons, there are never any times that excess generation is available. The NEM configuration has a higher breakeven production cost than the retail only scenario, which chooses a slightly smaller electrolyzer at 1.8 MW. The added 200 kW of electrolyzer is underutilized and causes the breakeven cost to increase.

As NEM rates evolve, the rules for compensation and eligibility may reduce benefit and even prevent participation for certain systems. Just as the transition from NEM 1.0 to NEM 2.0 added additional complexity, the next NEM rate may have similar changes that will affect the value of participation.

Retail only: Purchase at retail and cannot sell electricity

The retail only configuration represents an integrated, grid connected system without electricity export. Transitioning from the separated system, integration of PV and electrolysis reduces the cost by around $2/kg. While electrolyzer size and capacity factor experience only a modest change, the biggest cost items to change are the renewable revenue and the electricity cost, which is a combination of the energy charge, fixed demand charge, timed demand charge and meter cost. A standalone PV system only has access to wholesale market prices and RECs, which are notably lower than the cost that the electrolyzer pays for retail electricity. Thus, integrating PV with electrolyzers allows for significantly lower cost electricity at the expense of a reduction in renewable revenue. In addition, the use of on-site renewables increases the renewable content of the hydrogen thereby increasing the LCFS value, which nearly accounts for the reduction in renewable revenue alone.

Hybrid retail/wholesale: Purchase at retail and sell at wholesale

Participation in wholesale grid markets comes with a variety of requirements. Some of these requirements include metering to keep track of transactions, grid interconnection study to understand any additional infrastructure needs, and scheduling coordinator to handle bidding. Since the PG&E locations with PV considered for this study are already prepared to participate in wholesale markets, no infrastructure or operational changes are necessary.

Enabling the sale of renewable electricity allows the system to take advantage of high-priced hours to sell electricity while also reducing the electricity cost and increasing the LCFS payment by utilizing renewable power into the electrolyzer.

Since this configuration only adds capabilities beyond what is available in the retail only configuration, the cost for Hybrid retail/wholesale must always be less than or equal to that of the retail only system. In the worst case, the hybrid system would behave the same way as that of the retail only system resulting in the same cost. However, the breakeven cost reduces between $0.2/kg and $0.4/kg across all locations, demonstrating that there is value in further integration with wholesale markets.

Wholesale: Purchase and sell at wholesale

The first thing to note is that while programs exist in California to allow for wholesale market access, none have been proven for the PV + Electrolysis application. A detailed description of options for wholesale market participation is provided in section 2.1. For this method, the sale of electricity is exactly the wholesale price while the purchase of electricity is the wholesale price plus an additional cost for transmission and distribution shown in Table 6.

As modeled, the electrolyzer has perfect foresight into wholesale prices, so the resulting breakeven hydrogen cost represents a minimum and in a real-world environment, will be greater due to errors in forecasting. However, when we look at the daily operation of the electrolyzer with wholesale prices, it is quite consistent, operating all day except during the peak hours (6-7PM) of most days, so even a simple operating schedule that avoids the forecasted peak load hours, would achieve the majority of the cost reduction potential.

Driven by lower electricity cost, the resulting production cost for hydrogen using wholesale prices is significantly lower than the other retail or hybrid scenarios. As a comparison, the average price for electricity used to produce hydrogen is shown in Figure 16. The separated system represents purchase of electricity at the full retail rate, while the retail, NEM, and hybrid scenarios include electricity from PV to offset the average electricity price. Even including the cost reductions and payments for NEM, electricity costs for the wholesale scenario are still significantly lower.

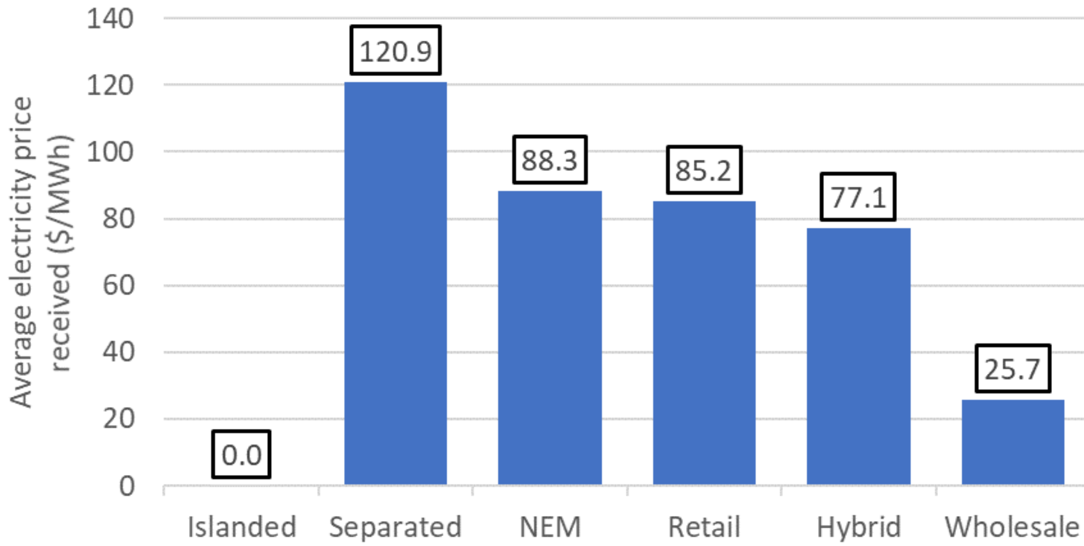


Figure 16. Comparison of average electricity price received at Vaca-Dixon for each scenario

Building on that point, an important metric for all scenarios is the ratio of electricity costs to total system costs (Figure 17). Note that total system costs do not include additional revenue streams from LCFS or RECs. Excluding islanded, electricity costs make up between 33% and 76% of the costs. The addition of PV already reduces the fraction by around 15% (i.e., separated compared to retail and NEM).

This information can help to determine the extent to which an electrolyzer is willing to accept a more "aggressive" rate structure (i.e., higher prices during peak periods or other techniques to more strongly encourage load shaping) to reduce electricity costs. In this case, most costs for the wholesale configuration come from the capital components, meaning that further electricity cost reductions are less likely to reduce the total cost than capital cost reductions. Conversely, the separated scenario has a relatively high fraction of costs from electricity so this system would benefit from more aggressive rates structures that allow for a flexible load to further lower the electricity cost with rate optimization.

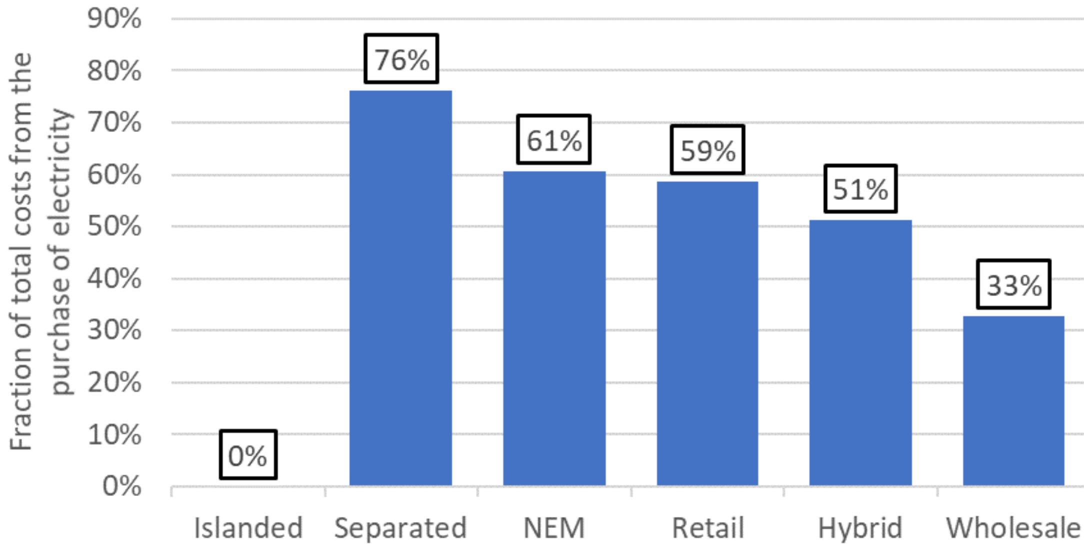


Figure 17. Comparison of electricity costs to total system costs at Vaca-Dixon for each scenario

5.2 Electrolyzer Operation Profiles

Understanding the operation profiles for electrolyzers provides insights into the factors driving the economics of the system as well as gives installers and operators some indication of the potential operating profiles. Using the optimal scenarios shown in Figure 13, the average Summer day operating profile[x] for the electrolyzers is shown in Figure 18 and the average Winter day is shown in Figure 19.

For the islanded system, the electrolyzer operates only when the solar is available; hence, the electrolyzer power profile resembles the solar profile.

The operation profile for the separated system is determined exclusively by the tariff structure since there is not PV on-site. The resulting electrolyzer profile has a large step in the Summer to avoid high energy and demand charges. Because the tariff structure has a constant demand charge in the Winter and the difference in the energy charge for the time-of-use periods is small, the electrolyzer operates close to the same level all Winter.

NEM, Retail, and Hybrid have roughly the same shape for both Summer and Winter with a few exceptions in the Summer. Lastly, the operation for the wholesale configuration reduces in the evening to avoid high wholesale prices that develop just as the solar production falls off.

[x] The average includes 184 days for each hour of the Summer profile and 181 days for each hour of the Winter profile.

