Economic Assessment of Hydrogen Technologies Participating in California Electricity Markets

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National Renewable Energy Laboratory

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List of Abbreviations and Acronyms

CAISO	California Independent System Operator
FOM	fixed operation and maintenance
FC	fuel cell
NREL	National Renewable Energy Laboratory
SMR	steam methane reformer
VOM	variable operation and maintenance

Executive Summary

As the electric sector evolves and increasing amounts of variable renewable generation are installed on the system, there are greater needs for system flexibility and sufficient capacity, and greater concern for overgeneration from renewable sources not well matched in time with electric loads. Hydrogen systems have the potential to support the grid in each of these areas. However, limited information is available about the economic competitiveness of hydrogen system configurations.

This paper quantifies the value for hydrogen energy storage and demand response systems to participate in select California wholesale electricity markets using 2012 data. For hydrogen systems and conventional storage systems (e.g., pumped hydro, batteries), the yearly revenues from energy, ancillary service, and capacity markets are compared to the yearly cost to establish economic competitiveness.

Hydrogen systems can present a positive value proposition for current markets. Three main findings include:

1. For hydrogen systems participating in California electricity markets, producing and selling hydrogen was found to be much more valuable than producing and storing hydrogen to later produce electricity; therefore systems should focus on producing and selling hydrogen and opportunistically providing ancillary services and arbitrage.
2. Tighter integration with electricity markets generates greater revenues (i.e., systems that participate in multiple markets receive the highest revenue).
3. More storage capacity, in excess of what is required to provide diurnal shifting, does not increase competitiveness in current California wholesale energy markets.

As more variable renewable generation is installed, the importance of long duration storage may become apparent in the energy price or through additional markets, but currently, there is not a sufficiently large price differential between days to generate enough revenue to offset the cost of additional storage. Future work will involve expanding to consider later year data and multiple regions to establish more generalized results.

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1 Introduction

Hydrogen is a versatile element that can be used in a variety of applications including chemical and industrial processes (Bourgeois 2007; Ramachandran and Menon 1998), as a transportation fuel (Green et al. 2008), and as a heating fuel for heating, cooking, power generation, etc. (De Vries et al. 2007; Gahleitner 2013). Traditionally, hydrogen technologies focus on providing services to only one sector; however, because of the versatility of hydrogen, it has the ability to enable multi-sector interactions between transportation, electricity, commercial, and industrial sectors. There are a variety of challenges in each sector: for example, clean and inexpensive fuels are needed for the transportation sector, grid balancing and renewable integration are needed for the electricity sector, and clean and inexpensive feedstocks are needed for chemical and industrial uses. By engaging multiple sectors, hydrogen has the potential to provide benefits to each sector and increase its revenue streams.

There is a strong interest in exploring opportunities to supplement revenue while supporting the electric grid; however, there are limited studies that explore the economic value of hydrogen-based energy systems, and even fewer that focus on North America. The goal of this study is to explore promising configurations for hydrogen systems that can interact with the electric grid and sell hydrogen. System configurations include both energy storage and demand response. Several conventional energy storage technologies are included in this study for comparison. This comparison is essential to facilitate a discussion of wider implementation of hydrogen technologies. Revenues are calculated by co-optimizing energy, ancillary services, and hydrogen production to maximize operational profits.

To determine economic competitiveness, revenues from providing grid services and the sale of hydrogen are compared to the capital cost and operating expenses over the lifetime of the equipment. Results focus on the achievable value from several selected current electricity markets in California and include energy and ancillary services for grid balancing and reliability, as well as capacity for resource adequacy.

2 Previous Studies on Grid Revenue Calculation and Hydrogen Flexibility

Several studies have analyzed the concept of using electrolyzers both with and without fuel cells to smooth renewable generation, provide grid services, and benefit from the price difference in on-peak and off-peak electricity (Kroposki et al. 2006; Saur and Ramsden 2011; Steward et al. 2009; EY et al. 2013). These studies establish that there are opportunities for electrolyzers to access lower cost electricity for hydrogen production by making use of different electricity markets and rate structures as well as utilizing curtailed renewable energy. The potential of integrating renewables with hydrogen technologies was demonstrated in projects at the National Renewable Energy Laboratory (NREL) (Harrison et al. 2009) and the University of North Dakota (Rebenitsch et al. 2009), among others. These projects demonstrate how renewable generation can be combined with electrolyzers to generate renewable hydrogen that can be used for a variety of applications. One application receiving growing interest, particularly in Germany, is injection of hydrogen or methanized hydrogen into the natural gas pipeline (Gahleitner 2013; EPRI 2014; Grond et al. 2013). Methanation is the process by which carbon oxides are combined with hydrogen to form methane. This idea, also called power-to-gas, could enable greater uptake of curtailed renewables by providing supply-side flexibility for the electricity sector while reducing carbon dioxide emissions for systems using the natural gas grid.

The technical feasibility for hydrogen technologies to participate in electricity markets has been explored by Eichman et al. (2014), Hydrogenics (2011), and ITM Power (2014). It was found that electrolyzers are sufficiently responsive to provide grid services including operating reserves, frequency regulation and load-following. These studies show that there is both interest and potential for hydrogen technologies to participate in wholesale electricity markets and opportunity to enhance their revenue.

For this study, an operations optimization model is used to calculate the revenue from participation in one or more markets. The model optimizes revenue from electricity, ancillary service, and hydrogen production markets using historical price data to determine the maximum achievable revenue under the assumption that the equipment is not large enough to impact the electricity and hydrogen market prices. This “price-taker” approach has been used extensively for optimization within energy markets (Sioshansi et al. 2009; Spisto 2014) and also for co-optimization of both energy and ancillary services markets (Cutter et al. 2014; Drury et al. 2011; Kirby 2012). More detail on the model is provided in the following sections. In addition to exploring value from different services, those other studies explore the differences in the value of storage for different sizes, locations (California Independent System Operator [CAISO], Pennsylvania-New Jersey-Maryland Interconnection, New York Independent System Operator, and Italy), years (2002–2013), and technologies (pumped hydro, combustion turbine, compressed air energy storage, and conventional battery). Those studies also look at the importance of uncertainty in optimal dispatch. Storage revenue values ranged from $12/kW-yr to $94/kW-yr for systems providing only energy and from $33/kW-yr to $143/kW-yr for systems providing both energy and ancillary services.

To the authors’ knowledge the present work represents the first time that this strategy has been applied to hydrogen technologies. The goal of this work is to assess the economic viability of hydrogen storage systems and determine the revenue potential for participating in selected electricity markets. This study includes an assessment of the day-ahead energy market and several ancillary services: frequency regulation up and down, spinning reserve, and non-spinning reserve. The prices are all drawn from the day-ahead markets. This study does not consider real-time market prices or potential future market products including flexible ramping and reactive power.

3 Hydrogen System Configurations

Three hydrogen technologies were analyzed: electrolyzers (EY), hydrogen fuel cells (FC), and steam methane reformers (SMR). While there are many different types of fuel cells and electrolyzers, generally, a fuel cell electrochemically combines oxygen and hydrogen to generate electricity and water. Similarly, an electrolyzer electrochemically converts electricity and water to hydrogen and oxygen. A steam methane reformer splits methane through a series of chemical reactions to produce hydrogen and carbon dioxide.

Figure 1 provides a schematic for how each piece of equipment interacts with the electricity and natural gas grids. Electrolyzers and hydrogen fuel cells interact with the electric grid and produce or consume hydrogen while providing grid services. The steam methane reformer and pipeline injection, either directly or using methanation, interact with the natural gas grid and produce or consume hydrogen. In this way produced hydrogen, particularly from electrolyzers, can be stored in the natural gas grid. While not considered in this work, it is also possible to selectively remove injected hydrogen from the natural gas system at some downstream location (Melaina et al. 2013). That pathway could be especially appropriate for large penetrations of hydrogen injection. Hydrogen or natural gas on the gas grid can be used by fuel cells or conventional combustion-based generation equipment to generate electricity. Additionally, by using a renewable source of electricity electrolyzers can produce renewable hydrogen. Hydrogen made from the electrolyzer or reformer can be used in any of the output equipment including a fuel cell for power generation, fuel cell vehicles, chemical and industrial processes, or for pipeline injection. This work includes explicit modeling of the electrolyzer, stationary hydrogen fuel cell, and steam methane reformer, but it does not differentiate on the downstream uses of hydrogen for vehicles, pipeline injection, or industrial processes; rather it assumes a price that hydrogen is sold independent of the market.

The flexibility of hydrogen systems creates many opportunities for system design. Different combinations of equipment can enable interactions with different sectors; however, not all pathways represent viable business cases in the near-term. The purpose of the following analysis is to establish which configurations are economically viable and discuss which configurations offer unique opportunities with current near-term market conditions. System configurations for this analysis are discussed in a later section and involve a variety of combinations of the hydrogen equipment presented in Figure 1.

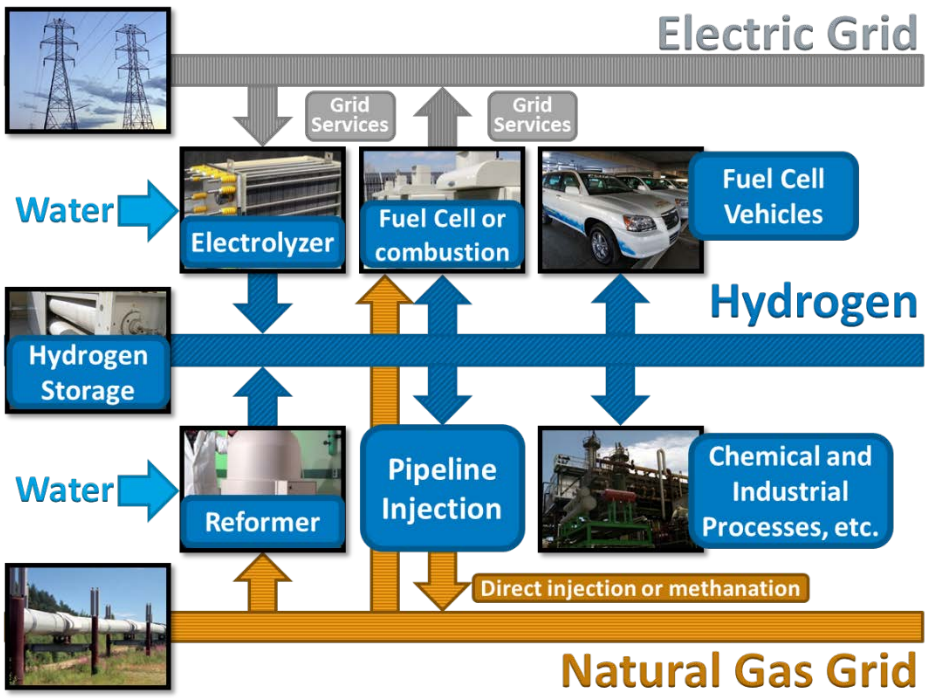

Figure 1. Hydrogen technology configurations

Photos by: (from top left by row) Warren Gretz, NREL 10926; Matt Stiveson, NREL 12508; Keith Wipke, NREL 17319; Dennis Schroeder, NREL 22794; NextEnergy Center, NREL 16129; Warren Gretz, NREL 09830; David Parsons, NREL 05050; and Bruce Green, NREL 09408

4 Modeling Approach and Data Sources

To explore the value of hydrogen systems the maximum achievable revenue is calculated using an optimization model (section 4.1) and compared to the annualized system cost from a cost model (section 4.2) to determine economic competitiveness for twelve scenarios (section 4.3). Revenue streams include energy, ancillary service, and capacity markets as well as the sale of hydrogen at a range of prices to reflect different products. Not all electricity market products are modeled herein. This analysis uses day-ahead historical data for California electricity markets. A variety of end uses for hydrogen can be considered and this study focuses on the highest valued products, which are presently sale as a transportation fuel or as an industrial product.

The ancillary service markets explored for this analysis include regulation up and down, spinning reserve, and non-spinning reserve. Flexible ramping products are not included in this analysis. Regulation up and regulation down are used to maintain grid frequency by balancing energy imbalances. Regulation up means adding power from a generation source (or decreasing load), while regulation down means reducing input power or increasing load. Spinning and non-spinning reserves are used in contingency events where regulation and other responsive markets are not able to sufficiently correct an energy imbalance, for example in the event of a generator failure. As their names suggest, spinning reserve is capacity available for dispatch immediately while non-spinning reserve is capacity that is not online but can rapidly turn on.

Hourly day-ahead electrical energy and ancillary service prices for 2012 are taken from CAISO's Open Access Same-Time Information System (CAISO 2015). Monthly natural gas prices for California are drawn from the Energy Information Administration (EIA 2014). The historical average and range of CAISO prices for 2012 are shown in Table 1. The average price of energy is the highest, followed by regulation up and down, then spinning reserve and non-spinning reserve. While provision of energy is compensated for each unit of energy provided ($/MWh), ancillary services are typically offered as capacity products ($/MW) and called upon as necessary, and capacity value is a yearly payment based on the capacity provided ($/MW-yr). Systems that are held for reserves receive the reserve price and if they are called to provide energy, they receive the energy price.