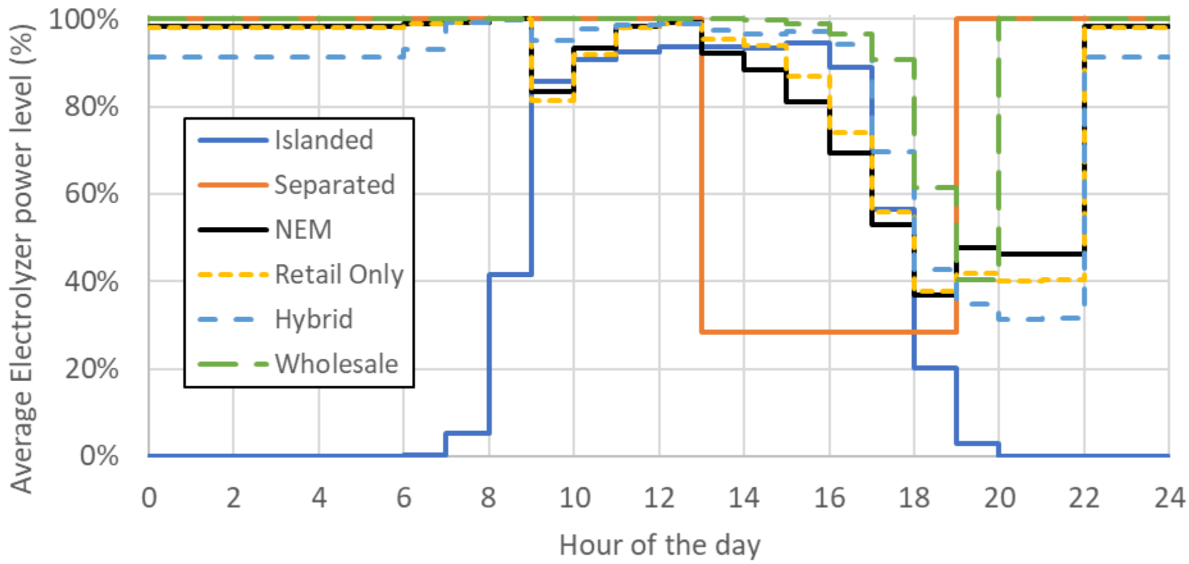


Figure 18. Average daily electrolyzer operation profiles at Vaca-Dixon for utility rate period A (Summer)

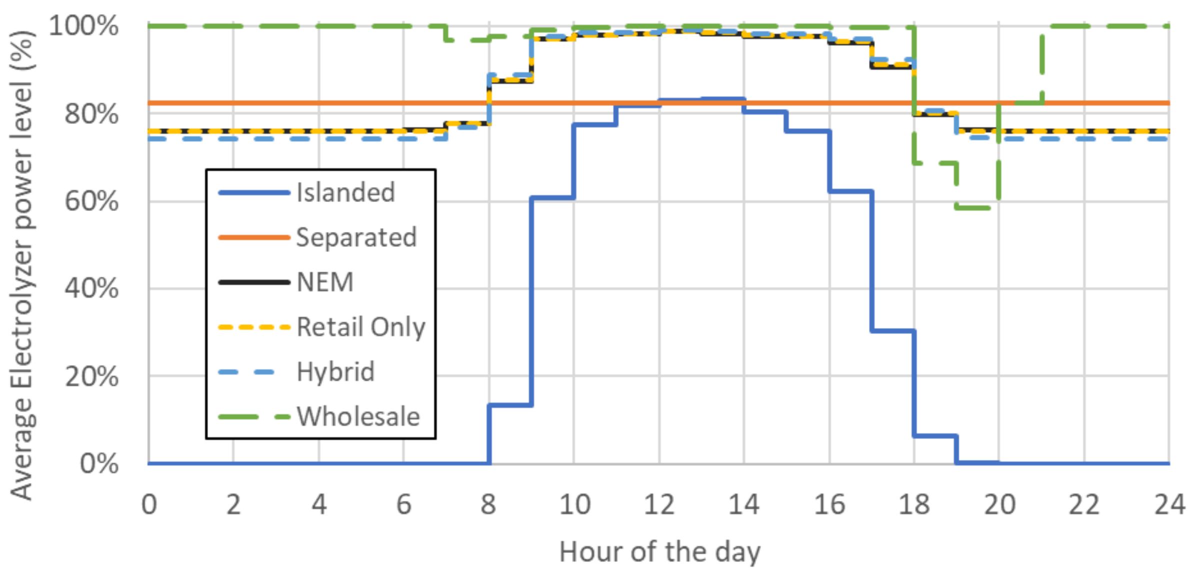


Figure 19. Average daily electrolyzer operation profiles at Vaca-Dixon for utility rate period B (Winter)

5.3 Renewable Hydrogen and Curtailment

Integration with renewables creates a variety of trade-offs for system sizing and operation. The system must make decisions about whether to sell PV generation, to generate RECs or use it to produce renewable hydrogen and LCFS credits. The objective of the optimization is to minimize the total system cost. That means that renewable hydrogen production will be increased only if it will lower the cost. Figure 20 shows the hydrogen renewable fraction from two perspectives. The first is considering only the onsite PV and the second considers all renewable electrons from both the PV and the California grid (using 2016 data). The results show that, of the lowest cost options (i.e., NEM, retail, hybrid, and wholesale), hybrid results in the highest hydrogen renewable fraction followed by retail, NEM, and finally wholesale.

This indicates that achieving a renewable fraction of between 47% and 60% is not only feasible but is also the economic choice when considering co-locating with PV. Additionally, from a policy point of view, this could mean that encouraging production facilities to produce some fraction of renewable hydrogen in California (e.g., 50%) would not negatively impact the project economics and could result in improvements. While the values shown here are specific to PV, wind power is likely to result in a similar finding only with different values.

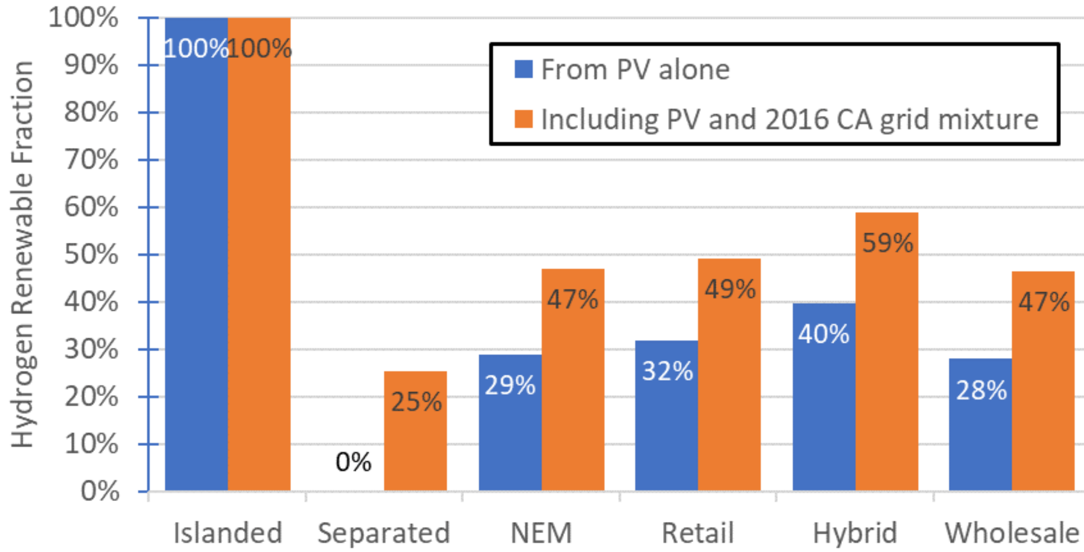


Figure 20. Hydrogen renewable content considering either the PV production or the PV production and California 2016 grid mixture for each configuration

As the renewable penetration on a power system increases, the potential for excess generation resulting in curtailment increases. That is particularly true for PV which has a production profile that is coincident with similar renewable technologies.

Integration with electrolysis allows for PV to find another market for the power produced. From the perspective of the electrolyzer, PV production represents lower cost electricity than can be purchased from the grid, so the system will consume as much as is possible. This holds true for all scenarios; however, there are instances where installing a greater amount of PV and allowing some curtailment is the lowest cost option. This economic curtailment is demonstrated in Figure 21.

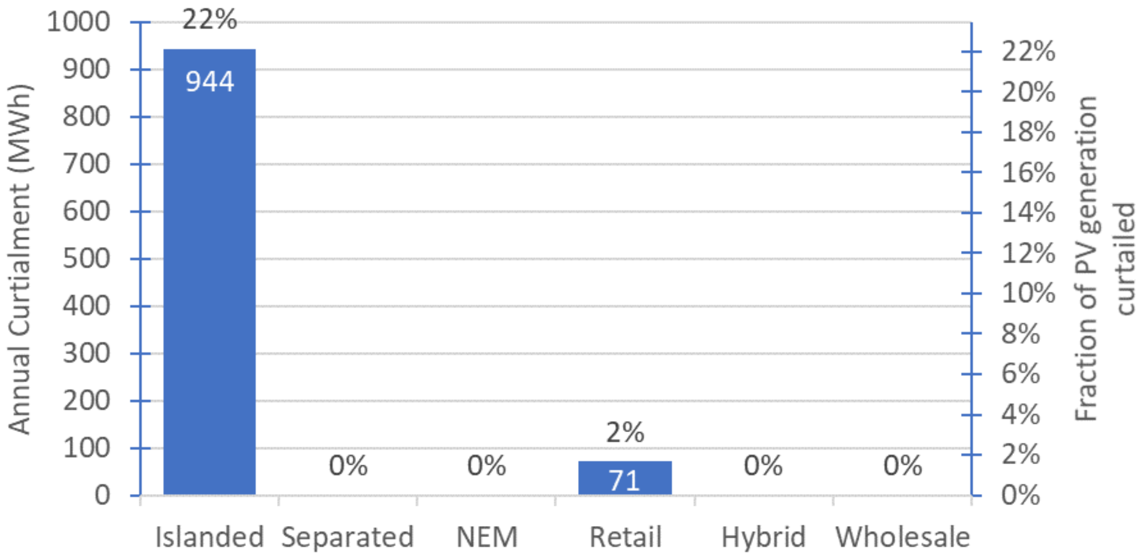


Figure 21. Comparison of curtailment and fraction of PV curtailed for each configuration

The optimal electrolyzer capacity for the isolated system is around 60% of the PV capacity. As a result, the electrolyzer can take advantage of additional renewable power but must curtail the excess. An example is shown in Figure 22. If the electrolyzer is equally sized with the PV (e.g., 1.2 MW), then the electrolyzer could use all the renewable generation and produce 31% renewable hydrogen. However, if 2 MW of PV is installed then the electrolyzer can use 8% more renewable electricity but must curtail 25% of the potential PV generation. This example uses the same optimal equipment sizes as the isolated system at the Vaca-Dixon location. In this case, the added cost of the PV is more than offset by the increased utilization of the hydrogen equipment.