Table 1. Historical Energy, Ancillary Service, and Natural Gas Prices for CAISO in 2012[a]

	Electricity ($/MWh)	Reg. Up ($/MW)	Reg. Down ($/MW)	Spin Res. ($/MW)	Non-Spin Res. ($/MW)	Nat. Gas ($/MMBtu)	Capacity Value ($/MW-yr)[b]
Average	30.0	5.7	4.4	3.3	0.9	3.6	150
Maximum	179.4	129.7	25.6	129.7	129.7	4.4	150
Minimum	-59.4	0.0	0.0	0.0	0.0	3.0	150

[a] CAISO (2015); EIA (2014)
[b] Pfeifenberger et al. (2012)

4.1 Revenue Optimization

For this analysis, a variety of revenue streams are evaluated: energy revenues, ancillary service revenues, capacity revenues, and hydrogen sales. Revenues are maximized using an operations optimization model. These streams are described below.

Energy services include the purchase and sale of electricity. Ancillary services for this analysis include regulation up and down, spinning reserve, and non-spinning reserve. The value of providing capacity resources varies based on the type of capacity provided. New capacity to support resource adequacy within California can be valued at \$150–\$300/kW-yr according to Pfeifenberger et al. (2012). A value of \$150/kW-yr is selected as the capacity revenue based on the cost for new market entry.

The last revenue stream is from the sale of hydrogen produced at a facility. This analysis only includes the cost of production and not compression or delivery costs for sale to customers. A range of hydrogen production prices from \$3/kg to \$10/kg are explored. This range represents the range of potential prices at which hydrogen can be sold from a production facility. The low value represents the U.S. Department of Energy target of \$2–\$4 per gallon gasoline equivalent without tax (DOE 2012). Because one gallon of gasoline contains the same energy content as one kilogram of hydrogen on a lower heating value basis (33.3 kWh), the target of \$2–\$4 per gallon gasoline equivalent can be translated to \$2–\$4 per kilogram hydrogen for production only (which does not include compression or delivery). The high value of \$10/kg is selected for comparison. Depending on the market where hydrogen is sold, the sale price of hydrogen will be different. For example, selling hydrogen as a heating fuel in North America returns a lower value than does selling it as a transportation fuel or industrial product. Using a range enables the reader to select a value for hydrogen and judge its competitiveness.

The objective of the model is to maximize the operational profits of the candidate system. The operational profits are the sum of its revenues (including net revenues from electricity [$R_{Electricity}$], ancillary services [R_{AS}], capacity [$R_{Capacity}$] and hydrogen [R_{H2}]) less the sum of its costs (including assumed cost of natural gas [R_{NG}], variable operations and maintenance costs [R_{VOM}], and startup costs [$R_{Startup}$]) as shown in Equation 1.

$$\text{Operational Profits} = R_{Electricity} + R_{AS} + R_{Capacity} + R_{H2} - R_{NG} - R_{VOM} - R_{Startup} \qquad \text{Eq. 1}$$

In general, the system can earn revenue by performing price arbitrage (buying electricity when the electricity price is low and storing the energy until the electricity price is high), providing ancillary services to the grid, providing system capacity, or, for hydrogen technologies, producing and selling hydrogen. The operations optimization model determines which of these operations the system should pursue at each time step in order to maximize its operational profit. This optimization takes into account system parameters including efficiency, power capacity, energy capacity, and minimum part-load (i.e., maximum turndown) as shown in Table 2. Sources for the values in Table 2 are listed in the notes below the table. The first two technologies, pumped hydro and lead acid batteries, provide a comparison to conventional energy storage. Hydrogen technologies include a stationary hydrogen fuel cell, an electrolyzer, and a steam methane reformer. Many of the sources for cost values are not specific about the type of fuel cell or electrolyzer. Based on the assumed minimum part load and efficiencies in Table 2, this study most closely reflects a proton exchange membrane fuel cell but also could be extended to an alkaline fuel cell or electrolyzer.

Table 2. Technology Assumptions

Properties	Pumped Hydro	Lead Acid Battery	Stationary H_2 Fuel Cell	Electrolyzer	Steam Methane Reformer
Rated power capacity (MW)	1.0	1.0	1.0	1.0	400 kg/day
Energy capacity (h at rated capacity)	8	4	8	8	8
Capital cost ($/kW)	1,500[a]–2,347[b]	2,000[a]–4,600[a]	1,500[c]–5,918[b]	430[c]–2121[d]	427–569 $/kg/day[e]
Fixed O&M ($/kW-yr)	8[a]–14.27[b]	25[a]–50[a]	75–296 (5% of capital)	42[e]	5.14–5.92 % of capital[e]
H_2 storage cost ($/kg)	-	-	623[f]–1000	623[f]–1000	623[f]–1000
Installation cost multiplier	1.2	1.2	1.2[e]	1.2[e]	1.92[e]
Lifetime (yr)	30	12[a] (4,400 h)	20	20[e]	20[e]
Interest rate	7%	7%	7%	7%	7%
Efficiency	80% AC/AC[a]	90% AC/AC[a]	40% LHV	70% LHV	0.156 MMBtu/kg[e] 0.6 kWh/kg[e]
Minimum part-load	30%[g]	1%	10%	10%[h]	100%[i]

[a] EPRI (2010).
[b] EIA (2012).
[c] DOE (2012).
[d] Saur (2008).
[e] DOE (2015).
[f] Steward et al. (2009).
[g] Levine (2003).
[h] Eichman et al. (2014).
[i] SMR unit power can be modulated but because the electric consumption for SMR is minimal and this study is focused on assessing electric grid impacts, for this study it is assumed that SMR operates baseload.

Based on the input prices and values in Table 2, the model can calculate the maximum revenue from operating each system. Figure 2 shows an example operation of a hydrogen energy storage system consisting of an electrolyzer, storage container, and fuel cell for two consecutive days. The top left figure shows the power level for the hydrogen fuel cell and electrolyzer. Negative values represent electricity consumption by the electrolyzer and positive values represent electricity generation by the fuel cell. The top right figure shows inputs (electrolyzer) and outputs (fuel cell and sale of hydrogen) from the storage system. The bottom two figures show the ancillary services that can be provided. Notice the mixture of services. In each time step the system might do one or more of the following: sit idle; buy electricity and store or sell hydrogen; use hydrogen to generate and sell electricity; provide one or more ancillary services; or any combination of these activities. For this analysis, time steps are hourly for an entire year, based on the availability of pricing data; however, the process is the same for data with higher temporal resolution.

For generators, electricity production and provision of ancillary service is more straightforward to describe. A device can generate electricity for energy markets with part of its capacity (down to its minimum part-load point) and provide ancillary services with the remaining capacity. A generator can provide upward reserve products (regulation up and spinning reserve) with the remaining unused capacity and downward products (regulation down) with the capacity that it is provided to energy markets. The generator must be off or idle to provide non-spinning reserve. The principle is similar for demand response devices (e.g., electrolyzers) but in reverse. An electrolyzer can reduce its electricity consumption to reduce demand on the grid and act as a virtual power plant while also providing ancillary services. A demand response device can direct unused capacity to provide downward reserve products and can provide upward products with the capacity that is consuming electricity.

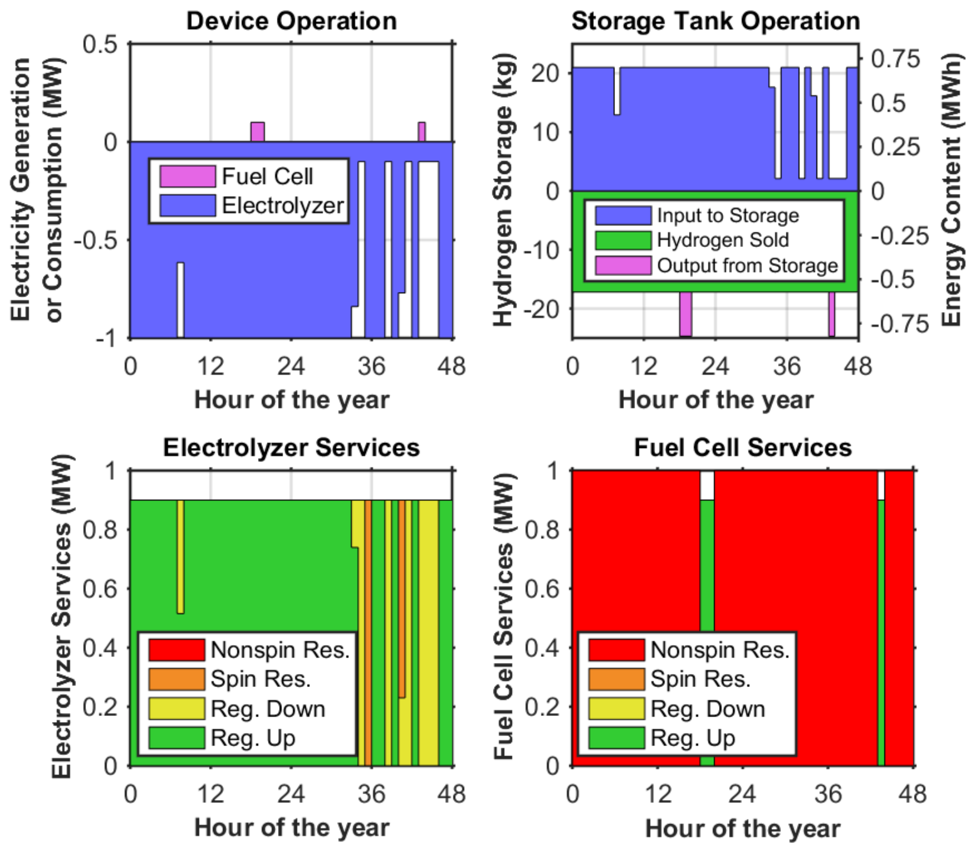

Figure 2. Example of optimized operation for an electrolyzer and fuel cell storage system for two consecutive days

The modeled system is subject to several constraints. Constraints include the minimum and maximum output and input power levels for the electrolyzer and fuel cell, minimum and maximum storage levels, maximum ancillary service provision,[1] minimum operation conversion

[1] Maximum ancillary service provision establishes the range of capacity that a system can bid into the ancillary service markets. This depends on both the storage system and the market in which it is operated. For this analysis we assume that storage systems can offer their full capacity to ancillary service markets as long as the minimum power levels are respected.

efficiency, and hydrogen sales requirements. All these constraints are preserved during model operation. Apart from the maximum ancillary service provision constraint, it is assumed that there are no limitations on operational flexibility (i.e., each system can handle ramp rates greater than its maximum power per interval length of one hour [Eichman et al. 2014]).

The model accepts as inputs the electricity and ancillary services prices, hydrogen prices, and operational characteristics of the candidate system and returns the maximum achievable operating profits that the system could earn. The model has perfect knowledge of all prices in the year, and therefore the optimization achieves the maximum possible operational profits. Additionally, this model assumes that the systems are sufficiently small such that their operation does not affect any of the system prices. Revenue calculations are shown below and additional details on the price-taker formulation are shown in Townsend (2013).

The net revenues from electricity can be expressed as follows:

$$R_{Electricity} = \sum_{i=1}^{n} P_i^{elec} \cdot \left(x_i^{pwr} - y_i^{pwr}\right) \qquad \text{Eq. 2}$$

where P^{elec} is the price of electricity at any time t, x^{pwr} is the output device power (e.g., fuel cell, turbine, other generator) and y^{pwr} is the input device power (e.g., electrolyzer, SMR, compressor, other charging device). In the case of batteries the output and input devices are the same. The net revenue for electricity is the sum of all intervals from time, i=1, to the end of the simulation, n (i.e., one year in hourly time steps).

Revenues for ancillary services are calculated as follows:

$$R_{AS} = \sum_{i=1}^{n} P_i^{RU} \cdot \left(x_i^{RU} + y_i^{RU}\right) + P_i^{RD} \cdot \left(x_i^{RD} + y_i^{RD}\right) + P_i^{SP} \cdot \left(x_i^{SP} + y_i^{SP}\right) + P_i^{NS} \cdot \left(x_i^{NS} + y_i^{NS}\right) \qquad \text{Eq. 3}$$

where P is the price, x is the output device, y is the input device, and the superscripts refer to each ancillary service product. RU is regulation up, RD is regulation down, SP is spinning reserve, and NS is non-spinning reserve. Devices can generate or consume electricity while also providing reserves as long as the operational parameters are not violated (e.g., minimum and maximum power level and the maximum ancillary service provision).

Resource adequacy capacity revenue ($R_{Capacity}$) is the product of the assumed capacity value (e.g., \$150/kW-yr for new market entry) and the equipment power capacity (e.g., 1 MW). The result is a fixed payment for technologies that can provide dispatchable capacity.