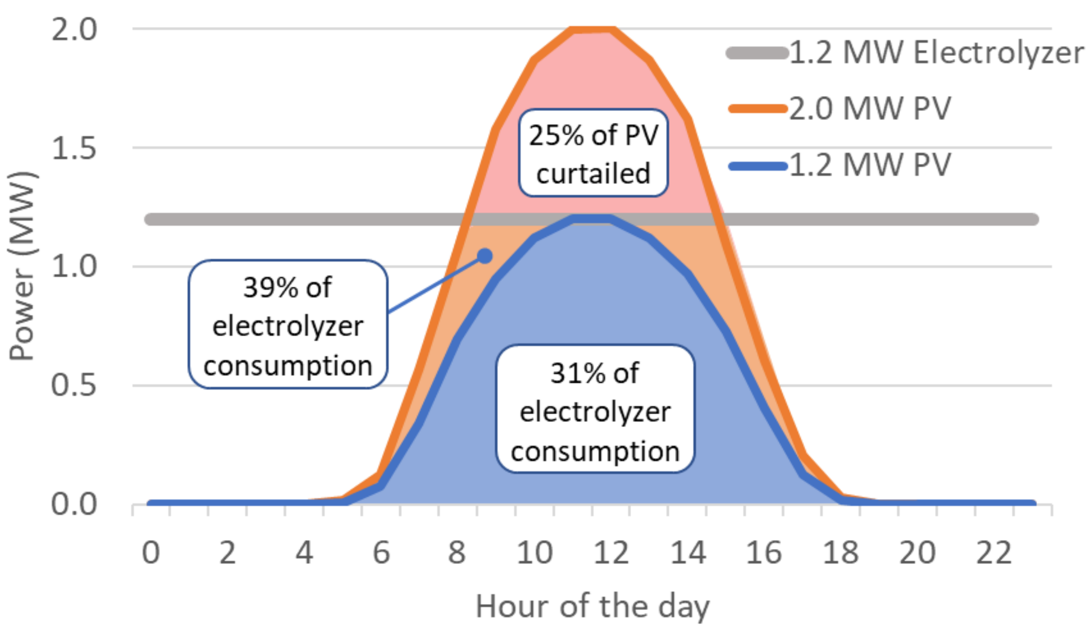


Figure 22. Example demonstrating how oversizing PV can impact electrolyzer plant operation

5.4 Additional Sensitivity Analyses

A collection of sensitivities is run to understand the impact of variations on the cost of hydrogen production. Varied parameters include the electrolyzer cost reductions, ITC value, upfront project equity percentage, solar resource, and taxes. The results are shown in Figure 23. The base value is $6.59/kg, from the hybrid retail/wholesale configuration. The biggest factors affecting the hydrogen breakeven cost are electrolyzer cost reductions, solar profile, and ITC while financing and tax properties have a smaller impact. Combining the cost reductions, ITC, and equity and tax rate adjustments results in a total cost of $4.16/kg for the hybrid scenario. It is important to note that combining sensitivity elements is not additive. Rather, the system must be re-optimized including all the desired elements, as was done here.

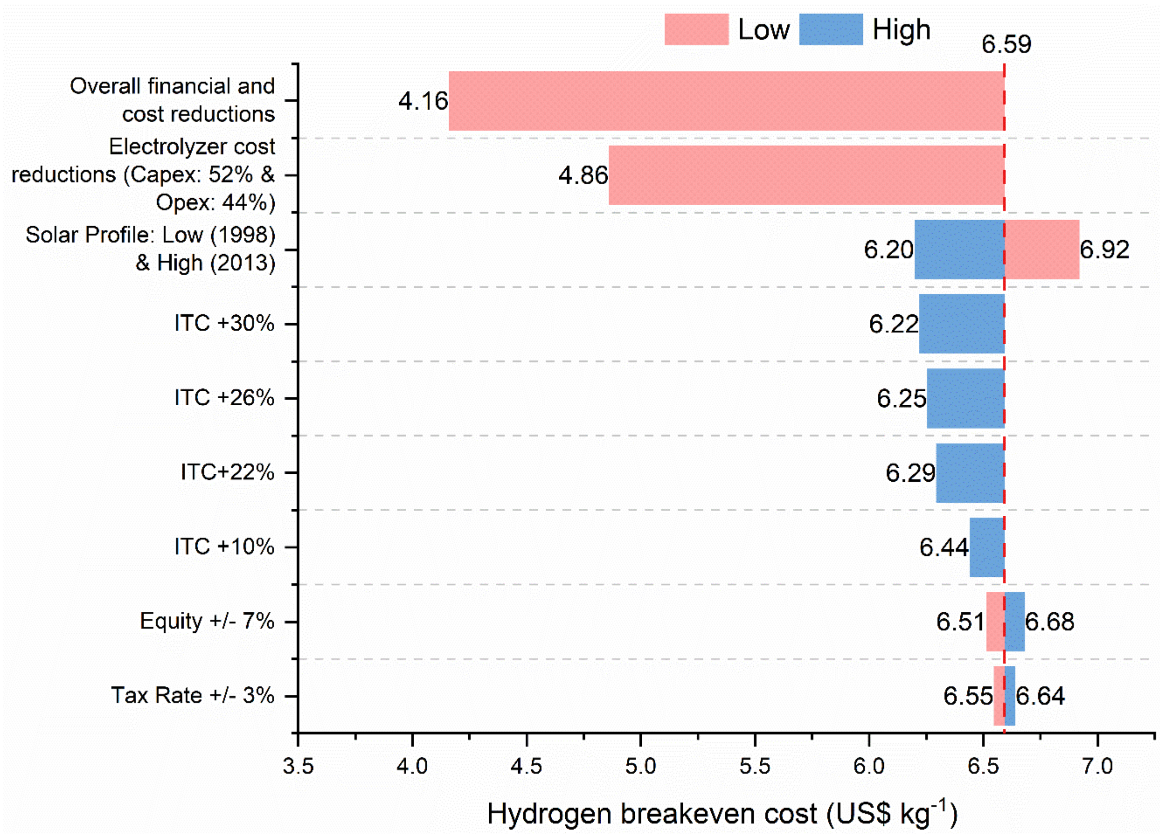


Figure 23. Tornado chart examining sensitivities to hydrogen production price for the Vaca-Dixon hybrid system configuration

From the items that were considered, the largest impact by far is from reducing the electrolyzer cost. The default cost values are from the H2A v3.101 current forecourt electrolyzer case study and the future values are from the future forecourt electrolyzer case study.[8] Following the H2A assumptions with inflation for current and future systems, the capital cost is reduced from $1,691/kW to a future cost of $812/kW, a reduction of 52%. Similarly, the yearly operational costs are reduced from $93.9/kW-year to $53/kW-year, a reduction of 44% including both fixed operation and maintenance, and annual equipment replacement costs.

A high solar production year can reduce the costs by $0.39/kg while a low production year can increase the costs by $0.33/kg. Since 2016 is close to an average solar year, the expectation is that during the lifetime of the equipment there will be some years with greater and some with lower production. Yearly uncertainty in solar production should be considered when preparing a cash flow analysis.

The default value chosen for the ITC was 0%, signifying that neither the PV nor the electrolyzer receive the ITC. Given the timing for project development and construction, it is unlikely that a project could be built fast enough to receive the 30% ITC; however, future years still have significant potential to reduce the system cost and in turn, the hydrogen production cost. Even once the ITC has reduced to its lowest level (i.e., 10%), the production cost can be reduced by $0.15/kg or 2.3%.

The sensitivity on tax rate and equity to debt has a smaller impact compared to the others but it is still very important from a project planning and investment perspective to select the set of properties that yields the lowest cost.

5.5 Value Streams Considered and Not Considered

This study characterizes a variety of value streams for electrolyzer integration with the grid and co-located with PV. A list of the most notable value streams considered include:

- Sale of hydrogen
- Sale of LCFS credits
- Sale of renewable electricity to the grid
- Sale of RECs
- Electricity cost reduction through retail or wholesale rate optimization

In addition to the revenue streams listed above, there are a number that were not characterized in this study. The following list contains those non-characterized items, and discussion about potential value.

- **Hedging against wholesale market price variability for PV**

  With increasing amounts of PV on the power system, most having very similar production profiles, each additional unit of PV provides diminishing benefit to the system and reduced revenue to the owner. This can already be seen in the price curves in section 4.3.3. Figure 9 shows the occurrence of negative prices during the afternoon hours when PV is generating. Combining with an electrolyzer enables the PV to sell to the electrolyzer during periods of low or negative market price to make renewable hydrogen, which is more valuable than taking the market price at that time.

  As the target for renewable penetration in California increases and more solar is installed to meet it, the trend of low afternoon prices is likely to continue to grow. Co-location with an electrolyzer allows PV producers to hedge against current and future market price volatility. Just like wholesale prices, this value is highly location specific and without knowledge of future prices, it is difficult to predict the potential value of hedging against price volatility.

- **Transmission deferral or avoidance**

  Many of the large central renewable installations in California do not occur at the load center and require transmission to move the power to the point-of-use. Just as discussed in section 5.3, there is a level of economic curtailment when installing transmission lines to move renewable power. For instance, if a 100 MW PV farm is built, there may only be a few hours a year that 100 MW is produced, so it makes sense to install a smaller transmission line that will lower system costs at the expense of some economic curtailment.

  Electrolysis could be added to the renewable site before transmission lines are installed. This, combined with the cost for transporting hydrogen, would change the economics of equipment and transmission sizing and have the potential to reduce the combined cost.

- **Integration with non-flexible loads**

  Performing rate optimization with a fully flexible load can significantly reduce the average cost of purchasing electricity when compared to a non-flexible load. When combined with a non-flexible load, the flexible load can also provide some reduction to the average electricity price.

  Most buildings or facilities are considered non-flexible loads (e.g., office buildings, warehouses, retail shops). While they may have a small amount of loads that can be operated flexible, the majority of load is non-flexible. Those facilities must be close enough to the PV and electrolysis system to combine their electrical loads. On account of the wide variation in load shape and concern about access to nearby loads at the PV locations, the addition of non-flexible loads was not included in this analysis.

- **Capacity credit value for PV**

  Depending on the coincidence of the PV production with electricity demand, PV plants can increase revenues by producing generation capacity credits.[34] As the PV penetration on the power system increases, it has been shown that the capacity credit decreases rapidly.[3]

  While integration with electrolysis will not increase this credit, it is possible that it could be operated in such a way as to not reduce the credit. The electrolyzer could be operated to maintain PV production during the times when it generates the most capacity credit value. This would also create a trade-off between the capacity credit value and the opportunity cost of producing hydrogen or providing other services. It is possible that there is complementarity between the capacity credit and high electricity prices, which are already encouraging the electrolyzer to operate to maximize PV capacity credit value.