For devices that use natural gas for fuel (only the SMR in this study), the cost of fuel must also be considered as follows:

$$R_{NG} = \sum_{t=1}^{n} P_i^{NG} \cdot \left(HR_x \cdot x_i^{pwr} + HR_y \cdot y_i^{pwr}\right) \qquad \text{Eq. 4}$$

where P^{NG} is the price of natural gas and HR_x and HR_y refer to the heat rate (i.e., thermal energy in divided by electrical energy out) for the output and the input devices, respectively.

The model has the ability to include the impact of variable operation and maintenance (VOM) on the revenues. Currently, hydrogen systems deployed to date have a relatively flat operating profile and are not dispatched to provide ancillary services. As a result, an empirical basis for the VOM price (P_{VOM}) is not available. For this analysis the VOM price for both the input and output devices is assumed to be zero. As dynamic operation of hydrogen equipment increases and these values become available, they can be included in the analysis as follows:

$$R_{VOM} = \sum_{t=1}^{n} P_{VOM,x} \cdot x_i^{pwr} + P_{VOM,y} \cdot y_i^{pwr} \quad \text{Eq. 5}$$

Similarly, the ability to implement a startup cost is integrated into the model (Equation 6), but a representative cost for a startup (P_{start}) has not yet been identified from operational systems. Therefore, until more data are available for hydrogen systems the startup cost is assumed to be negligible.

$$R_{Startup} = \sum_{t=1}^{n} P_{start,x} \cdot x_i^{start} + P_{start,y} \cdot y_i^{start} \quad \text{Eq. 6}$$

The last revenue stream is from the sale of hydrogen and is expressed as follows:

$$R_{H2} = \sum_{t=1}^{n} P_{H2} \cdot z_i^{H2\,sold} \quad \text{Eq. 7}$$

where P_{H2} is the price of hydrogen and $z^{H2\,sold}$ is the amount of hydrogen sold from storage. For this analysis a fixed hydrogen price, which does not change with time, is used.

The storage level is maintained using the following equation at every time step:

$$z_i^{store} = z_{i-1}^{store} - x_i^{pwr}/\eta_x + y_i^{pwr} \cdot \eta_y - z_i^{H2\,sold} \quad \text{Eq. 8}$$

where z^{store} is the storage level and η_x and η_y are the efficiency for the output and input devices, respectively.

Outputs from the model include, most notably, the time-resolved operating profiles for the output and input devices, storage level, and each revenue stream. The model is written in GAMS (Rosenthal 2014) and is based on the model described in Townsend (2013).

4.2 Cost Calculations

System cost comprises capital cost, fixed operation and maintenance (FOM) costs, and a cost multiplier for installation. The total system cost is annualized over the equipment lifetime with an assumed 7% interest rate as shown in Equation 9. For this analysis it is assumed that there is no initial equity investment and taxes are not included. This analysis does not require a specific chemistry for the stationary hydrogen fuel cell or electrolyzer to be selected; however, cost and performance values are most similar to proton exchange membrane systems.

$$Annual\ Payment = Net\ Present\ Costs \cdot \left(r + \frac{r}{(1+r)^n - 1}\right) \quad \text{Eq. 9}$$

Net Present Cost is the summation of all capital costs and FOM costs over the lifetime of the equipment, r is the interest rate, and n is the lifetime of the equipment.

Electricity markets and natural gas prices represent 2012 values for California. It is assumed that the price profiles are the same for each year for the lifetime of the equipment. The authors recognize that the prices will change from year to year. However, with additional renewables and changes to markets within California, it is unclear how the prices will be affected (Hummon et al. 2013; Weron 2014), so for this study price profiles are assumed to be the same from year to year.

The capital cost and FOM costs in the results represent a range from current costs to more optimistic future costs. Power rating for each technology is 1 MW and the steam methane reformer is sized to produce the same amount of hydrogen that is sold by the other systems (400 kg/day).[2] Default values for energy storage capacity are shown in Table 2; however, a sensitivity analysis is performed on the energy storage capacity to explore the value of additional storage for hydrogen systems. Additionally, the cost of hydrogen storage is only applied once for systems combining an electrolyzer and a fuel cell because they share the same storage system.

4.3 System Configurations

Twelve unique configurations are analyzed for cost competitiveness. A summary of the configurations is shown in Table 3. Multiple technologies, multiple operating strategies (i.e., energy markets only and providing both energy and ancillary services), and multiple uses (e.g., electricity markets and sale of hydrogen) are explored.

Table 3. List of System Configurations

Technologies		Short Name	Grid Services Provided	Hydrogen Sold
1	Pumped Hydro	HYPS Eonly	Energy markets only	No
2	Pumped Hydro	HYPS All	Energy and ancillary services	No
3	Lead Acid Battery	Batt Eonly	Energy markets only	No
4	Lead Acid Battery	Batt All	Energy and ancillary services	No
5	Fuel Cell and Electrolyzer	FC-EY Eonly	Energy markets only	No
6	Fuel Cell and Electrolyzer	FC-EY All	Energy and ancillary services	No
7	Fuel Cell and Electrolyzer	FC-EY Eonly	Energy markets only	Yes, 400 kg/day (80%)
8	Fuel Cell and Electrolyzer	FC-EY All	Energy and ancillary services	Yes, 400 kg/day (80%)
9	Steam Methane Reformer	SMR Baseload	No services (baseload operation)	Yes, 400 kg/day (100%)
10	Electrolyzer	EY Baseload	No services (baseload operation)	Yes, 400 kg/day (80%)
11	Electrolyzer	EY Eonly	Energy markets only	Yes, 400 kg/day (80%)
12	Electrolyzer	EY All	Energy and ancillary services	Yes, 400 kg/day (80%)

[2] The 1 MW electrolyzers can produce close to 500 kg/day and are operated with an 80% capacity factor for the year resulting in 400 kg/day actual output. The SMR system can produce 400 kg/day and operates with a 100% capacity factor.

Participation in only energy markets relies on price arbitrage to achieve value. Participating in both energy and ancillary service markets means that some energy is used for arbitrage—when the on-peak/off-peak price split is sufficiently high to provide more revenue than providing ancillary services—but the majority of the time, power is used for providing ancillary services. The optimization determines when the system should focus on participating in energy markets, providing ancillary services, or both.

Currently, most electrolyzer facilities do not offer flexible demand to the grid and operate with a relatively flat electrical consumption and hydrogen production profile; however, these systems can respond very rapidly and provide a variety of grid services, which are not presently utilized. For electrolyzers that provide demand response, participating in only energy markets essentially means purchasing electricity when it is the least expensive to lower the total feedstock cost. Participating in both energy and ancillary service markets involves modulating consumption to pursue low cost electricity and providing ancillary service support whenever possible.