5.6 Considerations for Site Selection

This report performs extensive analysis on six specific renewable sites in California. Finding the appropriate location for a production facility requires balancing several different factors including electricity rates available (wholesale or retail), distance from end-use, costs for transporting the fuel, and renewable resource availability.

Since electricity is such an important factor for the cost of electrolyzed hydrogen, the electricity rate plays a similarly important role in cost effectiveness of a site. A site must consider both retail rates available in the area and the potential for accessing wholesale markets. Retail rates are independent of location within a service territory. Wholesale pricing nodes can have very different Locational Marginal Prices (LMP) as shown in Figure 24. LMPs in areas of high congestion and long distances from generation, which leads to high loses, have a higher cost than LMPs that are close to the generation source without any congestion. The nodes selected for this analysis have average prices that are in the middle of price range (see Figure 8 and Figure 9).

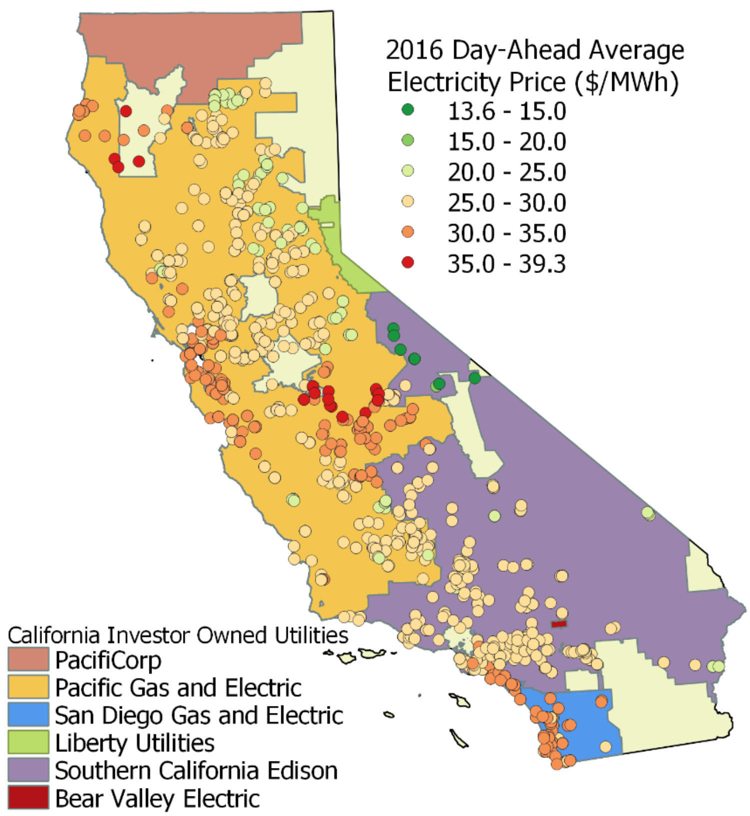


Figure 24. 2016 Day-ahead average electricity prices for California generation nodes[18]

The distance and method of transporting hydrogen must also be considered when determining the least cost location. For instance, the tradeoffs between a gaseous truck, liquid truck and pipeline delivery will affect the cost that a company delivering hydrogen must charge to consumers, which in turn affects the overall cost of hydrogen. Longer distances and lower volumes of product delivery will affect the cost. A map of current and planned station locations curated by the California Fuel Cell Partnership is shown in Figure 25.

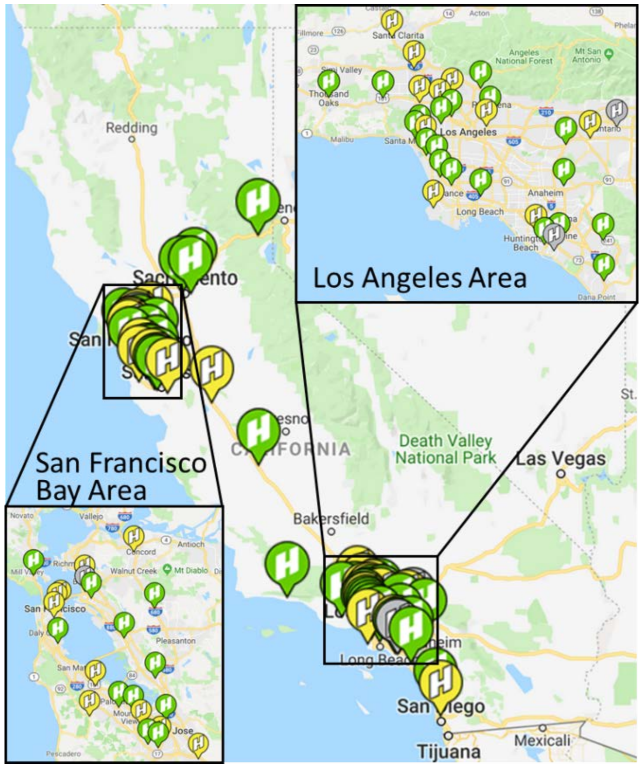


Figure 25. Map of current and planned hydrogen stations in California[35]

Lastly, the land and resource availability for renewable power production and the associated costs of produced power should be considered when siting PV + electrolysis systems. Both land and resource availability are high in the South-Eastern California, while closer to the load centers in cities, the land is more expensive, and the resource is lower. Figure 26 shows the solar resource in California. Similarly, if the systems are placed near renewable power plants that have excess generation from either transmission congestion or lack of demand, then a PV + electrolysis system could more readily access the available energy. Additionally, there are opportunities to locate the electrolysis system near gas pipelines depending on the developments with hydrogen blending in the natural gas system, hydrogen methanation or dedicated hydrogen pipelines. Maps of electricity transmission and natural gas transmission are shown in Figure 27.

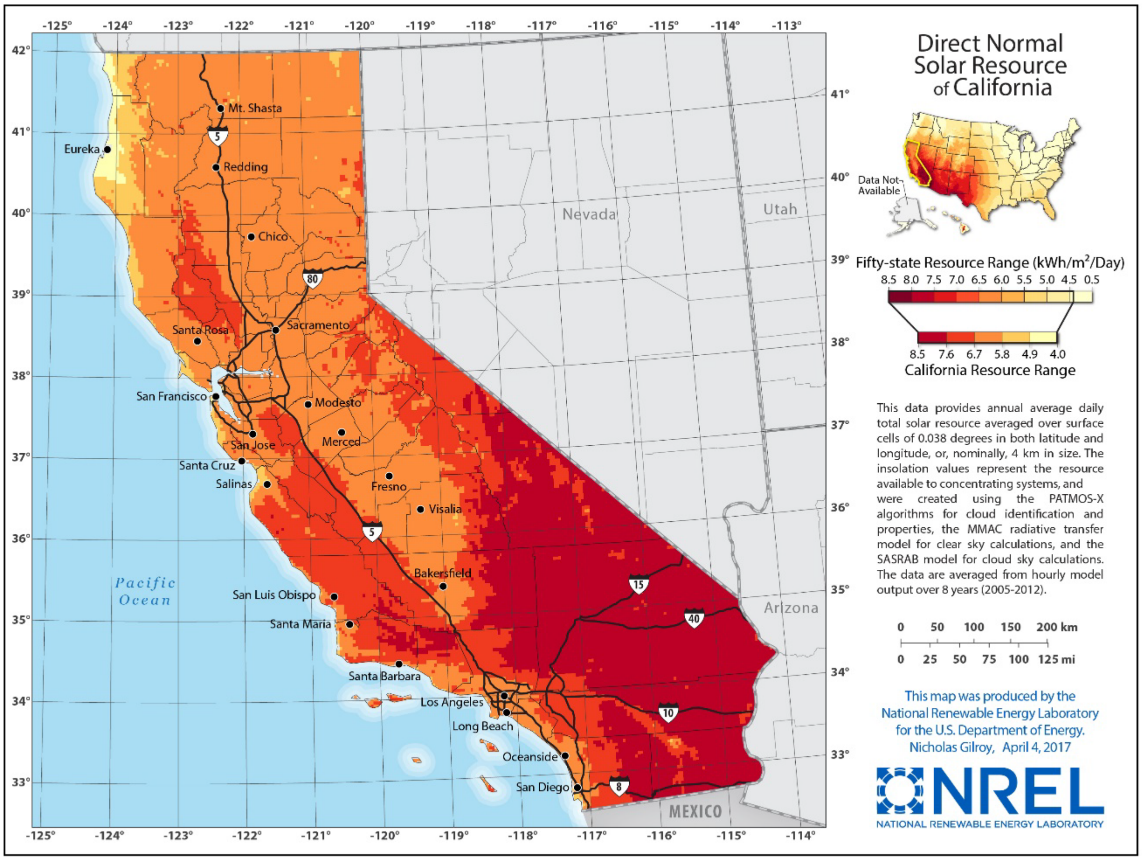


Figure 26. California Direct Normal Solar Resource[xi]

[xi] Solar resource maps produced by NREL can be found here https://www.nrel.gov/gis/solar.html.

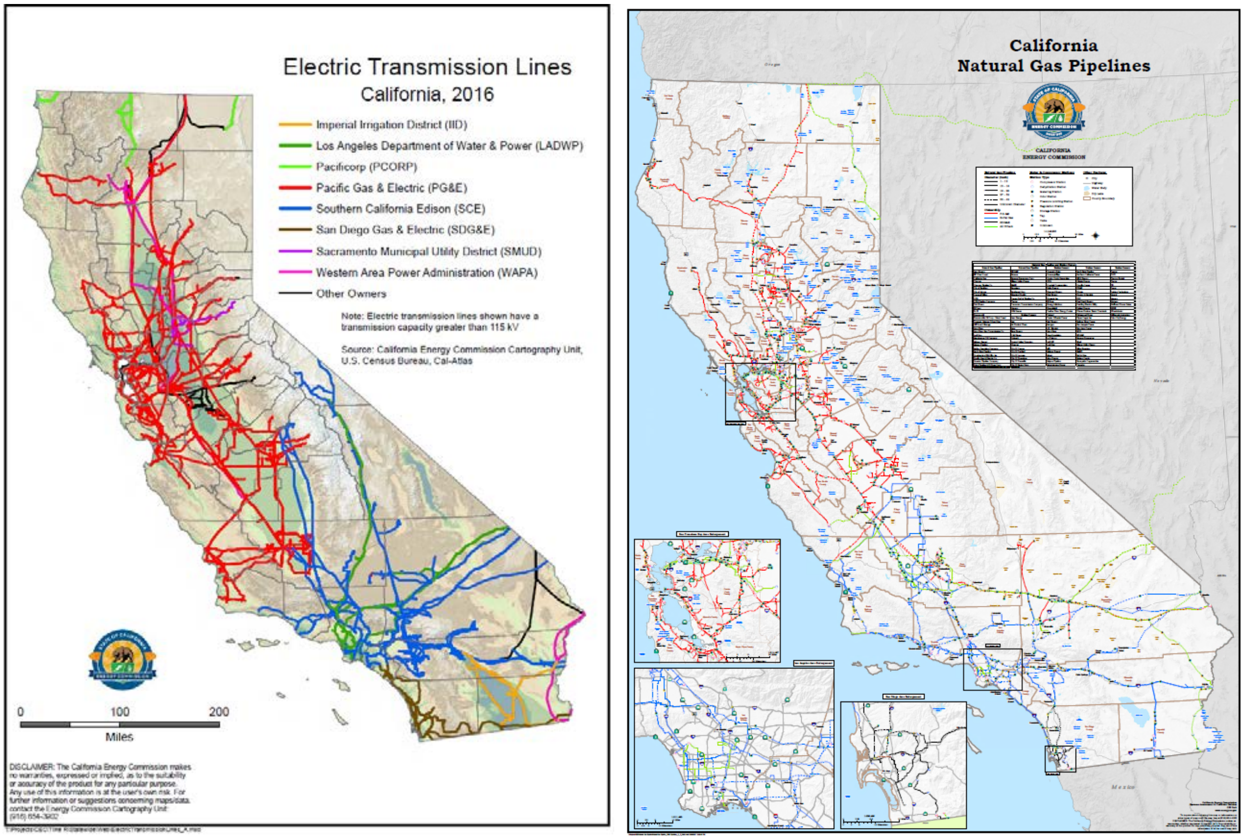


Figure 27. California electric transmission network (left) and natural gas network (right)[36]

At each desired location, it is necessary to balance the importance of electricity prices, land availability and cost, and resource availability as well as proximity to electric or gas infrastructure and fueling stations or other end users. There are several other layers that could be considered as well including ancillary service market prices, water availability, sales and use taxes, etc. As mentioned earlier, retail rates are the same across a utility's service territory while wholesale rates vary for each node across the state.

Comparing Figure 24 to Figure 27, the lowest wholesale electricity prices, are not near fueling stations or large electrical or gas infrastructure. Conversely, closer proximity to stations, electrical infrastructure, and gas infrastructure also typically has wholesale higher electricity prices. One interesting exception is for connector stations or hydrogen end users that are close to lower wholesale price regions. Connector stations could have lower cost wholesale electricity and access to large electricity and gas infrastructure. In summary, the feasibility of PV + electrolysis production centers can be affected by the site selected and the specific properties of the site. Electrolysis system developers should consider the items listed above (and more) when selecting sites.

5.7 Putting the Results in Context

Up to this point, the results have focused on cost reduction potential for PV + Electrolysis systems. It is instructive to compare those costs to those of the incumbent technologies for producing hydrogen. Currently, steam methane reforming (SMR) is the lowest cost technology for producing hydrogen. SMR involves splitting methane to produce hydrogen. The current and future cost values for different SMR technologies from the H2A model are shown in Table 11. Two adjustments are made to the H2A values. These changes include inflation from to 2017 and an additional adjustment of $0.24/kg to reflect the same costs incurred by the electrolysis systems to add sufficient storage and compression to prepare the hydrogen for truck delivery.

The distributed and central electrolysis cases are included for reference. The current production cost values are coincidentally similar to the modeled values with PV. H2A assumes average U.S. electricity price of $57.4/MWh, well below our average of $84/MWh in California for retail, NEM, and hybrid configurations (Figure 16). On the other side, H2A does not include LCFS or REC credits, which reduce the total cost.

Table 11. Hydrogen Cost for Production and Preparation for Delivery Inflated to 2017$[8]

Technology	Hydrogen Production Level (kg/day)	Current (2015) Production cost ($/kg)[xii]	Future (2040) Production Cost ($/kg)[xii]
Distributed SMR	1,500	2.01	2.14
Central SMR without CO_2 sequestration	379,387	1.60	1.80
Central SMR with CO_2 sequestration	379,387	2.08	2.29
Distributed PEM Electrolysis	1,500	6.39	5.27
Central PEM Electrolysis	50,000	6.33	5.21

Similar to electrolysis, SMR feedstock costs make up a greater fraction of the total costs than the capital cost components. Using data from the Annual Energy Outlook, H2A assumes that natural gas prices will rise in the future leading to higher hydrogen production costs. From 2017 to 2037, the price growth is nearly linear going from $6.7/MMBtu in 2017 to $9.21/MMBtu in 2037 (all in 2007$)

Combining all items of the sensitivity analyses (excluding PV profile variability), the hybrid configuration could experience a breakeven cost as low as $4.16/kg, still more than double that of SMR. The wholesale configuration is much closer to competing with SMR. With similar reductions, the wholesale configuration could cost $1.45/kg. That puts the below that of SMR.

[xii] Adjustments to match electrolysis system modeled in this report: 1) Inflated values from 2007 to 2017 by multiplying by 118.1%, and 2) added $0.24/kg to represent on-site storage and compression to prepare hydrogen for truck delivery.

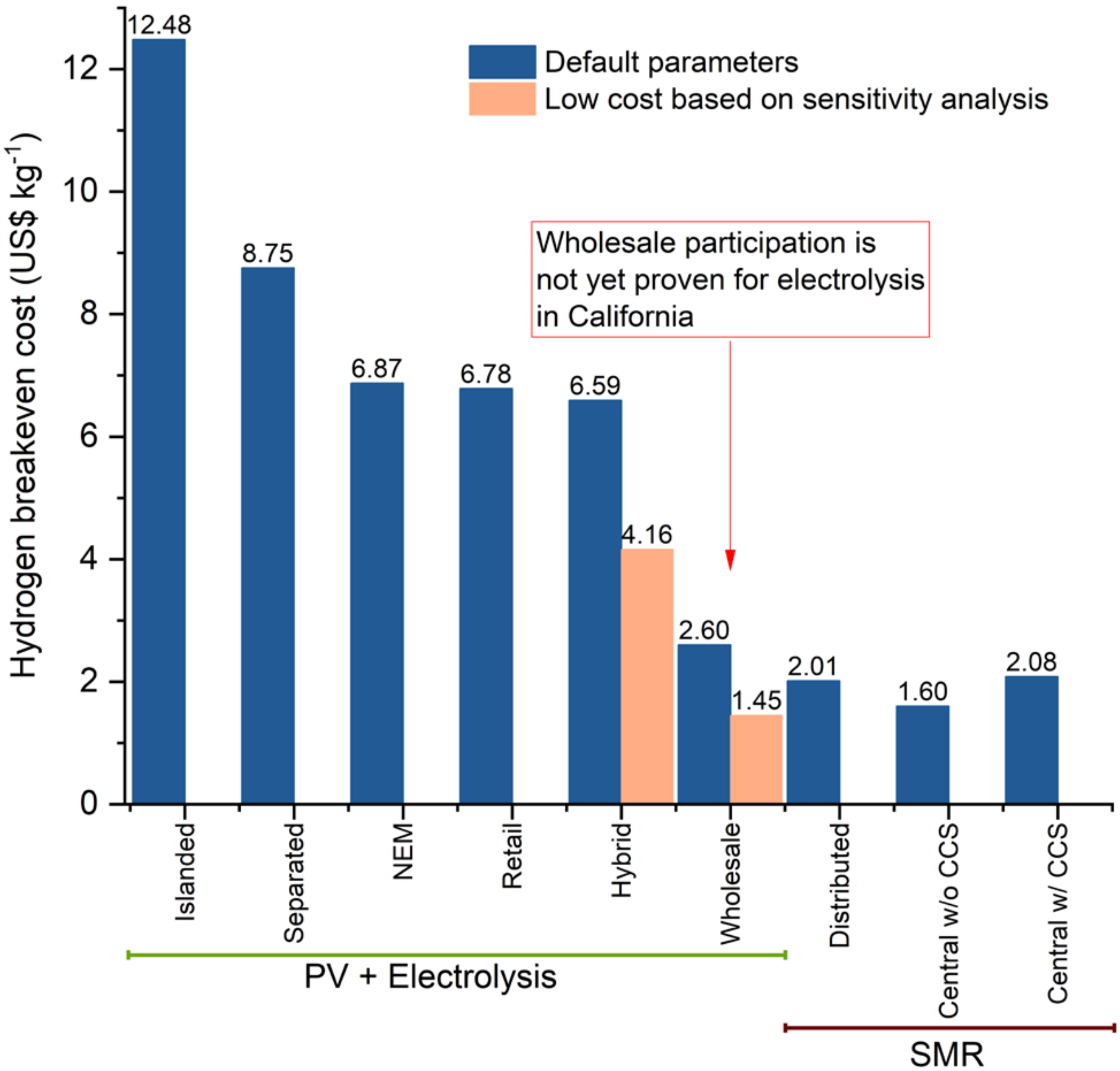


Figure 28. Comparison of PV + Electrolysis and current SMR breakeven hydrogen production cost results inflated to 2017 and with additional costs to prepare the hydrogen for truck delivery.

Comparing SMR production cost to the results for PV + Electrolysis systems shows that renewable integration greatly closes the gap between electrolysis and the incumbent, SMR systems (Figure 28). Hydrogen cost is not the only indicator for economic competitiveness. Competitiveness is also based on a customer's willingness to buy your product. For instance, if there is a hydrogen supply shortage the price that a customer is willing to pay for hydrogen could be much higher than the lowest cost technology option. Similarly, customers that prefer to purchase renewable hydrogen may be willing to pay a premium.