It is assumed that for the scenarios that allow for the sale of hydrogen, a fixed amount must be produced (i.e., 400 kg/day) and the demand for hydrogen is constant. This creates a situation where the hydrogen storage tank provides a buffer between when the hydrogen is produced and when it is consumed. That allows the electrolyzer to change its electricity consumption profile to provide ancillary services while also meeting any contractual hydrogen production requirements. The authors have explored the impacts of variable hydrogen demand profiles based on fueling station data. Using the available data, the impacts on operational revenue were less than 1% compared to constant demand and, as a result, are not included below. Lastly, while steam methane reformers can ramp up and down to meet hydrogen demand, because the natural gas price is constant and their electricity consumption is two orders of magnitude lower than that of the electrolyzers, the reformers maintain a constant operating profile and do not modulate production.

5 Results

The operations optimization model was run using a variety of technologies and operating strategies as presented in Table 3. The cost for each case is compared to the maximum achievable revenue in Figure 3. The cost model was described in the previous section and the yearly revenue is calculated as the revenue from the provision of ancillary services and the sale of hydrogen, less the electricity or gas feedstock cost.

The figure is separated into two sections. The first six technologies from Table 3 do not include the sale of hydrogen and only take in electricity, store energy, and output it at a later time (i.e., electricity-in, electricity-out systems). Technologies 7 to 12 from Table 3 assume that 400 kg of hydrogen per day is sold, which amounts to 80% of the potential hydrogen production for electrolyzers and 100% of the hydrogen production for SMR systems. The hydrogen can be produced at any time and drawn from the storage tank when needed. This assumption ensures there is a steady supply of hydrogen for customers and capacity for systems to shift when hydrogen is produced and provide ancillary services. Technologies 7 and 8 can operate as storage systems while technologies 9 to 12 operate as demand response systems. Electrolyzers and SMR units can operate as demand response devices when a fuel cell or combustion device is not attached. They consume electricity or gas to produce and store hydrogen and provide demand-side flexibility, but they do not re-generate electricity.

The range of revenue for the configurations that sell hydrogen represents a range of potential sale prices for hydrogen from \$3/kg to \$10/kg. The future market value for hydrogen is likely dependent on which markets are targeted so a range is used, allowing the reader to see the impact on revenue from different hydrogen sale prices. Similarly, the high end of the system cost range represents a current case and the low end represents a more optimistic future case. See Table 2 for more details.

As shown in Figure 3, hydrogen systems that do not sell hydrogen have a lower revenue and higher cost than conventional storage technologies. This is due to a lower round trip efficiency and higher capital cost for the fuel cell. As a result, when providing strictly electrical energy storage, it is challenging for hydrogen technologies to compete against conventional technologies using the selected California electricity markets. Hydrogen produced by an electrolyzer or SMR and sold at \$3–\$10/kg as a fuel is more valuable than the electricity generated using a fuel cell. Consequently, systems that can sell hydrogen should sell as much as possible, while providing ancillary services and on occasion selling electricity if the price differential is sufficiently high. For hydrogen storage systems, a 1 MW fuel cell is assumed, which increases the cost while only operating a few hours each year during periods of high price differentials, and only marginally increasing the value. For this analysis the same capacity of fuel cell and electrolyzer are installed; however, there may be opportunities to reduce the cost while still providing the increased system flexibility that comes with adding a fuel cell by installing a smaller fuel cell.

In all cases, systems providing both energy and ancillary services (i.e., “All”) generate more revenue than systems only participating in energy markets (i.e., “Eonly”). This is because providing additional services creates additional revenue streams that were previously not accessible. The last four cases are particularly promising for hydrogen technologies. These cases sell all of the hydrogen and do not re-generate any electricity. SMR is currently the most widely used technology for hydrogen production and, as expected, shows the greatest revenue margin. Electrolyzers are currently operated most often in baseload mode; however, there is significant value to capture from participating in electricity markets. By participating in energy markets and modulating operating load to minimize its electricity cost, the electrolyzer can increase revenues by $23/kW-yr; providing both energy and ancillary services increases that value to $57/kW-yr and, if the system is eligible, a capacity payment can provide additional revenue (i.e., $150/kW-yr for this analysis).

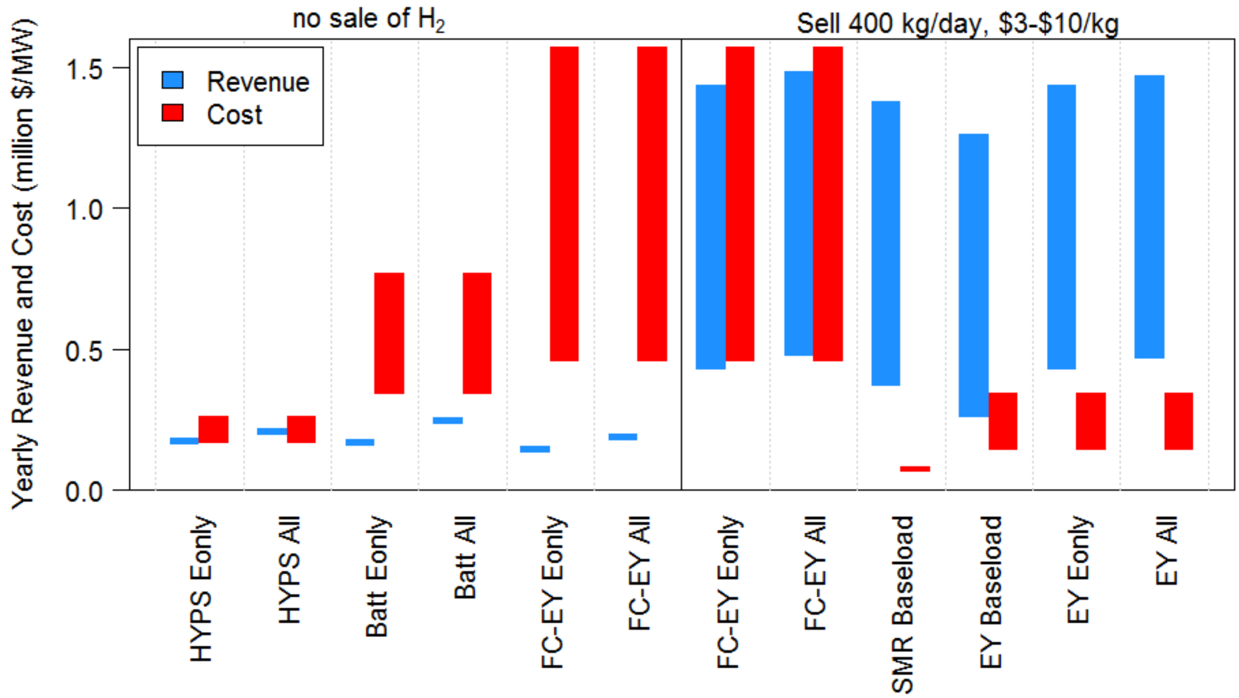

Figure 3. Comparison of cost versus electricity market revenue for conventional and hydrogen technologies ($3–$10/kg represents a range of potential sale prices for hydrogen)