To achieve a renewable hydrogen product an SMR facility could purchase enough renewable credits to offset the non-renewable fuel usage, or directly use biogas to make a net-zero emission fuel. These cases are instructive for understanding the potential value of a renewable premium. If an SMR facility purchases unbundled RECs,[xiii] which cost around \$0.7/MWh,[37] the resulting premium is \$0.04/kg. It is possible that unbundled RECs do not fulfill all the criteria for customers that might want to incentivize specific renewable generation or if legislation requires the purchase of time synchronized RECs. Considering a bundled REC price of \$12/MWh, the renewable premium for hydrogen would be at least \$0.65/kg. The availability of bundled RECs depends on the availability of renewable generation during each hour, which will affect the calculated renewable hydrogen premium price. Alternatively, we can consider directly using biogas to make hydrogen in an SMR facility. The cost for production ranges from \$3.14/kg to \$4.39/kg depending on the level of production (between 300-1000 kg per day).[38] Comparing to the range for SMR costs presented in Table 11 (i.e., \$1.6/kg for central SMR without carbon sequestration and \$2.01/kg for distributed SMR), the renewable premium is between \$1.54/kg and \$2.38/kg. The H2A model also includes an SMR case with carbon sequestration. Comparing the Central SMR case with and without carbon sequestration from Table 11 yields a renewable premium of \$0.48/kg.

In summary, there is no defined premium for renewable hydrogen versus non-renewable hydrogen at this time but looking at the options for a renewable hydrogen equivalent the potential range for a renewable hydrogen premium is shown in Table 12.

Table 12. Potential Premium Values for Converting Hydrogen from Natural Gas SMR to a Renewable or Carbon Free Product

Technology	Premium (\$/kg)
Purchase unbundled RECs[xiv]	0.04
DOE H2A carbon sequestration	0.48
Purchase bundled RECs[xv]	0.65
Biomass fed SMR	1.54 – 2.38

Potential cost reductions in the sensitivity analysis and potential renewable premiums create an interesting situation. While wholesale market participation of electrolyzers is not currently proven in California, somewhere between the hybrid configuration and full wholesale market participation is a solution that will result in a PV + Electrolysis system that is competitive with SMR. When combined with the fact that electrolyzers can operate more flexibly than is required to minimize costs for current retail rates, it appears there is an opportunity to both improve grid operations and reduce the cost of hydrogen production from electrolysis. Utilities and the CAISO

[xiii] Unbundled RECs do not have a timestamp associated with their production, while bundled RECs have the renewable properties and the time of production recorded or "bundled".
[xiv] Due to their origin and nature, unbundled RECs may not satisfy legislation requirements if renewables must be purchased in-state and it also may not satisfy customers that want to stimulate certain renewable production types.
[xv] Bundled RECs may not be available at all times of the day. It depends on the production and timing of renewable sources. As a result, it may be necessary to change electrolyzer operation to coincide with bundled REC availability if an electrolyzer operator wants 100% renewable production.

can benefit from the flexibility of PV + Electrolysis systems and PV + Electrolysis systems can benefit from a more dynamic and, correspondingly, lucrative price signal.

Once PV + Electrolysis can compete with SMR, then there will be a market opportunity for integrating electrolysis into new or existing PV plants. It is also worth noting that there are cost reduction opportunities in addition to future electrolysis equipment cost reductions and other value streams, some are presented in sections 5.4 and 5.5, respectively, which can further improve the economics.

6 Conclusions

Integrating solar PV with electrolysis systems is shown to provide a mutually beneficial relationship from both operational and economic perspectives. With the exception of the islanded system, when PV and electrolysis are integrated, the breakeven cost for producing hydrogen reduces between 20% and 70%. For PV, integration with electrolysis offers the potential to hedge against wholesale market price volatility, particularly in a future with additional PV putting downward pressure on wholesale prices in the afternoon. Additionally, integration with electrolysis may offer the potential to defer or reduce transmission investment to deliver power to the point-of-use.

In order to explore the interactions between PV and electrolysis, the RODeO model was used and several key features were added, including: 1) a more detailed financial model with explicit representation of taxes, debt/equity split, and depreciation, 2) optimization of California NEM rates, 3) integrated optimization of both LCFS and RECs, and 4) an iterative approach for solving non-linear features of the hydrogen price optimization.

Optimal hydrogen production breakeven cost for six market participation configurations is calculated at six candidate locations owned by PG&E that already have PV installed. The cost includes production and preparation for gaseous delivery trucks. Market configurations include 1) islanded, where the PV and electrolyzer do not have a grid connection, 2) separated, where the PV and electrolyzer are installed on two different electricity meters and do not interact, 3) retail only, where all PV generation goes to the electrolyzer and the electrolyzer can purchase additional electricity at retail rates, 4) NEM, where the PV is able to sell back to the grid at retail rates, subject to NEM rules, 5) Hybrid retail/wholesale, where the PV can sell at wholesale rates to the grid and the electrolyzer can either use PV or purchase electricity from the grid on a retail tariff, and 6) wholesale, where the PV and electrolysis system can purchase or sell at wholesale rates. The six candidate locations have PV that varies in size from 2 to 20 MW. A detailed assessment of solar production for each site across 18 years shows that the average capacity factors for all locations is between 23% and 26%.

This report considers a number of revenue streams including the sale of hydrogen, LCFS credits, renewable electricity to the grid, and RECs. We also consider how the electrolyzer can interact with the grid to reduce costs including through retail and wholesale rate optimization. Notably, there are a few other potential revenue streams that are not considered but could potentially reduce the integrated system cost for PV + Electrolysis systems. These include 1) hedging against wholesale market price variability for PV, 2) transmission deferral or avoidance at PV plants, 3) integration with non-flexible loads, and 4) capacity credit value for PV. While we have examined PV + Electrolysis at specific locations, many of the items not considered require even more local information (e.g., availability of nearby non-flexible loads) or forecasted information (e.g., future market prices), so these items are considered out of scope for this report.

Across all locations, the hydrogen production breakeven cost results show that, in the order of decreasing cost, the system configurations are islanded (highest), separated, NEM, retail only, hybrid retail/wholesale, and wholesale (lowest).

- The **islanded** system has the highest cost. While the system does not pay for electricity, the limited availability of PV results in under-utilization of the electrolyzer equipment. The electrolyzer is consistently sized at 60% of the PV, meaning that it is economic to oversize the PV and curtail a portion of the renewable production in order to increase the utilization of the electrolyzer. Additionally, it was found that for an islanded system around one week of storage minimizes the hydrogen production cost by allowing for buffering hydrogen production between days and more importantly across seasons.
- The **separated** system is used to compare to the other integrated cases and has the second highest cost. The PV sells all its energy to the wholesale market and the electrolyzer must buy all its electricity at retail rates. The electrolyzer operates to avoid the peak-time energy and demand charges.
- The **NEM** configuration has the third highest cost, slightly higher than the retail only. This is because of equipment sizing restrictions that require the PV to be less than or equal to the load at a site. As a result, there is no benefit for fully flexible loads to participate in NEM. If the facility had a mixture of flexible and inflexible load, then participation in NEM could potentially lower the cost of the system.
- The **retail** configuration is the third lowest cost and, like the NEM and hybrid configurations, can use rate optimization to significantly reduce the energy costs compared to the separated system.
- The **hybrid retail/wholesale** configuration has the second lowest cost. The preferred electrolyzer size is around 60% of the PV and while the overall hydrogen sales go down, the increases in wholesale PV revenue and reductions in electricity cost result in a lower cost than retail only.
- The **wholesale** configuration has the lowest cost, but as discussed in the report in great detail, it is not currently proven that electrolyzers can get access to wholesale market prices for all hours of the day in California markets, or any other U.S. market for that matter. While there are several programs in California that allow device access to wholesale markets (direct access, NGR, PDR), none are either open or give flexible loads sufficient exposure to wholesale markets. The most promising way to access wholesale prices is for electrolyzers to work with an LSE, ESP or similar entity to make bulk power purchases. Moving from the retail configurations to the wholesale configurations there is a significant reduction in the hydrogen breakeven cost, up to $4/kg. Typical customer loads are less flexible and are not prepared to accept exposure to the variability of wholesale prices; however, through this analysis, electrolyzers as a highly flexible load have shown that they have sufficient flexibility to meet grid needs while also providing hydrogen supply to their customers. Wholesale market access represents an interesting opportunity for electrolyzers and should be pursued.

In addition to the results above, sensitivity assessments are performed for electrolyzer equipment cost, solar production, ITC, equity/debt ratio, and tax rate. Capital and operating cost improvements in line with a transition from current to future electrolyzer costs, according to the DOE H2A model, have the most significant impact, with the potential to reduce the cost of hydrogen production at a PV + Electrolysis facility by 26%. Fluctuations in yearly solar production over the last 18 years are shown to be the second most impactful sensitivity leading to a 6% reduction in hydrogen breakeven price or a 5% increase, depending on the year, for the Vaca-Dixon location. The ITC is the next most impactful sensitivity from 2% to 6% cost reduction for an ITC of 10% or 30%, respectfully. Four tax credit, exemption and exclusion programs specific to California are examined. Each has its own eligibility requirements and would apply to a certain portion of taxes. If the assumed state tax rate of 8.84% is reduced to 5.84%, it would reduce the hydrogen breakeven costs by 0.6%, meaning that the elimination of the California state taxes will have an impact of around 1.8%.

The electrolyzer capacity factor for all configurations, except islanded, is quite high (above 80%). This level, particularly with PV, is enough to limit the peak energy and demand charges, as evidenced by the cost reductions moving from the separated configuration to the retail only configuration. This is an indication that it is often more valuable to sell hydrogen than produce less hydrogen but further avoid peak charges. That finding is for current utility rate structures. As these structures become more "aggressive" (i.e., higher prices during peak periods, or other techniques to more strongly encourage load shaping), the balance between wanting to sell as much hydrogen as possible and wanting to reduce the electricity cost by changing when electricity is consumed will shift. With such a high fraction of the total hydrogen production cost for electrolysis coming from electricity, it is very important that electrolysis units are able to reduce their electricity costs. As a result, if a more aggressive retail rate was offered that provides greater incentive for more flexible operation, electrolyzers would be a good candidate to take service under that rate.

The optimal system designs for NEM, retail only, hybrid retail/wholesale and wholesale have renewable penetrations from 47% to 59%. That means there is a renewable penetration in that range that represents the lowest cost system. This has interesting implications for existing programs and future legislation. Because there is an economic opportunity to pursue high renewable systems, that could mean that encouraging production facilities to produce some fraction of renewable hydrogen in California, on the order of 50%, would not negatively impact project economics and may actually lower the cost. This has consequences for legislation like SB1505 the LCFS program or future legislation.