In addition to looking at systems that produce 80% of the potential hydrogen (400 kg/day), an analysis was performed that looked at producing only 20% or 100 kg/day to understand the potential for oversizing equipment to focus on revenues from provision of grid services. The results show similar behavior as the 400 kg/day cases, except for two things:

1. The revenues are significantly lower because less hydrogen is sold. The value for hydrogen is greater than electricity even at $3/kg, resulting in much less revenue than for the 400 kg/day scenarios.
2. The 100 kg/day systems focused more on regulation down (a lower value product) than on regulation up. This is because electrolyzers are only able to provide regulation up when they are producing hydrogen, which for 100 kg/day represents only 20% of the time, which will be much less than 80% for the 400 kg/day scenarios.

A breakdown of revenue streams is shown in Figure 4. The capacity payment value is $150/kW-yr. All technologies except the "SMR baseload" and "EY baseload" receive this payment. These do not receive a payment because they are not modulated to respond to grid needs.

For the technologies that do not sell hydrogen (i.e., first six), the resulting revenue received from energy and/or ancillary services (not including capacity payment) ranges from \$0/kW-yr to \$107/kW-yr. For the technologies that sell hydrogen (i.e., last six), the resulting revenue from hydrogen and energy and/or ancillary services ranges from \$255/kW-yr to \$368/kW-yr, mainly from the sale of hydrogen. Energy market revenues include both the purchase and sale of electricity so the value can be negative, particularly for technologies that sell hydrogen. When considering the selected California wholesale electricity markets, the main business for hydrogen equipment should be producing and selling hydrogen. Providing services to the grid can supplement that revenue.

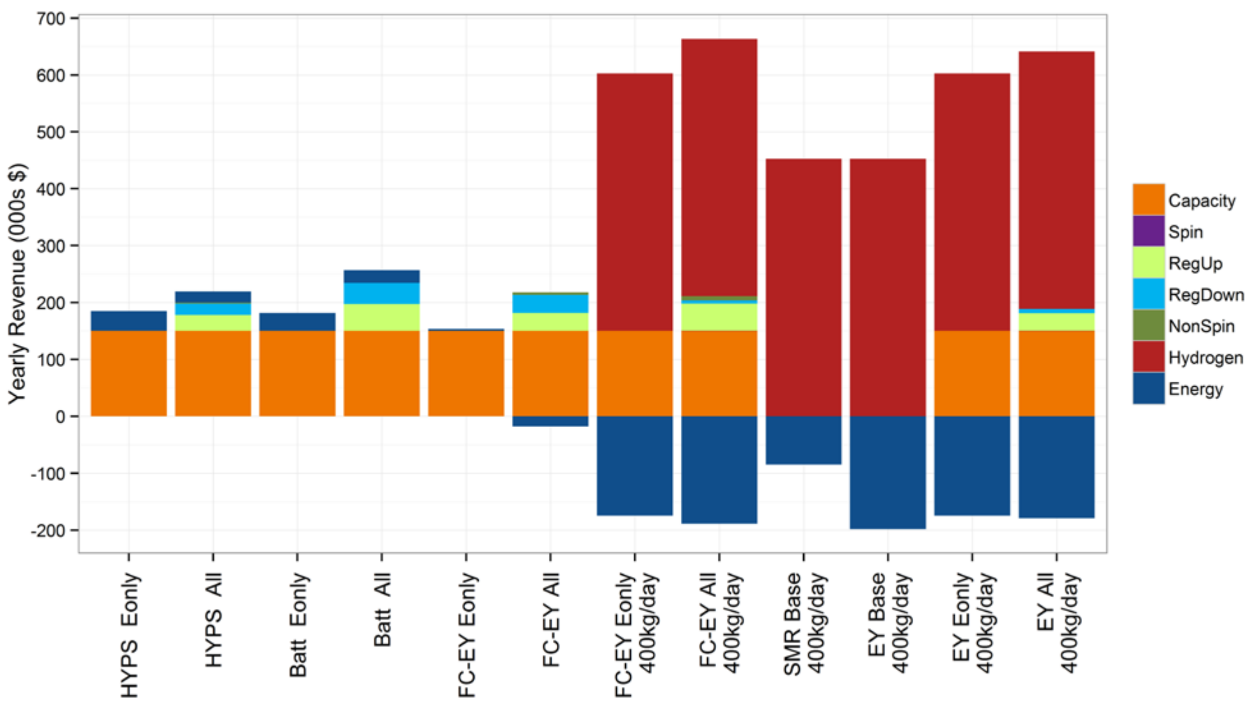

Figure 4. Breakdown of electricity market revenues with a hydrogen sale price of \$3/kg

Hydrogen systems are able to scale the energy storage capacity independently of the power capacity. This allows for systems with very high energy-to-power ratios (i.e., long duration storage). A sensitivity analysis was performed on the additional value for increasing the energy storage capacity at rated power from 3 hours to 168 hours (1 week) to determine the current market value for long term storage within California. This case is interesting because variable renewable generation may experience extended periods of low or no generation during events where the sky is cloudy or when there is insufficient wind for several days at a time. There are several options to mitigate this challenge including maintaining sufficient backup fossil generation, greatly increased demand-side management, and long duration storage. Long duration storage offers the opportunity to mitigate extended periods of limited renewable generation while not using fossil fuels and without the potential to impact customer usage and behavior.

Two cases were explored: (1) a fuel cell and electrolyzer storage system capable of providing energy and ancillary services that sells 400 kg/day of hydrogen and (2) the same system that cannot sell hydrogen. Figure 5 presents results for the system that can sell hydrogen. The horizontal dotted line is positioned at the maximum revenue value for the 3 hour storage device and provides a reference for all of the subsequent items. Above-ground tanks are used for storage so the cost increases linearly as the required storage capacity increases. The use of underground hydrogen storage has been shown to dramatically reduce the cost for high volume storage (Steward et al. 2009). That would reduce the increase in cost for the system; however, the expected revenue values are independent of the type of storage technology used.