This report explores what is meant by cost-competitiveness for hydrogen. Beyond the base cost to produce hydrogen, there are other factors that can affect the competitiveness. Hydrogen supply constraints were discussed as well as a discussion on the premium that customers might pay for renewable hydrogen. To better understand renewable hydrogen premiums, we have examined four different alternative techniques to produce renewable hydrogen (i.e., purchasing unbundled RECs, bundled RECs, carbon sequestration and biomass fed SMR) and found that the range is between $0.04/kg and $2.38/kg.

When compared with SMR without considering any renewable hydrogen premiums, current PV + Electrolysis systems are likely not yet competitive; however, with electrolysis cost reductions in line with DOE's estimates, it was found that systems with wholesale market access are competitive, because of both low capital cost and low-cost electricity. In addition, electrolysis units can provide greater flexibility than what is required to optimize retail rates, so there is an opportunity for a utility or CAISO to increase system flexibility with PV + Electrolysis systems in return for commensurate compensation. In this way, there are potentially several solutions that fall between the hybrid configuration and the wholesale configuration that could provide sufficient compensation for a PV + Electrolysis unit to compete with SMR while also providing greater flexibility to the grid.

7 Future Work

The wholesale configuration for PV + Electrolysis was very effective at reducing the breakeven cost of hydrogen, even with an additional transmission and distribution adder for purchased electricity. This area represents a valuable area for future study. There is a need to understand what wholesale market participation for an electrolyzer or any flexible load could look like and, importantly, the implications for introducing that level of market participation.

This study also found that electrolyzers are highly responsive to the retail rate structures and are able to largely avoid peak energy and demand charges by reducing production during those hours. Additionally, electricity costs make up a large portion of the total costs, between 33% for wholesale and 76% for separated configurations. Systems with a higher fraction of electricity costs are more likely to be interested in more aggressive rate structures to further reduce their costs by providing more flexible operation. Only one rate was analyzed in this report, PG&E E-20. It would be instructive to examine new rates and unique rate strategies that could allow the electrolyzer to provide more flexibility to the grid and receive a lower electricity cost.

Only integration with PV was explored in this report, but there is a collection of other renewable resources, (e.g., wind or concentrated solar power) that could benefit from integration with electrolysis. The benefit is likely to occur in a similar way as with PV in the form of lower overall system cost for the combined system, hedging against wholesale market variability and the potential for transmission investment deferral or avoidance.

Lastly, this report did not examine the potential benefits of integrating PV and flexible loads with other existing non-flexible loads. Even without any flexibility, load aggregation is a good way to reduce retail rate costs. Combining with flexible loads and also integrating with electricity markets including ancillary services can have even a greater cost reduction potential.

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Appendix A. Breakeven Hydrogen Production Cost Bar Charts for Other Locations

A detailed breakdown of the cost components for the other five sites is presented in the figures below.

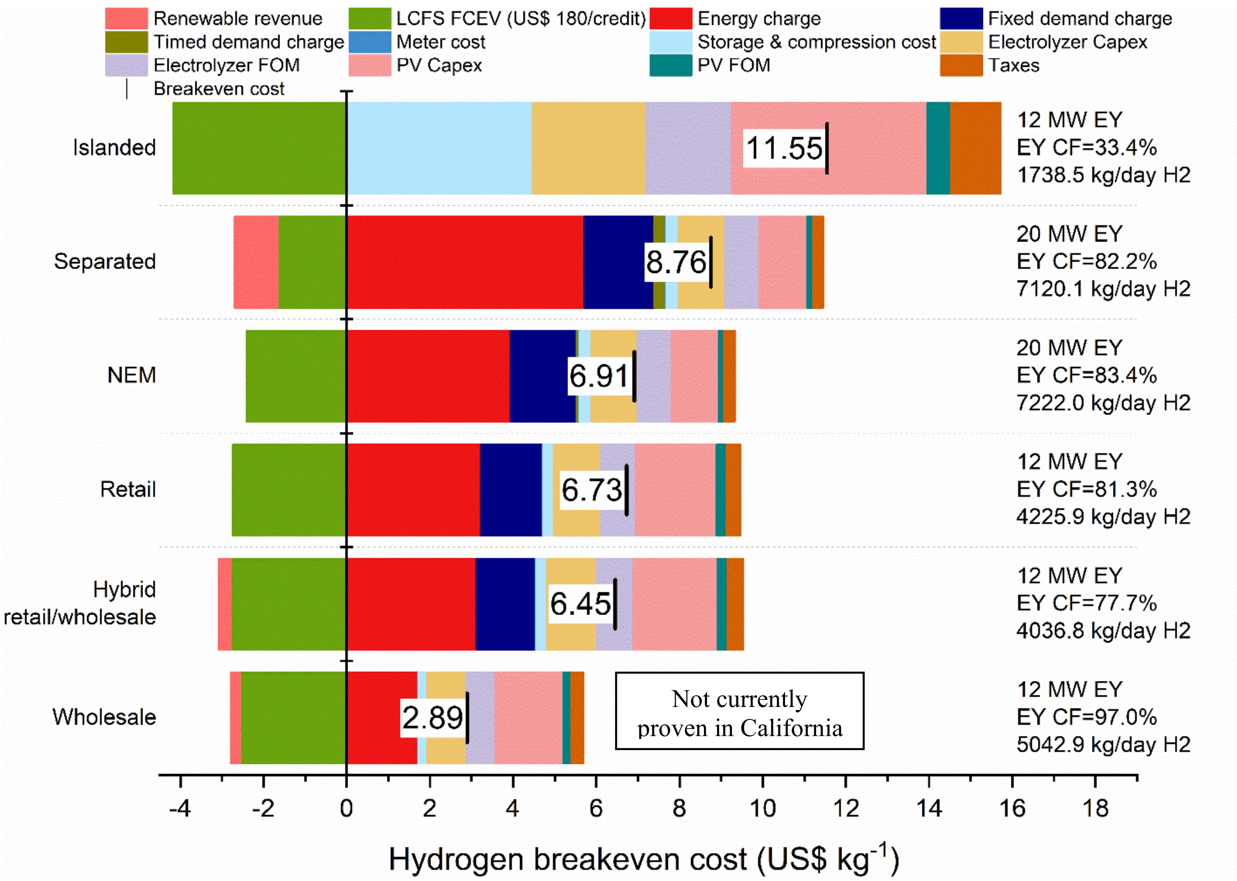

Figure 29. Comparison of breakeven hydrogen production cost for Stroud with 20 MW of PV

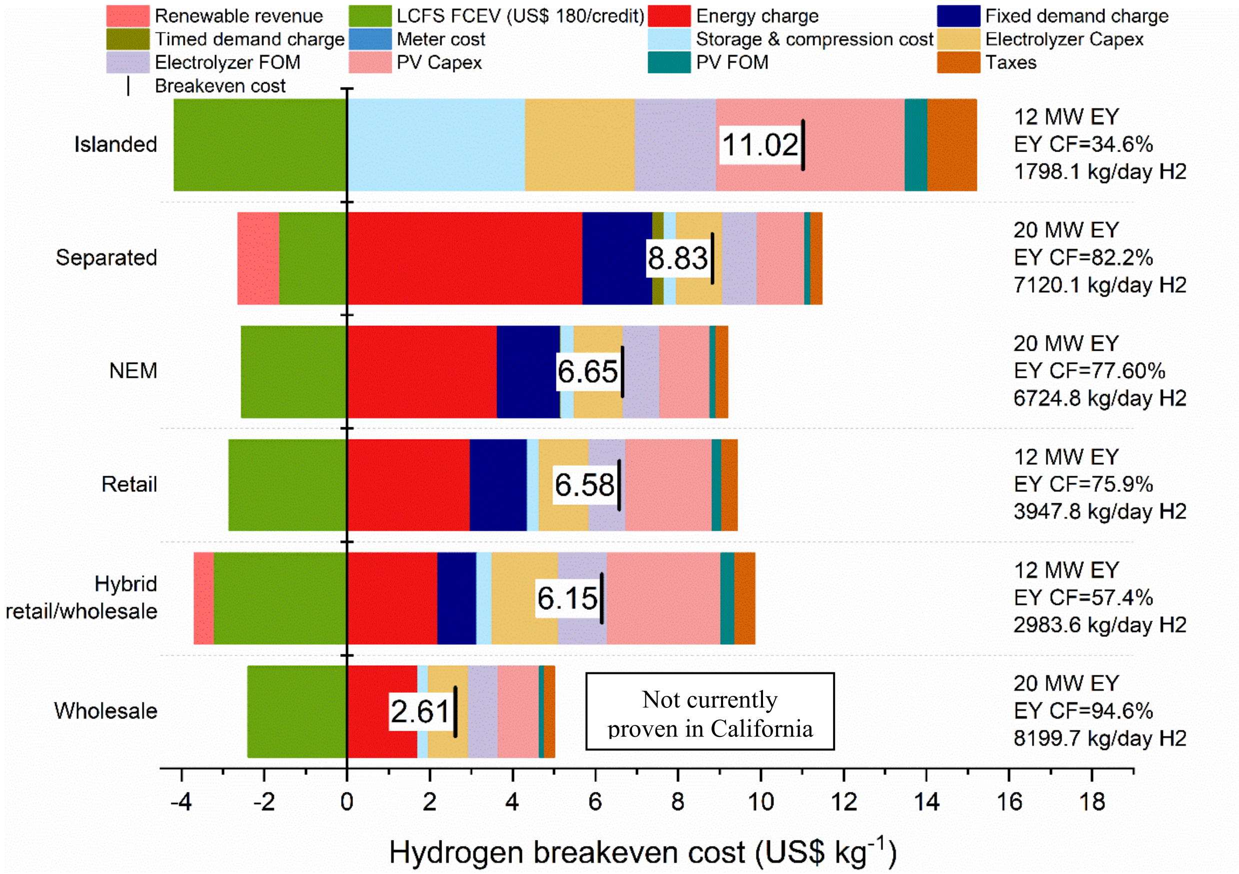

Figure 30. Comparison of breakeven hydrogen production cost for Huron with 20 MW of PV

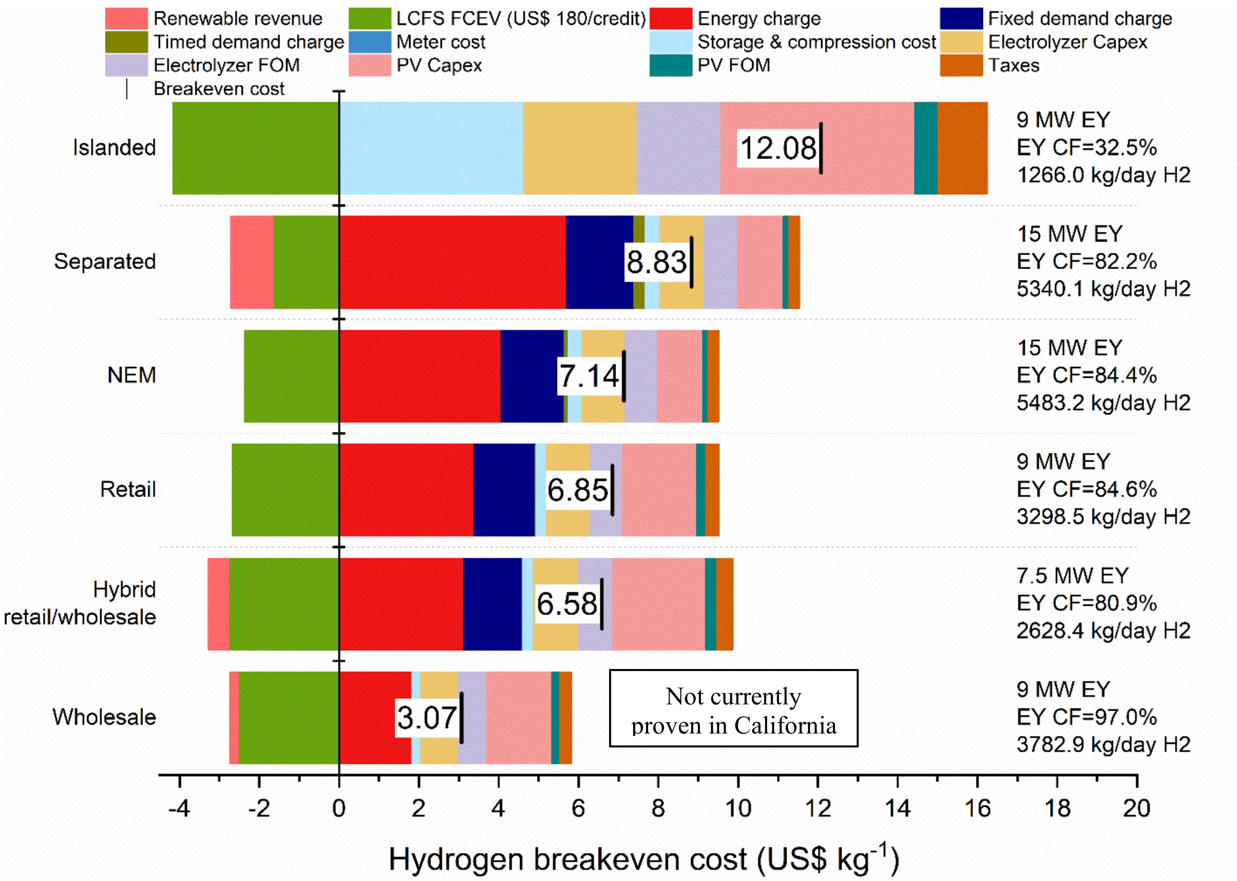

Figure 31. Comparison of breakeven hydrogen production cost for Five Points with 15 MW of PV

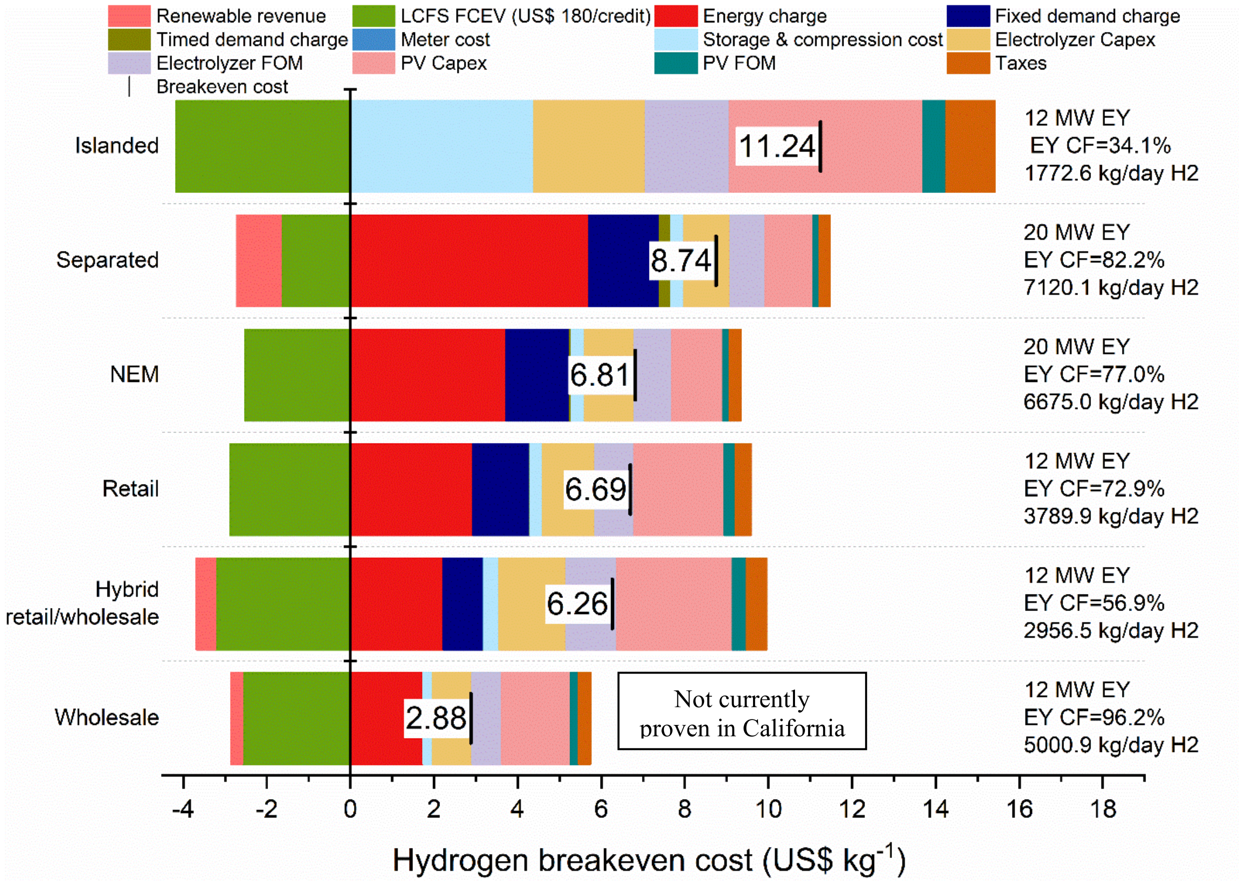

Figure 32. Comparison of breakeven hydrogen production cost for Cantua with 20 MW of PV

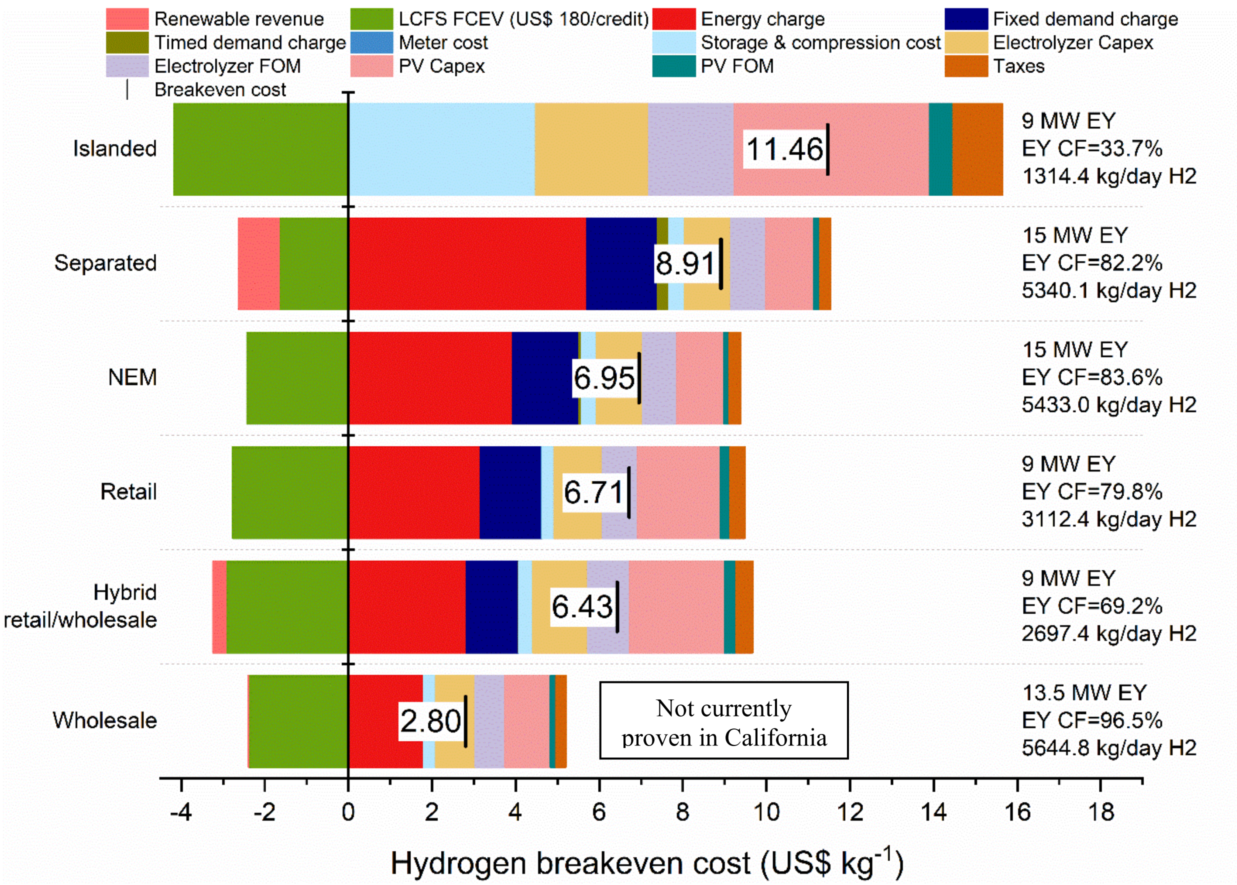

Figure 33. Comparison of breakeven hydrogen production cost for Westside with 15 MW of PV