The revenue slightly increases with additional capacity (i.e., $17,500/year when increasing from 3 hours to 168 hours of storage). The horizontal dotted line in Figure 5 is used for reference to see the relative difference in yearly revenue. The maximum revenue-to-cost ratio occurs for 4 hours of storage and is very similar for storage durations between 3 and 8 hours. However, for durations greater than 16 hours of storage, using above ground storage tanks, the revenue-to-cost ratio falls below 1 and continues to fall for all higher durations of storage. While the exact optimal value for storage operation is specific to the assumptions in this study, this result reflects the importance of targeting diurnal price differences in current markets. This exercise was repeated with a fuel cell and electrolyzer system that cannot sell hydrogen and even less of a revenue increase was seen (i.e., $2,700/year increase in revenue for a 56 times increase in storage capacity). This shows that more storage capacity is not necessarily more valuable in California's current energy and ancillary service markets.

Based on select markets in California, the only mechanism to compensate users for long-term storage is the energy price differential from arbitrage and, potentially, capacity payments. However, the price differential and demand follow a diurnal pattern, which means that the majority of value is achievable with less than one day of storage. High penetration of renewables is causing concern with system flexibility and overgeneration. These challenges reinforce the importance of diurnal storage but also should encourage mechanisms to value longer-duration storage in the future.

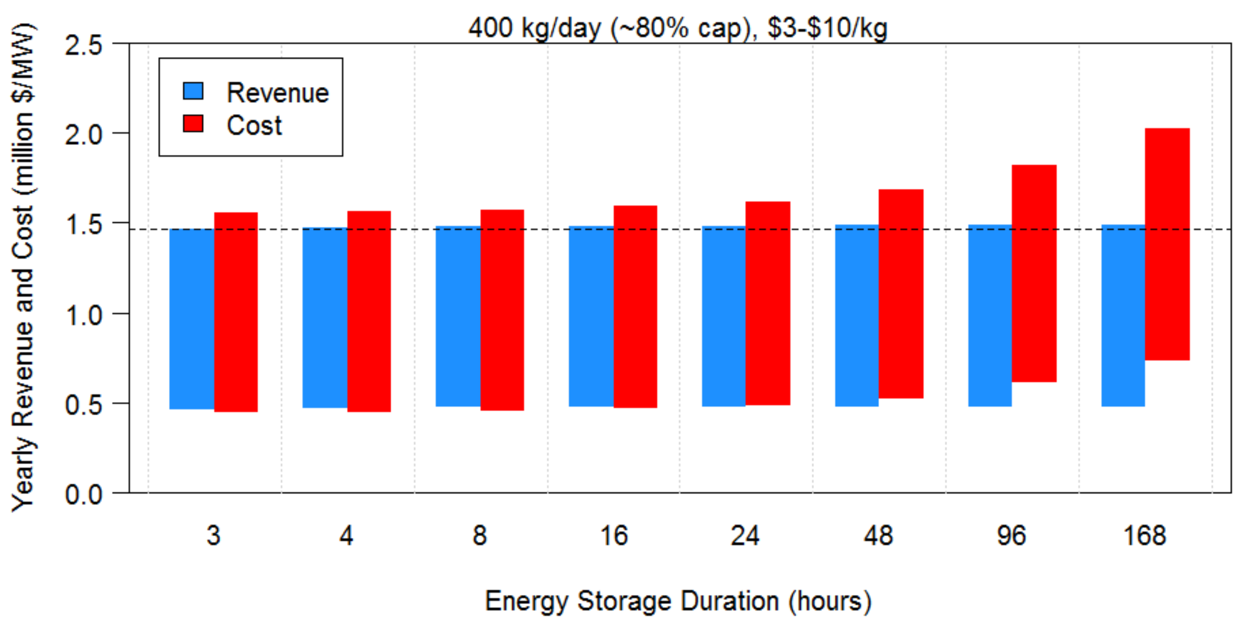

Figure 5. Storage capacity sensitivity analysis for "FC-EY All" from 3 to 168 hours of storage

6 Conclusions

Hydrogen technologies offer unique system flexibility that can enable interactions between multiple energy applications including electricity, transportation, heating fuel, and industrial processes. Previous research established that hydrogen technologies, and in particular electrolyzers, can respond fast enough and for sufficient duration to participate in electricity markets. To date, there has been little work done to assess the potential economic value of electricity market participation for hydrogen systems. The present work explores the value from a subset of California electricity markets including energy, regulation, spinning reserve, and non-spinning reserve. This work recognizes that participation in electricity markets can enhance the revenue streams available for hydrogen storage systems and quantifies the economic competitiveness of these systems compared to conventional energy storage technologies.

The value of participation in energy, ancillary service, and capacity markets is explored and the key results are as follows.

- **Hydrogen systems should focus on selling hydrogen.** Using historical wholesale electricity prices in California, a system that can produce hydrogen is more competitive if it sells its hydrogen than if it is used to generate electricity. This is largely due to a low round-trip efficiency for “electricity-in, electricity-out” hydrogen storage systems and the increase in system cost from the addition of a fuel cell.
- **Participation in energy, ancillary service, and capacity markets yields the greatest revenue.** Hydrogen systems capable of providing ancillary services achieve higher revenues than systems engaging in only energy markets, which in turn can receive greater revenue than systems operating with typical baseload or constant output profiles.
- **More storage capacity is not necessarily more competitive in current energy and ancillary service markets.** Current electricity markets in California do not have a specific mechanism for valuing long-term storage and rely on the energy price differential. Consequently, revenues only slightly increase for systems with a day or even a week of storage—not enough to overcome the costs of adding additional storage capacity beyond that required to manage diurnal variations.

7 Future Work

The current study used CAISO 2012 historical data, but there are differences in the markets available and prices for each region and from year to year. Future work will focus on expanding the list of markets explored to include flexible ramping and other new services as they develop, updating the analysis to current-year values, and expanding the regions considered beyond California.

As mentioned in the approach, the operations optimization model assumes that systems are not large enough to impact market prices. However, with widespread roll-out of hydrogen technologies and especially electrolyzers to support renewable integration and provide transportation fuel, there are concerns about impacts on electricity markets of introducing such a large flexible load on the system. Those impacts are not captured in this effort. It is difficult to predict how market prices will be affected by changes to the system (Hummon et al. 2013; Weron 2014) or whether the ancillary service markets are deep enough to support significant increases in energy storage and dispatchable demand-side resources (Denholm et al. 2015). Integrating hydrogen technologies into production cost models would allow for the system impacts of energy storage and large dispatchable loads to be assessed. This work could quantify the difference in value for the price-taker methodology, presented here, and full system production runs where market prices can be impacted.

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